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INTERNATIONAL CENTER
ON SMALL HYDROPOWER

World Small Hydropower Development Report 2022

Consolidated Version

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Foreword

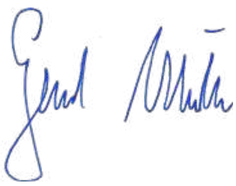
by **Gerd Müller, UNIDO Director General** for World Small Hydropower Development Report 2022 Executive Summary

The COVID-19 pandemic caught the world unprepared for a complex, systemic challenge of such a scale. Livelihoods, economic progress, and social stability have been severely impacted worldwide. The COVID-19 pandemic has also slowed progress towards sustainable energy goals. In such a critical moment when multiple crises are coming together, we need a decisive collective effort to follow through on the goals the world community agreed on to build sustainable energy systems. We must make sure that renewable energy development is a top priority at all levels of decision-making.

In the face of this challenge, it is especially critical to continue to collect and share knowledge about the various renewable energy technologies. Small hydropower is one of such solutions. It has long played a key part in providing access to sustainable and reliable electricity around the world. Small hydropower is a simple, adaptable and low-cost technology, which makes it particularly suitable for remote and marginalized communities. When planned with environmental and socio-economic aspects in mind, it provides access to sustainable renewable energy, the basis for any development which also empowers communities, improves livelihoods and is the basis for more development opportunities. Small hydropower offers one answer to many questions posed by the pandemic, climate crisis and energy transition for achieving the commitments under the Paris Agreement.

Over 60 per cent of global small hydropower potential remains untapped. There are still vast opportunities across the globe to use it for the benefit of local communities and the planet. In order to support policy-makers, communities, potential developers and other stakeholders interested in developing small hydropower projects, the United Nations Industrial Development Organization (UNIDO) partnered with the International Center on Small Hydro Power (ICSHP) to launch the fourth edition of the World Small Hydropower Development Report. The first three editions have shown that the report is a much-needed global knowledge product on small hydropower. I am proud that that this is already the fourth edition of the report and that UNIDO and ICSHP are continuing this important work of knowledge gathering and distribution. The valuable content of the current edition is an outcome of a collective effort of more than 200 experts and contributing organizations from all over the world. The production of this comprehensive report would not have been possible without generous support and intellectual leadership from the Ministry of Water Resources of the People's Republic of China and ICSHP.

I am confident that this report will contribute to the global effort to build sustainable energy systems that will help mitigate the climate crisis and empower communities.



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The preparation of this thematic publication was headed by LIU Heng, Senior Technical Advisor at UNIDO and consulted by HU Xiaobo, Chief of the Division of the Multilateral Development at ICSHP. The work was coordinated by Oxana Lopatina at ICSHP and Eva Krēmere at UNIDO. The publication is the result of three years of intense research work and was backed by a talented and indispensable team of researchers at ICSHP and a vast number of experts in the field of small hydropower

WSHPDR2022 team

Head	LIU Heng — Senior Technical Advisor, United Nations Industrial Development Organization (UNIDO)
Coordinators	Oxana Lopatina — International Center on Small Hydro Power (ICSHP)
	Eva Krēmere — United Nations Industrial Development Organization (UNIDO)
Team	UNIDO: Eva Krēmere, Sanja Komadina. Interns: LIU Fangjie, REN Wenxuan
	ICSHP: HU Xiaobo, Oxana Lopatina, Danila Podobed, Alicia Chen Luo, Veronika Spurna, Tamsyn Lonsdale-Smith, Bilal Amjad, Oluwatimilehin Paul Olawale-Johnson, Davy Rutajoga, Laura Stamm, Ruize Yuan, BAO Lina, ZHANG Yingnan, Yan Ding

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Contributing Experts

Arturo Alarcon, Sameer Algburi, Alsamaoal Almoustafa, Gabrial Anandarajah, Vicky Ariyanti, Fredrick Arnesen, Engku Ahmad Azrulhisham, Ayurzana Badarch, BAO Lina, Mathieu Barnoud, Alexis Baúles, Sow Aissatou Billy, Alaeddin Bobat, Frank Charles Ramírez Bogovich, Ejaz Hussain Butt, Abou Kawass Camara, Jose Campos, Joan Cecilia C. Casila, Piseth Chea, Julian Chin, Salim Chitou, Gift Chiwayula, Brenda Musonda Chizinga, Nouri Chtourou, Romao Grisi Cleber, Ryan Cobb, Poullette Faraon Chaul Corona, John Cotton, Slobodan Cvetkovic, Manana Dadiani, Asger Dall, Bassam Al Darwich, Denise Delvalle, Tobias Dertmann, Gabriel Chol Dhieu, Jonas Dobias, Aurélie Dousset, Choten Duba, José Rogelio Fábrega Duque, Nadia Eshra, Cayetano Espejo Marín, Paola Estenssoro, Soukaina Fersi, Geraldo Lúcio Tiago Filho, Danilo Fras, Fujimoto Tokihiko, Patrick Furrer, Camila Galhardo, Ramón García Marín, Adnan Ghafoor, Gaëlle Gilboire, Zelalem Girma, Mohammad Hajilari, Geon Hanson, Richard Hendriks, Mabikana Voula Boniface Hervé, Yan Huang, Chinedum Ibegbulam, Michela Izzo, Jamal Jaber, Gordana Janevska, Sergio Armando Trelles Jasso, Rim Jemli, Marco Antonio Jimenez, Annabel Johnstone, Julien Jomaux, Wim Jonker Klunne, Abdoul Karim Kagone, John K. Kaldellis, Bryan Karney, Raul Pablo Karpowicz, Egidijus Kasiulis, Shorai Kavu, Eleonora Kazakova, Joseph Kenfack, Dong Hyun Kim, George Kimbowa, Dimitar Kisliakov, Maris Klavins, Ioannis Kougias, Rastislav Kragic, Arun Kumar, Sarah Kwach, Kristian Dahl Larsen, Seung Oh Lee, Jean-Marc Levy, Bryan Leyland, Laura Lizano, Galina Livingstone, Kimberly Lyon, Sarmad Nozad Mahmood, Ewa Malicka, Pedro Manso, Andrés Teodoro Wehrle Martínez, Anik Masfiqur, Mareledi Gina Maswabi, Hamid Mehinovic, Juan José García Méndez, Luiza Fortes Miranda, Guram Mirinashvili, Julio Montenegro, Bastian Morvan, Reynolds Mukuka, Béla Munkácsy, Patricio Muñoz, Wakati Ramadhani Mwaruka, Thet Myo, N'guessan Pacôme N'Cho, Sea Naichy, Niels Nielsen, Gilbert Nzobadila, Emna Omri, Karim Osseiran, Sok Oudam, Victor Odundo Owuor, Grant Pace, Aung Thet Paing, Hok Panha, Sotir Panovski, Ahmet Penjiev, Georgy Petrov, Alexandra Planas, Bogdan Popa, Cecilia Correa Poseiro, Sunil Poudel, Ravita D. Prasad, Kenneth Bengtson Tellesen Primdal, Leonardo Peña Pupo, Thoeung Puthearum, Emanuele Quaranta, Samira Rasolkhani, Atul Raturi, Thomas Buchsbaum Regner, António Carmona Rodrigues, Jorge Saavedra, Najib Rahman Sabory, Victor Sagastume, Esmina Sahic, Alberto Sanchez, Karine Sargsyan, Vahan Sargsyan, Goran Sekulić, Ozturk Selvitop, Shamsuddin Shahid, Stafford W. Sheehan, Manish Shrestha, Sangam Shrestha, Mundia Simainga, Gjergji Simaku, Martin Sinjala, Seming Skau, Nicolae Soloviov, Amine Boudghene Stambouli, Dmytro Stefanyshyn, Pavel Štípský, Jean Sumaili, Dinesh Surroop, Areli Sutherland, Alberto Tena, Pierre Kenol Thys, Anastasiya Timashenok, Panagiotis Triantafyllou, Alexander Urbanovich, Joelinet Vanomaro, Goran Vasilic, Ciza Willy, Ernesto Yoel Fariñas Wong, Gendensuren Yondongombo, Saida Yusupova

Executive Summary

Preface

Providing universal access to energy remains one of the most critical economic, environmental and development challenges facing the world today with over 700 million people, or 9.5 per cent of the global population, predominantly in rural areas, still lacking access to electricity in 2020.1 Access to reliable and affordable electricity has an immediate and transformative impact on the quality of life and is crucial to ensuring access to such basic services as healthcare and education. At the same time, in both developing and developed countries, the need for clean and sustainable sources of energy is growing more acute in the face of the climate crisis and environmental degradation. Sustainable renewable energy is, thus, a key building block towards both the broader development goals, including poverty eradication and public services provision, and climate crisis mitigation and prevention of environmental degradation.

As the lowest-cost renewable energy technology, hydropower remains integral to international efforts to fight the climate crisis and ensure a clean energy future. Small hydropower (SHP), due to its adaptability to the local needs and conditions and suitability for remote rural areas with low-density energy demand, has been at the centre of development strategies worldwide, whilst helping reduce greenhouse gas emissions and promoting greater energy independence. If effectively and sensitively planned, SHP projects can also offer opportunities for the empowerment of local communities, including the usually disadvantaged groups, such as women and youth, empowering them economically and contributing to progress towards greater equality.

In order to more effectively promote SHP as a renewable and rural energy solution and overcome existing barriers, it is essential to identify the development status of the technology across regions and engage stakeholders to share existing knowledge and experience. Prior to the first edition of the World Small Hydropower Development Report (WSHPDR) published in 2013, it was clear that a comprehensive reference publication for decision-makers, stakeholders and potential investors was needed. Today, the WSHPDR is the only global publication dedicated to the dissemination of in-depth information on SHP development.

For the fourth time, the United Nations Industrial Development Organization (UNIDO) and the International Center on Small Hydro Power (ICSHP), as the global knowledge leaders in the SHP sector, are continuing their partnership for the new edition of the report, the WSHPDR 2022. The new edition contains 20 regional chapters, 166 country chapters, 12 case studies, 3 thematic publications as well as a global database of existing and planned SHP plants. The WSHPDR 2022 is the result of an enormous collaborative effort between UNIDO, ICSHP and over 200 local and regional SHP experts from across the globe, including engineers, academics and government officials. The current edition of the Report aims not only to provide an update on the SHP status by country but also to expand on the first three editions by providing improvements in data accuracy with enhanced analysis and a more comprehensive overview of the sector by country.

What is new?

Compared to the previous editions, the *WSHPDR 2022* offers a more detailed analysis of the SHP status by country, covering such aspects as operational, planned and potential SHP projects, cost of SHP development, financial mechanisms available for SHP projects, effects of the climate crisis on SHP as well as factors favouring further SHP development. Furthermore, the new edition includes three thematic publications addressing the topics of gender equality, youth involvement and climate change from the perspective of SHP as well as the first global database of developed and planned SHP projects by country. Finally, the current edition includes a collection of new case studies illustrating successful examples of SHP implementation, focusing on the social benefits of SHP projects, as well as new technological solutions available.

Global overview

According to the *WSHPDR 2022*, the global installed SHP capacity for plants of ≤10 MW is estimated at approximately 79.0 GW and the total known potential for SHP ≤10 MW (including developed capacities) is estimated at 221.7 GW. Thus, despite the appeal and benefits of SHP solutions, much of the world's SHP potential remains untapped (64 per cent). It should be noted that for a number of countries, including those with very developed SHP sectors (for example, India), data on SHP of ≤10 MW are not available due to the use of different local definitions. Therefore, the global installed and potential capacity can be assumed to be somewhat higher than the reported totals.

Compared to the *WSHPDR 2019*, SHP installed capacity (≤10 MW) increased by 1 per cent (Figure 1). At the same time, the estimated SHP potential decreased by 3 per cent (Figure 2) based on more accurate data obtained for a number of countries, including Norway, Turkey and the Philippines, as well as due to the lack of data on SHP of ≤10 MW for some other countries.

Figure 1.
Global Installed Capacity of Small Hydropower of ≤10 MW in the WSHPDR 2013/2016/2019/2022 (GW)

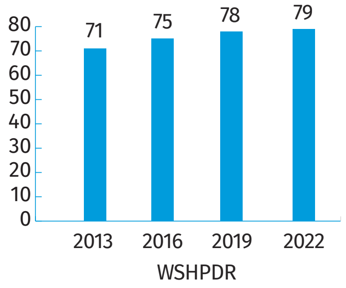
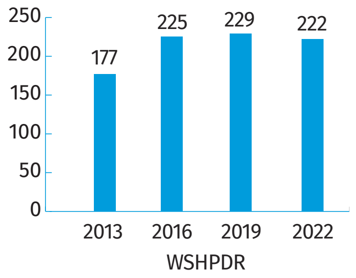
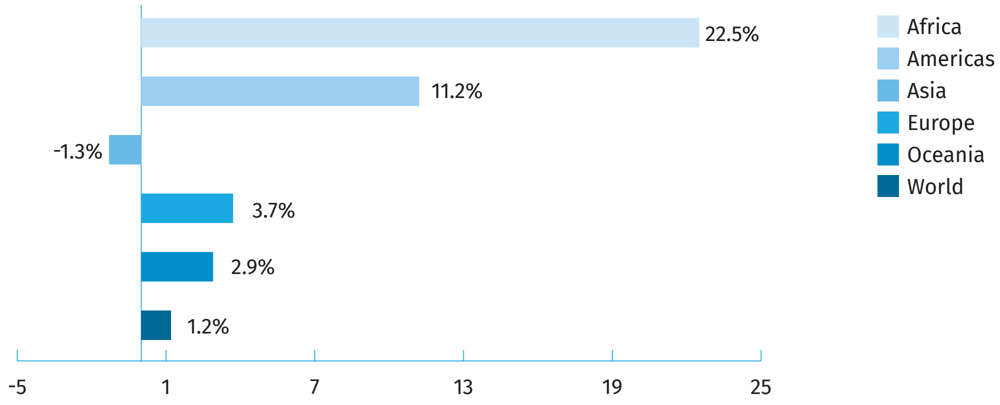


Figure 2.
Global Potential Capacity of Small Hydropower of ≤10 MW in the WSHPDR 2013/2016/2019/2022 (GW)



The greatest relative increase in installed SHP capacity compared to the *WSHPDR 2019* is reported for Africa with an increase of almost 23 per cent (Figure 3). The Americas, Europe and Oceania have also seen an increase in installed SHP capacity of approximately 11 per cent, 4 per cent and 3 per cent, respectively, compared to the previous edition of the Report. In absolute terms, the largest increase in installed capacity is reported for Europe at 734 MW, followed by the Americas with 698 MW and Africa with 134 MW of new capacity. Conversely, the reported SHP installed capacity of Asia decreased by approximately 1 per cent, as a result of an updated estimation for Turkey as well as a lack of data for the 10 MW definition for some countries.

Figure 3.
Change in Installed Small Hydropower Capacity between the WSHPDR 2019 and the WSHPDR 2022 by Continent (%)



SHP (of ≤10 MW) represents approximately 1 per cent of the total electricity installed capacity of the countries included in this Report and 6 per cent of their total installed hydropower capacity. Asia continues to have the largest installed capacity and potential for SHP of ≤10 MW, accounting 64 per cent and 63 per cent of the global total, respectively (Figures 4 and 5). Europe has the highest percentage of SHP development (52 per cent for SHP ≤10 MW), with Western Europe having 83 per cent of its known potential already developed. The largest known undeveloped SHP potentials are concentrated in Central Asia, Eastern Asia and South-Eastern Asia (Figure 6).

Figure 4.
Share of Global Installed Small Hydropower Capacity of ≤ 10 MW by Continent (%)

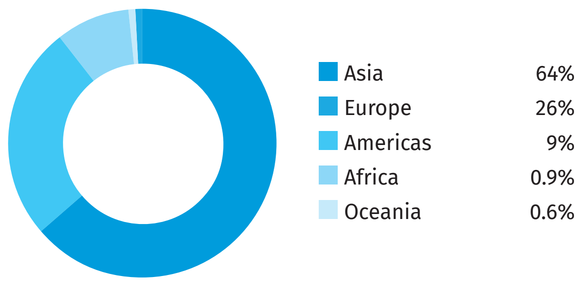


Figure 5
Share of Global Small Hydropower Potential of ≤ 10 MW by Continent (%)

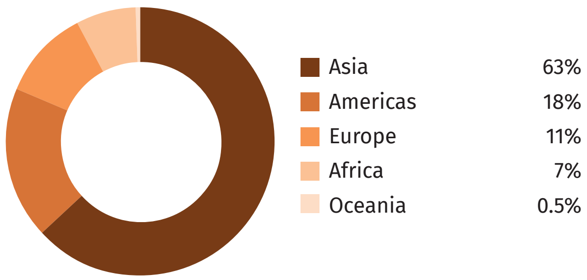
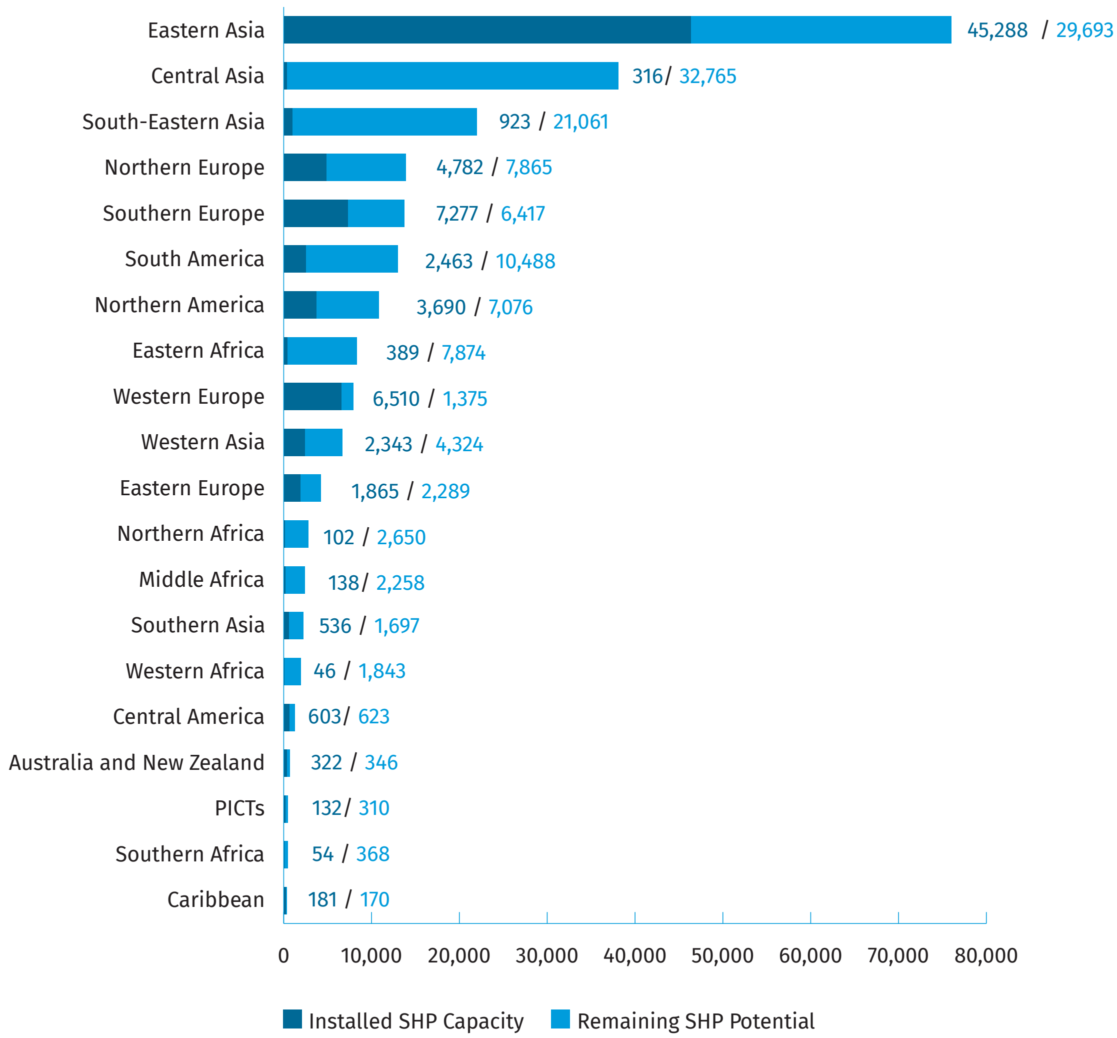
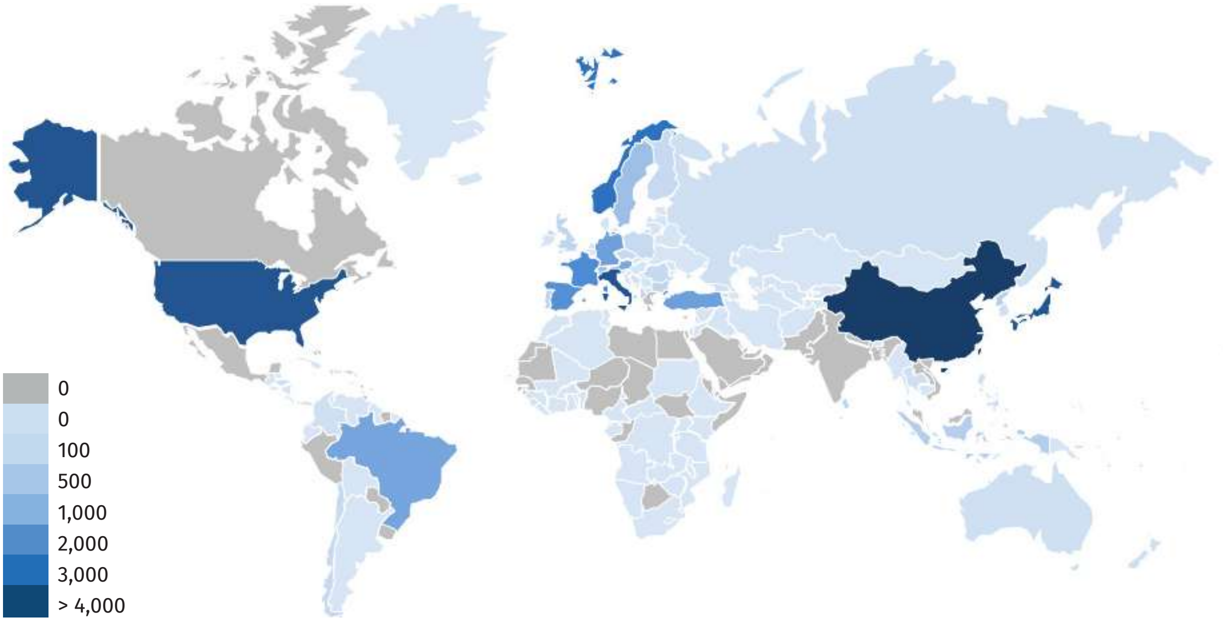


Figure 6.
Developed and Remaining Small Hydropower Potential of ≤10 MW by Region (MW)



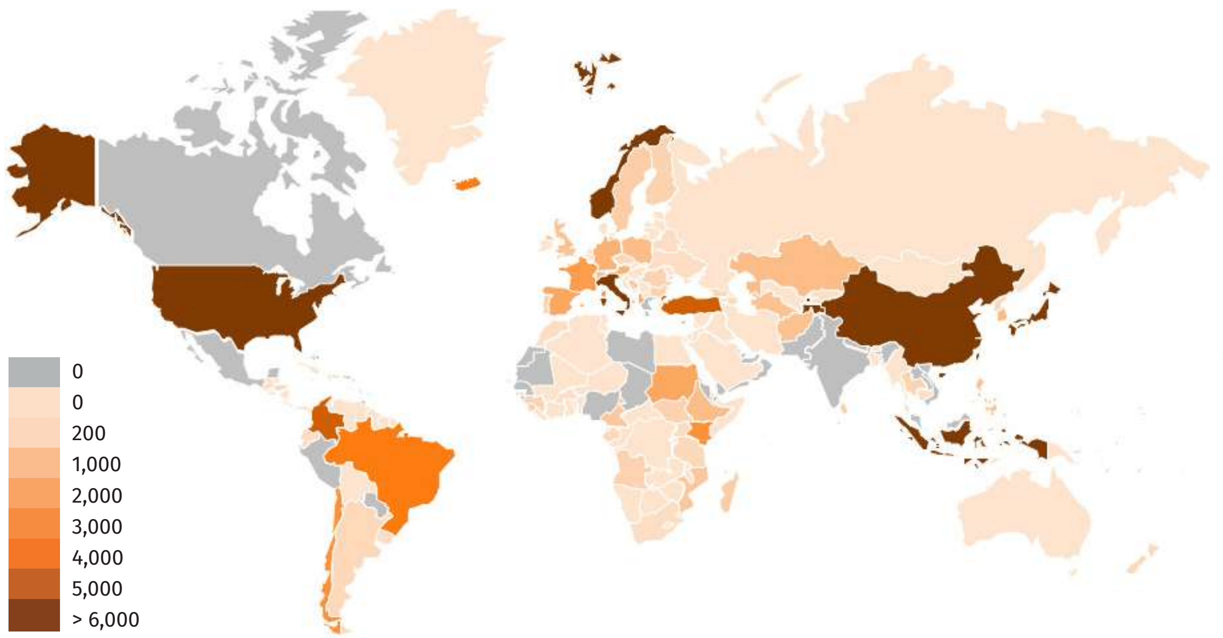
China continues to dominate the global SHP landscape, with 53 per cent of the world's total SHP installed capacity (definition of ≤10 MW) and approximately 29 per cent of the world's total known SHP potential. In terms of installed capacity, China is followed by the United States of America (USA), Italy, Japan and Norway. Together, these five countries account for almost 71 per cent of the world's total installed capacity of SHP ≤10 MW.

Figure 7.
Small Hydropower Installed Capacity of ≤10 MW by Country (MW)



Note: Highlighted in grey are countries without data on SHP of ≤10 MW or no SHP plants installed.

Figure 8.
Small Hydropower Potential Capacity of ≤10 MW by Country (MW)



Note: Highlighted in grey are countries without data on SHP of ≤10 MW.

Africa

SHP in Africa can be characterized as having a relatively low level of installed capacity but with considerable potential for development. Climatic and topographic characteristics vary tremendously across the continent, resulting in a large variance in SHP potential in the north and south as compared to the east and west. The total installed capacity of SHP ≤10 MW in Africa is 729 MW and the total estimated potential is 15,714 MW. This indicates that less than 5 per cent of the known SHP potential of ≤10 MW has been developed so far.

Eastern Africa has the highest installed capacity of SHP of ≤10 MW on the continent (53 per cent of the continental total), followed by the Middle and Northern Africa regions. The highest known SHP potential is also found in Eastern Africa (also 53 per cent of the continental total), while the lowest potential is found in Southern Africa. Of all the countries in Africa, Uganda has the highest installed capacity of SHP of ≤10 MW (108 MW), whereas Kenya has the highest estimated potential for SHP of ≤10 MW (3,000 MW).

Americas

Northern America and South America dominate the SHP landscape in all of the Americas, with Brazil and the USA being leaders in terms of installed capacity and the USA also dominating in terms of known SHP potential. Countries in the Caribbean region have significantly smaller estimated potential. However, further studies could reveal a greater potential in the region as well as in other countries in the continent.

The total SHP capacity in the Americas is 6,937 MW, while the total potential is estimated at 25,294 MW for SHP of ≤10 MW. Some countries with enormous expected SHP potential have not performed feasibility studies to determine their exact potential capacity. Mexico, for example, is a country that is suspected to have significant SHP potential but no studies have been conducted yet. At the same time, in the current edition, the continent's reported potential significantly decreased compared to the previous edition, which is primarily due to the re-estimation of the potential of Colombia. According to the available data, approximately 27 per cent of the known SHP potential capacity in the Americas has been developed.

Asia

Asia has vast SHP resources, which are, however, unevenly distributed across the continent. The total installed SHP capacity of Asia is 50,406 MW and the total estimated potential is 139,946 MW (for SHP of ≤10 MW). This indicates that approximately 36 per cent has so far been developed. The decrease in reported SHP installed capacity in comparison with the *WSHPDR 2019* is primarily due to the re-estimation of the installed capacity data for Turkey.

China dominates not only the SHP landscape in Asia but also globally, accounting for over 83 per cent of the continent's installed capacity and 45 per cent of the known potential for SHP of ≤10 MW. SHP development is one of the major priorities for countries in Asia. The key motives for SHP development on the continent are to decrease dependence on energy imports and fossil fuels and to improve access to electricity, especially in rural areas.

Europe

Europe has a long history of SHP development, which has enabled it to reach a high level of installed capacity and potential development. The overall installed capacity of SHP of ≤10 MW in the region is 20,434 MW, while the potential capacity is estimated at 39,607 MW, indicating that 52 per cent of known potential has been developed. The increase in SHP installed capacity in comparison to the *WSHPDR 2019* is mainly due to the new capacities added in Norway, Italy and Albania.

With a wide variety of climates and landscapes in the continent, SHP potential varies across the regions. The greatest remaining potential is concentrated in Northern Europe, primarily in Norway. Italy is the leader in the continent in terms of installed capacity of SHP of ≤10 MW, followed by Norway and France.

Oceania

Oceania is the smallest region in terms of the number of countries included in this Report as well as in terms of installed and potential SHP capacity. The total installed capacity of SHP of ≤10 MW amounts to 454 MW, indicating an increase of 3 per cent in comparison to the *WSHPDR 2019*. The total estimated potential is 1,106 MW, thus, approximately 36 per cent has so far been developed.

The Oceania region is very diverse in terms of SHP potential. While all the countries receive enough rainfall to merit constant SHP production, only a few of the islands have mountainous terrain, which is usually a key factor for SHP potential. The Australia and New Zealand region is the richest area regarding SHP potential in Oceania, however, further SHP development is not foreseen in the region. On the other hand, the Pacific Island Countries and Territories (PICTs) are mostly flat islands and have little or no SHP potential, thus, making topography the key barrier.

Thematic publications

Compared to the previous editions, the *WSHPDR 2022* has been expanded with three thematic publications exploring three important aspects of SHP development: gender empowerment, youth involvement and climate change. The social and environmental aspects of SHP development often do not receive the needed attention and the particularities of the SHP technology can be lost in more general analyses devoted to renewable energy technologies or hydropower. These three publications aim to address this gap in the understanding of the SHP sector by exploring the specificity of the SHP technology in terms of how it both impacts and is impacted by gender dynamics, youth representation and climate change. The information gathered in these publications is based on literature reviews and expert and stakeholder interviews and is intended to highlight key themes within each topic as well as outline some of the most important directions for further research and analysis.

"How SHP empowers women and closes gender gaps and can do more"

Empowering women and girls and closing gender gaps are critical to realizing sustainable development goals (SDG) and ensuring a good quality of life for all. The energy sector, and in particular, decentralized systems such as SHP can facilitate the achievement of these targets. SHP can provide not only sustainable energy but also a steady baseload, which can facilitate positive changes to women's lives in the communities in which SHP plants are constructed and also beyond these communities.

In countries with low levels of access to electricity, benefits of access to electricity from SHP plants for women can include reduced time poverty and drudgery due to the use of electric appliances for household chores and economic activities. This immediately improves women's welfare but can also have knock-on benefits when such time is invested in studying, income generation and other life-enhancing activities. SHP development can also create direct and indirect jobs, provide power for productive uses and income generation and improve the delivery of critical social services including education and health services. Making the gender approach part of project design and implementation is critical to ensuring that SHP projects help empower women and girls across the globe, and close gender gaps. This publication discusses some of the ways in which SHP development is empowering women and girls and closing gender gaps between women and men. Further, it discusses the barriers to women's participation in the SHP sector and makes some key recommendations for addressing these barriers.

"Prospects for youth in the small hydropower sector"

Young people around the world can play a key role in creating the change required for the transformation of the global energy system, thus, contributing to regional and international development aims, while at the same time finding and creating opportunities for their own professional and personal development. While much of the world's SHP potential remains untapped, the SHP sector offers great opportunities for young professionals and entrepreneurs to get involved in providing clean energy to communities across the world. The active participation of youth in SHP can play a vital role in achieving a sustainable energy system because young people can bring the creative and forward-oriented thinking that is needed for a rapid energy transition. At the same time, young people continue to face multiple barriers in accessing the required skills to get involved in the sector as well often do not receive the needed policy, institutional and financial support.

This publication explores different opportunities that exist for youth in the SHP sector, with examples from around the world. It also analyzes the main barriers that young professionals considering joining or transitioning to the sector face as well as existing challenges faced by young energy professionals, including young women, already involved in the SHP sector. The report also provides a list of recommendations on how to overcome the existing barriers.

"Small hydropower and climate change"

Hydropower has a dual relationship with the climate crisis — it helps mitigate the impacts of changing climate but is also subject to vulnerability because of its dependence on the hydrological regime, which is affected by climatic conditions. Hydropower projects help displace fossil fuel energy sources (particularly, oil, coal and biomass in the case of SHP) and limit global warming. At the same time, changes in runoff due to climate change can have an effect in the short term (days, months) and the long run with significant implications for the productive uses of SHP plants. Climate change also induces effects in other sectors that can cascade to SHP plant operations, with competing water uses and different requirements from the grid also affecting the operations of SHP plants. However, climate change will impact hydropower generation in different ways depending on the region. Moreover, size influences the project's role in mitigation and adaptation to climate change. Due to limited capacity to store water and control floods, run-of-river SHP plants are particularly vulnerable to changing hydrological patterns.

The current publication offers a synopsis of projected climate change impacts on SHP by region as well as makes recommendations on climate change adaptation measures to be considered for climate change-resilient SHP and indicates the key directions for further research on the topic.

Global SHP Database

As part of the new edition of the *WSHPDR* and in collaboration with local experts, UNIDO and ICSHP have created the first Global SHP Database, which aims to gather in one place and make easily accessible detailed information on SHP projects worldwide. The database consists of two sections: (a) existing SHP plants and (b) planned and potential SHP projects. Currently, it includes data from 129 countries and territories across five continents, listing 6,249 existing SHP plants and 8,860 potential and planned plants. The database is intended to serve as a source of information on the current status of SHP development by country as well as on projects that are under development or are available for investment.

The database is based on the most accurate data available, however, the completeness of data varies from country to country. Moreover, some countries have legal restrictions on sharing data on power plants publicly and, hence, these countries were not included in the database. This indicates that further efforts are required both on a local and international level, where this is possible, to compile detailed information on SHP projects to have a more complete understanding of the sector. It is hoped that the database can be further expanded in future editions.

Case studies

The case study section of the *WSHPDR 2022* comprises 12 case studies. The case studies share the best practices and experiences from a range of countries, highlighting the potential of SHP for productive use and community development. They demonstrate that SHP plants, when carefully planned and developed respecting the needs of communities and with regard to local capacities, infrastructure and environment, can provide a reliable and affordable source of electricity, revolutionizing the daily lives of communities, in particular in rural areas.

The section aims to provide real-life examples of benefits that communities can receive from SHP as well as the challenges encountered and solutions found during the implementation of SHP projects. Each case study includes a list of lessons learnt summarizing the factors that should be kept in mind while planning, developing and implementing SHP projects in order to ensure their success. This information might be particularly useful for decision-makers, students, engineers and company managers.

The case studies are gathered under the following three themes.

SHP for social and community development: Many people in the world still live without access to affordable, reliable and clean electricity. Lack of electricity is a significant barrier to human, social and community development, specifically impacting vulnerable groups, including women and young people. The case studies presented in this group (Brazil, Ghana, Japan, Kenya, Tanzania and Zambia) demonstrate the benefits that SHP can offer target communities. In particular, the discussed projects created employment opportunities, increased the standard of public service provision, improved security and education conditions. In these cases, SHP helped communities become more autonomous, stimulated local business and entrepreneurship and considerably improved life quality.

Technological solutions for SHP: SHP development and operation can be influenced by different factors, such as market, weather, site location and strict environmental regulations. A range of technical solutions exist that can help adapt the SHP technology to the local conditions and improve the control over different factors, making the SHP management more efficient and predictable. These include retrofitting of existing civil structures (Italy case), developing a compact run-of-river low-head hydropower concept (Hydroshaft), using innovative software solutions such as HYDROGRID's automated data-driven optimization for SHP cascades, intelligent operation control and dispatching systems for complementary power plants (China case), or Fichtner's Hybrid Configurator that helps design hybrid power plants and analyze their technical and financial impact.

Green SHP: Lack of appropriate regulation and control over SHP development can result in significant ecological impact including river dehydration, changed river ecology, reduced river connectivity and affected migratory fish and other aquatic species. Lack of sustainable practices, can also increase the risk of socio-environmental conflicts. To maintain the ecological safety of the sector, the future of SHP development should be in the form of green SHP, supported by regulations, guidelines, incentive policies and practices. The Ukraine case study outlines the importance of SHP construction and operation in line with the principles of ecological sustainability.

Conclusions & Recommendations

SHP is a mature and versatile technology, effective for providing access to clean and sustainable electricity both in the developing and developed world, particularly in rural areas. Through developing SHP, many countries have already taken steps — or are beginning to take steps — to alleviate poverty and increase access to electricity. SHP also helps developed nations achieve targets for advancing renewable energy and reducing greenhouse gas emissions.

The purpose of this edition of the *WSHPDR* is to illustrate the improvements achieved in the SHP sector across regions and the great positive impacts linked to SHP development. Since the publication of the first edition of the Report in 2013, the combined installed capacity of SHP in the world increased by 12 per cent reaching 79 GW. At the same time, known SHP potential is estimated at 221.7 GW. Thus, the data collected in the Report demonstrate that there is still room for improvement in the SHP sector in many parts of the world. Overall, despite the progress made in SHP development in the last few years, many of the barriers and, hence, recommendations for the further development of the sector remain similar to those listed in the previous editions of the Report.

The following recommendations for addressing the barriers to SHP development are provided as general recommendations and should not be considered comprehensive.

(a) Undertake detailed resource assessments

Developing countries should undertake detailed analyses of their SHP potential to lower development costs and encourage private investment. Developed countries would similarly benefit from undertaking detailed re-assessments of their SHP potential, accounting for new technologies, ecological conditions, regulations as well as the potential arising from the conversion of existing infrastructure and the rehabilitation of old sites.

(b) Develop appropriate policies and regulations

Policies and financial incentives already established for other sources of renewable energy should be extended to cover SHP, particularly emphasizing green technology, and clear targets for SHP development should be set. Such policies and incentives should be properly designed to account for the local conditions and draw on collaboration among agencies responsible for water resources, environment and electricity. Government agencies should also streamline the licensing process by creating a one-stop shop for standardized permits and contracts.

(c) Facilitate access to sustainable sources of financing

An overall strategy aiming to reduce the financial risks for investors should be developed. High initial costs need to be overcome with easier and improved access for project developers to be able to successfully provide finance. One measure that can mitigate this is creating awareness of SHP among local banking institutions or microfinance institutions to improve the risk assessment and provide conducive loan conditions.

(d) Facilitate access of the SHP industry to equipment and technology

The building or improvement of industries that serve as components of SHP will aid in the overall development of the SHP sector. In countries with insufficient local technology, access to imports can be aided through the establishment of concessionary duties and reduced import taxes.

(e) Provide reliable infrastructure

Developing robust grids with suitable capacity and coverage to accommodate new connections facilitates connecting SHP plants and is critical for attracting private investment. In countries with high distribution losses, investments in distribution systems should match those in the generation, to raise the overall efficiency of SHP projects. Establishing microgrids with SHP providing base-load power can also offer a short to medium-term—or even permanent—solution for electrifying remote and inaccessible communities.

(f) Improve local skills and expertise

By increasing local capacities in conducting feasibility studies, construction, operation and maintenance of SHP plants, the whole SHP sector can become more self-sufficient and long-lasting for countries.

(g) Strengthen international and regional cooperation

The promotion of SHP by international and regional institutions is essential for mainstreaming SHP as a positive renewable energy solution. On a more specific level, more information is needed on such topics as new SHP technologies, sustainable models for financing and ownership of SHP projects, the effectiveness of financial incentives for SHP development and the impact of the climate crisis on SHP. By developing South-South cooperation and triangular cooperation among developing countries, developed countries and international organizations, international and regional agencies can facilitate the transition of individual pilot SHP projects towards the successful implementation of full-scale SHP programmes.

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Key facts about countries

Africa

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed (≤10 MW)*	*Potential (≤10 MW)*
Algeria	≤10 MW	47.1	N/A	47.1	N/A
Angola	≤10 MW	46.1	600.0	46.1	600.0
Benin	≤30 MW	0.5	95.0	0.5	N/A
Botswana	N/A	0.0	N/A	0.0	1.0
Burkina Faso	N/A	N/A	N/A	5.0	246.0
Burundi	≤1 MW	2.2	30.5	17.4	61.0
Cameroon	≤5 MW	1.5	N/A	1.5	970.0
Central Africa Republic	≤10 MW	18.8	41.0	18.8	41.0
Congo	N/A	N/A	N/A	0.0	70.5
Côte d'Ivoire	≤10 MW	5.0	45.7	5.0	45.7
Democratic Republic of the Congo	≤10 MW	56.0	101.0	56.0	101.0
Egypt	N/A	N/A	N/A	0.0	120.0
Equatorial Guinea	N/A	N/A	N/A	7.5	31.9
Eswatini	N/A	8.2	16.2	8.2	16.2
Ethiopia	≤10 MW	12.9	1,500.0	12.9	1,500.0
Gabon	N/A	N/A	N/A	6.0	518.1
Gambia	≤30 MW	0.0	N/A	0.0	19.5
Ghana	≤1 MW	0.1	9.9	0.1	17.4
Guinea	≤1.5 MW	N/A	N/A	11.2	751.8
Kenya	≤3 MW	N/A	N/A	66.3	3,000.0
Lesotho	≤10 MW	3.8	38.2	3.8	38.2
Liberia	≤30 MW	4.9	592.0	4.9	N/A
Madagascar	N/A	N/A	N/A	37.0	836.0
Malawi	≤5 MW	4.7	150.0	12.9	N/A
Mali	≤30 MW	5.7	154.7	5.7	N/A
Mauritania	N/A	0.0	N/A	0.0	N/A
Mauritius	N/A	N/A	N/A	19.7	19.7
Morocco	≤10 MW	30.5	300.0	30.5	300.0
Mozambique	≤10 MW	4.8	1,000.0	4.8	1,000.0
Namibia	N/A	0.1	120.0	0.1	120.0
Niger	N/A	0.0	N/A	0.0	8.0
Nigeria	≤30 MW	57.2	734.3	N/A	N/A
Réunion	≤10 MW	10.6	16.6	10.6	16.6
Rwanda	≤5 MW	34.4	111.1	N/A	N/A
Sao Tome and Principe	≤10 MW	1.9	63.8	1.9	63.8
Senegal	≤10 MW	0.0	0.0	0.0	0.0
Sierra Leone	≤30 MW	12.2	N/A	12.2	639.0
Somalia	N/A	N/A	N/A	0.0	4.6
South Africa	≤40 MW	N/A	N/A	42.0	247.0
South Sudan	N/A	N/A	N/A	0.0	688.1
Sudan	≤5 MW	N/A	N/A	7.2	2,228.6

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed (≤10 MW)*	*Potential (≤10 MW)*
Tanzania	≤10 MW	30.5	480.0	30.5	480.0
Togo	N/A	N/A	N/A	1.6	137.0
Tunisia	N/A	N/A	N/A	17.0	56.0
Uganda	≤20 MW	186.0	400.0	107.9	214.1
Zambia	≤20 MW	N/A	N/A	18.7	62.0
Zimbabwe	≤30 MW	31.4	N/A	16.1	120.0

Americas

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed (≤10 MW)*	*Potential (≤10 MW)*
Argentina	≤50 MW	510.0	N/A	97.0	430.0
Belize	N/A	N/A	N/A	10.3	21.7
Bolivia	≤5 MW	N/A	N/A	99.1	N/A
Brazil	≤30 MW	6,324.6	35,765.0	1,608.2	3,737.8
Canada	≤50 MW	4,504.0	15,000.0	N/A	N/A
Chile	≤20 MW	618.0	5,145.0	304.0	2,995.0
Colombia	≤20 MW	900.8	N/A	234.6	4,946.0
Costa Rica	N/A	N/A	N/A	126.5	N/A
Cuba	N/A	N/A	N/A	21.0	77.0
Dominica	≤10 MW	6.6	N/A	6.6	N/A
Dominican Republic	≤10 MW	59.7	N/A	59.7	N/A
Ecuador	≤10 MW	112.7	356.3	112.7	356.3
El Salvador	≤5 MW	21.7	N/A	21.7	119.6
French Guiana	≤10 MW	5.5	34.5	5.5	34.5
Greenland	≤5 MW	N/A	N/A	9.0	183.1
Grenada	N/A	N/A	N/A	0.0	7.0
Guadeloupe	≤10 MW	11.6	33.0	11.6	33.0
Guatemala	≤5 MW	123.0	204.9	N/A	N/A
Guyana	≤5 MW	0.02	24.2	0.02	92.0
Haiti	N/A	N/A	N/A	6.8	37.6
Honduras	≤30 MW	288.6	N/A	148.0	385.0
Jamaica	N/A	N/A	N/A	30.6	76.2
Mexico	≤30 MW	699.3	N/A	N/A	N/A
Nicaragua	≤10 MW	26.6	104.7	26.6	104.7
Panama	N/A	N/A	N/A	147.2	263.5
Paraguay	≤50 MW	0.0	116.3	0.0	N/A
Peru	≤20 MW	503.8	3,500.0	N/A	N/A
Puerto Rico	N/A	N/A	N/A	39.3	43.9
Saint Lucia	N/A	N/A	N/A	0.0	2.7
Saint Vincent and the Grenadines	≤10 MW	5.7	7.5	5.7	7.5
Suriname	N/A	N/A	N/A	0.0	2.7
USA	N/A	N/A	N/A	3,681.0	10,583.0
Uruguay	≤50 MW	0.0	231.5	0.0	208.0
Venezuela	N/A	N/A	N/A	1.4	49.7

Asia

Country	Local SHP definition	Installed capacity (local def.)	Potential capacity (local def.)	Installed (≤10 MW)	Potential (≤10 MW)
Afghanistan	≤25 MW	N/A	N/A	83.2	1,200.0
Armenia	≤30 MW	382.0	431.0	340.0	N/A
Azerbaijan	≤10 MW	49.5	520.0	49.5	520.0
Bangladesh	N/A	N/A	N/A	0.0	60
Bhutan	≤25 MW	32.4	23,296.0	8.4	8.9
Cambodia	≤10 MW	1.7	300.0	1.7	300
China	≤50 MW	81,300.0	128,000.0	41,985.0	63,500.0
DPRK	N/A	N/A	N/A	522.1	N/A
Georgia	≤15 MW	263.0	723.9	212.2	491.8
India	≤25 MW	4,787.0	21,134.0	N/A	N/A
Indonesia	≤10 MW	543.0	19,385.0	543.0	19,385.0
Iran	≤10 MW	19.5	90.8	19.5	90.8
Iraq	N/A	N/A	N/A	6.0	62.4
Israel	N/A	N/A	N/A	7.0	N/A
Japan	≤10 MW	3,577.0	10,330.0	3,577.0	10,330.0
Jordan	≤10 MW	12.0	N/A	12.0	N/A
Kazakhstan	≤35 MW	255.0	2,354.4	118.0	1,380.9
Kyrgyzstan	≤30 MW	53.8	N/A	53.8	311.8
Lao PDR	≤15 MW	162.0	2,287.0	N/A	N/A
Lebanon	≤10 MW	31.2	144.8	31.2	144.8
Malaysia	≤30 MW	296.0	1,500.0	N/A	N/A
Mongolia	≤10 MW	4.7	129.5	4.7	129.5
Myanmar	≤10 MW	42.9	114.0	42.9	114.0
Nepal	≤25 MW	662.5	4,000.0	N/A	N/A
Pakistan	≤50 MW	445.0	3,190.0	N/A	N/A
Philippines	≤10 MW	145.0	1,265.0	145.0	1,265.0
Republic of Korea	≤5 MW	N/A	N/A	199.5	1,500.0
Saudi Arabia	N/A	N/A	N/A	0.0	130.0
Sri Lanka	≤10 MW	425.0	873.0	425.0	873.0
Syria	≤10 MW	23.0	67.6	23.0	67.6
Tajikistan	≤30 MW	142.1	N/A	54.7	30,000.0
Thailand	≤6 MW	190.4	700.0	N/A	N/A
Timor-Leste	≤50 MW	0.4	N/A	0.4	219.8
Turkey	≤10 MW	1,662.2	4,891.5	1,662.2	4,891.5
Turkmenistan	N/A	N/A	N/A	1.2	1,300.0
Uzbekistan	≤30 MW	303.6	1,392.0	87.8	N/A
Viet Nam	≤30 MW	3,600.0	7,200.0	N/A	N/A

Europe

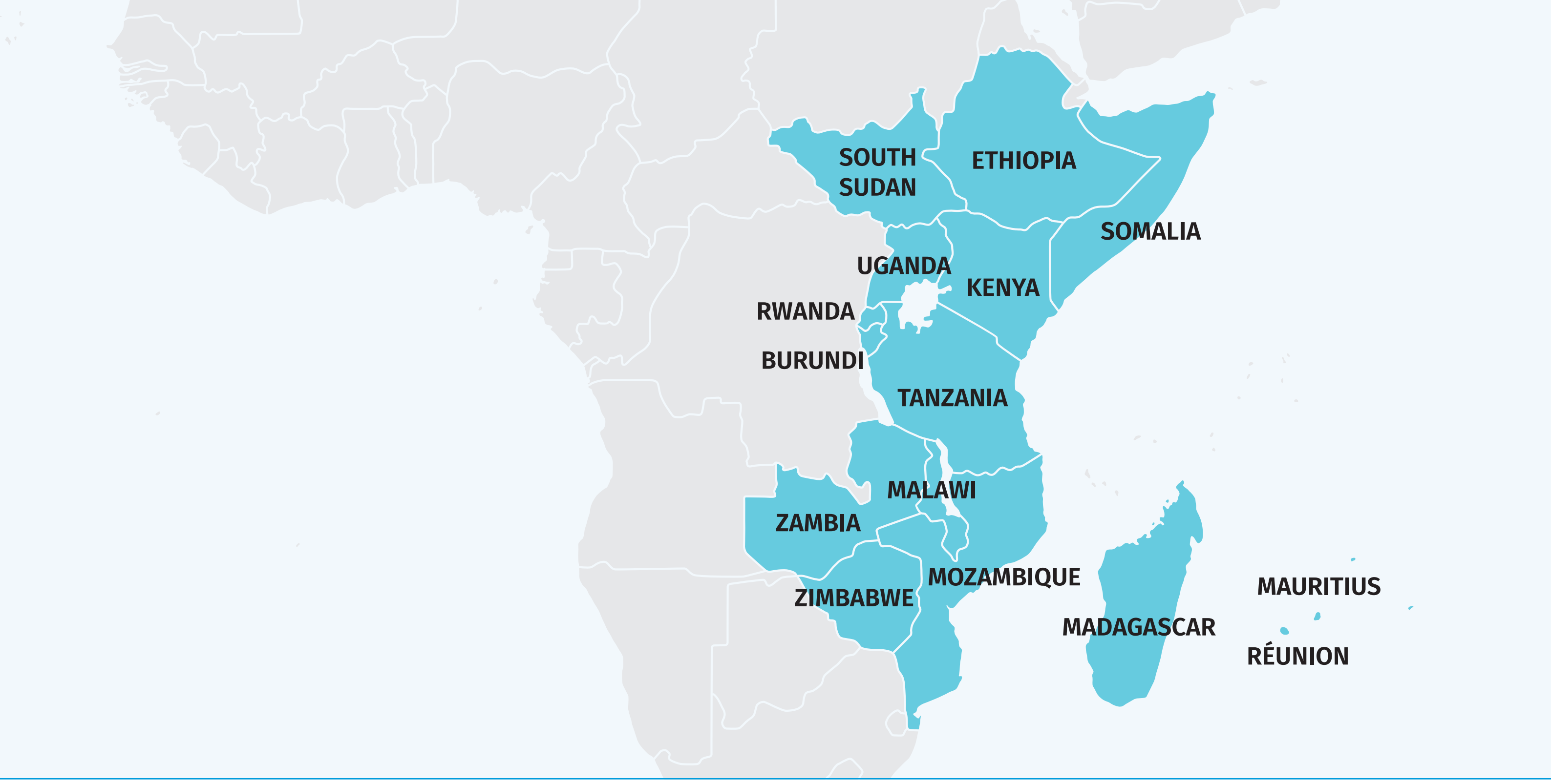
Country	Local SHP definition	Installed capacity (local def.)	Potential capacity (local def.)	Installed (≤10 MW)	Potential (≤10 MW)
Austria	≤10 MW	1,521.6	1,780.0	1,521.6	1,780.0
Albania	≤15 MW	482.0	N/A	432.0	1,963.0
Belarus	≤10 MW	17.3	250.0	17.3	250.0
Belgium	≤10 MW	76.0	103.4	76.0	103.4
Bosnia & Herzegovina	≤10 MW	172.2	1,005.0	172.2	1,005.0

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed (≤10 MW)*	*Potential (≤10 MW)*
Bulgaria	N/A	N/A	N/A	494.7	580.7
Croatia	≤10 MW	45.7	100.0	45.7	100.0
Czech Republic	≤10 MW	353.0	465.0	353.0	465.0
Denmark	≤10 MW	7.0	9.8	7.0	9.8
Estonia	≤10 MW	8.0	10.0	8.0	10.0
Finland	≤10 MW	297.5	585.5	297.5	585.5
France	≤10 MW	2,200.0	2,615.0	2,200.0	2,615.0
Germany	N/A	N/A	N/A	1,674.0	1,830.0
Greece	≤15 MW	247.2	2,000.0	N/A	N/A
Hungary	≤5 MW	17.1	28.0	N/A	N/A
Iceland	≤10 MW	66.1	3,742.0	66.1	3,742.0
Ireland	≤10 MW	58.5	70.7	58.5	70.7
Italy	≤10 MW	3,648.4	7,073.0	3,648.4	7,073.0
Latvia	≤10 MW	28.0	96.0	28.0	96.0
Lithuania	≤10 MW	26.9	57.9	26.9	57.9
Luxembourg	≤10 MW	25.3	44.0	25.3	44.0
Moldova	N/A	N/A	N/A	0.3	7.2
Montenegro	≤10 MW	34.7	97.5	34.7	97.5
Netherlands	≤10 MW	13.0	N/A	13.0	N/A
North Macedonia	≤10 MW	111.4	258.0	111.4	258.0
Norway	≤10 MW	2,924.0	7,162.0	2,924.0	7,162.0
Poland	N/A	N/A	N/A	291.7	1,500.0
Portugal	≤10 MW	415.0	750.0	415.0	750.0
Romania	≤10 MW	321.0	730.0	321.0	730.0
Russia	≤30 MW	852.9	825,844.6	168.4	N/A
Serbia	≤30 MW	N/A	N/A	109.0	N/A
Slovakia	≤10 MW	81.6	145.0	81.6	145.0
Slovenia	≤1 MW	N/A	N/A	164.0	180.0
Spain	≤10 MW	2,145.0	2,158.0	2,145.0	2,158.0
Sweden	≤10 MW	961.0	N/A	961.0	N/A
Switzerland	≤10 MW	1,000.0	1,500.0	1,000.0	1,500.0
Ukraine	≤10 MW	119.6	280.0	119.6	280.0
United Kingdom	≤10 MW	405.0	1,179.0	405.0	1,179.0

Oceania

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed (<10 MW)*	*Potential (≤10 MW)*
Australia	≤10 MW	175.0	N/A	175.0	N/A
Federated States of Micronesia	N/A	N/A	N/A	0.7	9.0
Fiji	≤10 MW	11.3	43.2	11.3	43.2
French Polynesia	≤10 MW	48.6	98.0	48.6	98.0
New Caledonia	≤10 MW	13.0	100.0	13.0	100.0
New Zealand	≤50 MW	475.0	N/A	146.8	489.8
Papua New Guinea	≤10 MW	41.0	153.0	41.0	153.0
Samoa	N/A	N/A	N/A	15.5	22.0
Solomon Islands	N/A	N/A	N/A	0.4	11.0
Vanuatu	N/A	N/A	N/A	1.3	5.4

1. Africa



1.1. Eastern Africa

Countries: Burundi, Ethiopia, Kenya, Madagascar, Malawi, Mauritius, Mozambique, Réunion, Rwanda, Somalia, South Sudan, Tanzania, Uganda, Zambia, Zimbabwe

INTRODUCTION TO THE REGION

Countries comprising the Eastern Africa region are highly diverse in terms of geography, population dynamics and socio-economic conditions, with the regional electricity sector development reflecting this diversity. Access to electricity in the region ranges from 100 per cent in Mauritius to 7 per cent in South Sudan, which is also the lowest rate of electricity access in the world. Across other countries in Eastern Africa, access to electricity in the region averages below 50 per cent and displays significant disparities between urban and rural areas.

The main sources of electricity generation in Eastern Africa are thermal power and hydropower. Renewable energy sources other than hydropower are most widely represented by solar power, which exists in nearly all countries of the region but contributes a relatively small share of generated electricity. Kenya is the regional leader in geothermal power and, along with Ethiopia, employs considerable wind power capacities. Bioenergy from a variety of sources, including bagasse and bioethanol, is a widespread form of supplementary electricity generation in the region and accounts for a significant share of installed capacity in Réunion, Ethiopia, Malawi, Mozambique, Tanzania and Zimbabwe.

The role of hydropower in Eastern Africa is very significant, although installed and potential hydropower capacities vary widely by country. The regional leaders in hydropower generation are Ethiopia, Mozambique and Zambia. Hydropower is the largest single source of electricity generation in these three countries and additionally in Burundi, Malawi, Rwanda, Uganda and Zimbabwe. In Kenya, Madagascar, Mauritius, Réunion and Tanzania, hydropower is an important but supplementary source of electricity generation. There is no operational hydropower capacity in Somalia and South Sudan, although Somalia retains at least one major hydropower plant that is currently out of service.

An overview of the electricity sectors of the countries in the region is provided in Table 1.

Table 1. Overview of Eastern Africa

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Burundi	12	12	4	88	346	50	178
Ethiopia	115	51	30	4,817	14,553	4,071	13,655
Kenya	54	75	52	2,840	11,467	834	4,233
Madagascar	27	20	12	861	1,370	163	664
Malawi	19	11	4	574	1,887	394	N/A
Mauritius	1	100	100	844	2,882	60	116
Mozambique	32	31	4	2,915	15,603	2,204	14,826
Réunion	1	N/A	N/A	903	2,978	133	423
Rwanda	13	67	N/A	210	821	95	397
Somalia	15	35	15	106	N/A	0	0
South Sudan	11	7	6	175	581	0	0
Tanzania	58	38	19	1,764	7,594	581	N/A
Uganda	44	41	32	1,347	4,414	1,073	4,032
Zambia	18	43	14	2,981	15,040	2,399	12,332
Zimbabwe	15	48	28	2,431	9,351	1,081	5,504
Total	-	-	-	**22,856**	-	**13,139**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

Countries in Eastern Africa adhere to different definitions of small hydropower (SHP). The up to 10 MW definition is the most common and has been adopted by Ethiopia, Mozambique, Réunion and Tanzania. Malawi and Rwanda use the up to 5 MW definition, while Uganda and Zambia adhere to the up to 20 MW definition. Finally, SHP is defined as up to 1 MW in Burundi, up to 3 MW in Kenya and up to 30 MW in Zimbabwe. No official definition of SHP exists in Madagascar, Mauritius, Somalia and South Sudan.

A comparison of installed and potential SHP capacities in the Eastern Africa region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Eastern Africa (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Burundi	Up to 1 MW	2.2	30.5	17.4	61.0
Ethiopia	Up to 10 MW	12.9	1,500.0	12.9	1,500.0
Kenya	Up to 3 MW	N/A	N/A	66.3	3,000.0
Madagascar	N/A	N/A	N/A	37.0	836.0
Malawi	Up to 5 MW	4.7	150.0	12.9	150.0*
Mauritius	N/A	N/A	N/A	19.7	19.7
Mozambique	Up to 10 MW	4.8	1,000.0	4.8	1,000.0
Réunion	Up to 10 MW	10.6	16.6	10.6	16.6
Rwanda	Up to 5 MW	34.4	111.1	34.4*	111.1*

Country	Local SHP definition	Installed capacity (local def.)	Potential capacity (local def.)	Installed capacity (≤10 MW)	Potential capacity (≤10 MW)
Somalia	N/A	N/A	N/A	0.0	4.6
South Sudan	N/A	N/A	N/A	0.0	688.1
Tanzania	Up to 10 MW	30.5	480.0	30.5	480.0
Uganda	Up to 20 MW	186.0	400.0	107.9	214.1
Zambia	Up to 20 MW	N/A	N/A	18.7	62.0
Zimbabwe	Up to 30 MW	31.4	N/A	16.1	120.0
Total	**-**	**-**	**-**	**389.1**	**8,263.2**

Source: *WSHPDR 2022*[1]

Note: *Based on the local definition of SHP.

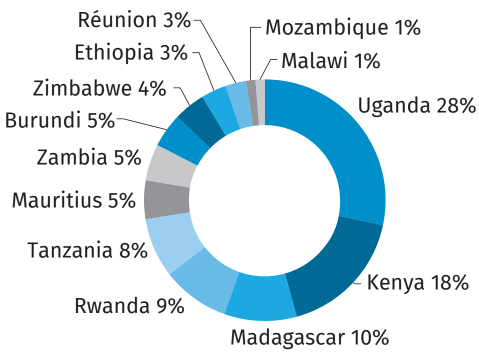
The total installed capacity of SHP up to 10 MW in Eastern Africa is at least 389.1 MW, while total potential capacity is estimated at 8,263.2 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has increased by 41 per cent both due to ongoing SHP development in the region and access to better data on previously-existing plants. The potential capacity has increased by 21 per cent, largely as a result of a re-evaluation of SHP potentials in Madagascar and South Sudan.

SHP is a widespread source of electricity generation across much of Eastern Africa with the exception of Somalia and South Sudan and is commonly utilized for electrification of remote population centres as well as off-grid agro-industrial facilities including tea factories and multi-use facilities such as missions. SHP accounts for 23 per cent of all installed hydropower capacity in Madagascar, 33 per cent in Mauritius, 36 per cent in Rwanda and 39 per cent in Burundi, while hydropower capacities in other countries in the region are heavily dominated by large-scale plants.

Activity in the SHP sector in the region is uneven, with some countries actively pursuing SHP development and others prioritizing other renewable energy sources. In recent years, construction of new SHP plants has been most active in Uganda, Kenya, Madagascar, Rwanda and Zambia, while in other countries in the Eastern Africa region little new SHP development has taken place and changes in reported installed capacity are generally accounted for by more precise data on previously-existing SHP plants. Additionally, SHP development and planning in parts of the region is hampered by political and economic instability.

The national share of regional installed SHP capacity up to 10 MW by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

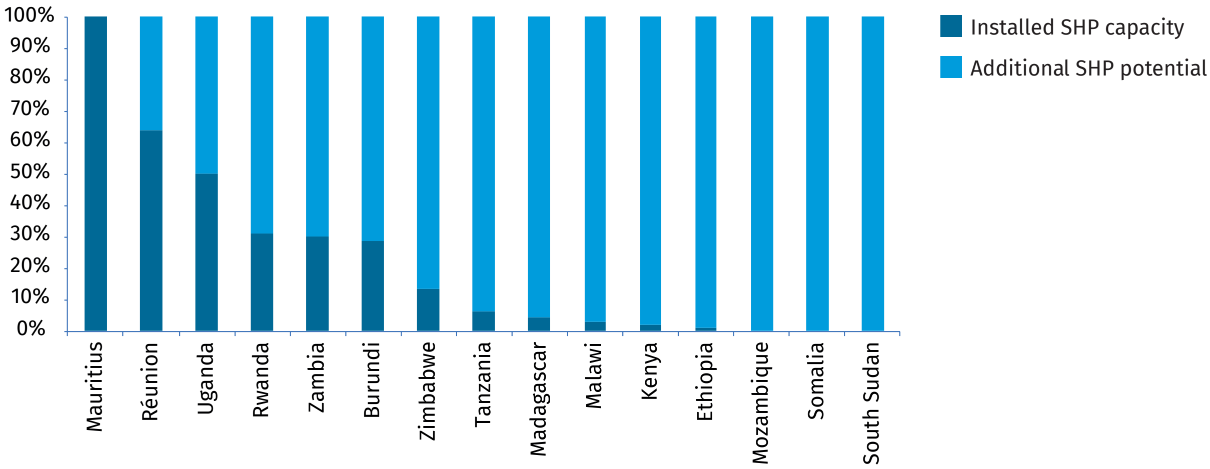
Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Eastern Africa (%)**



Source: *WSHPDR 2022*[1]

Note: Somalia and South Sudan are not included due to lack of installed SHP capacity.

Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Eastern Africa (%)**



Source: *WSHPDR 2022*[1]

The installed SHP capacity up to 1 MW in **Burundi** is 2.2 MW, while the estimated potential capacity is 30.5 MW, indicating that 7 per cent has been developed. For SHP up to 10 MW, installed and estimated potential capacities are 17.4 MW and 60 MW, respectively, indicating that 29 per cent has been developed. While no new SHP plants have been commissioned in recent years, two SHP projects with a cumulative capacity of 9.1 MW were in the planning stages as of 2021.

In **Ethiopia**, the installed capacity of SHP up to 10 MW is 12.9 MW, while potential capacity is estimated at 1,500 MW, indicating that less than 1 per cent has been developed. While Ethiopia is in the process of expanding its already considerable large hydropower capacity, the SHP sector in the country has seen little development in the last few years and there are no plans for the construction of any additional SHP plants in the near future.

The installed capacity for SHP up to 10 MW in **Kenya** is 66.3 MW, while potential capacity has been estimated at 3,000 MW, indicating that approximately 2 per cent has been developed. The country has actively pursued SHP development, with a large number of plants operated by the Kenya Tea Development Authority (KTDA) to support the operation of tea processing facilities. More than 260 potential SHP sites have been identified in studies carried out over the last decade, with the highest concentration of potential sites located in the Tana River basin. Many new SHP projects are either under construction or in the planning stages, with the KTDA continuing to play a key role in SHP development in the country.

The installed capacity of SHP up to 10 MW in **Madagascar** is 37 MW. The estimate of potential capacity, updated on the basis of a 2017 study, is 836 MW, suggesting that 4 per cent has been developed. SHP development in the country is actively on-going, with several new plants commissioned between 2019 and 2021 and three SHP projects under development as of 2021.

In **Malawi**, the installed capacity for SHP up to 5 MW is 4.7 MW, while potential capacity is estimated at 150 MW, indicating that 3 per cent has been developed. Recent activity in the SHP sector has included major reconstruction of existing SHP plants, with the total installed capacity of SHP up to 5 MW actually decreasing as several ageing plants were replaced by a newer SHP plant with an installed capacity of 8.25 MW in 2020. Consequently, the installed capacity for SHP up to 10 MW in the country reached 12.9 MW. Two additional ongoing SHP projects with a total capacity of 9.5 MW have passed the feasibility study stage.

Mauritius has an installed capacity of 19.69 MW for SHP up to 10 MW. No additional undeveloped potential has been identified, suggesting that the country's SHP potential is fully utilized. The most recently-constructed SHP plant was commissioned in 2019, but most of the country's SHP fleet is old and requires refurbishment. A government study has been launched to assess the existence of additional undeveloped potential.

The installed capacity for SHP up to 10 MW in **Mozambique** is 4.8 MW, while potential is estimated at 1,000 MW, indicating that less than 1 per cent has been developed. Little SHP development has taken place in the country over the last decade, as activity in the hydropower sector has been focused on large hydropower projects. The largest concentration of SHP plants in Mozambique is located in the central parts of the country and most existing plants have an installed capacity under 1 MW. Recent in-depth studies have identified hundreds of potential SHP sites across the country with a combined potential capacity of over 672 MW.

The installed capacity for SHP up to 10 MW in **Réunion** is 10.6 MW, with an additional 6 MW of untapped potential. The total estimated potential capacity in the country is thus 16.6 MW, of which 64 per cent has been developed. The last SHP plant in the country was commissioned in 2018. A number of additional SHP projects are in the planning stage, all with capacities under 1 MW.

In **Rwanda**, the installed capacity for SHP up to 5 MW is 34.4 MW, while the potential capacity is estimated at 111.1 MW, indicating that 31 per cent has been developed. The country has seen active SHP development in recent years, with several new plants commissioned between 2017 and 2020. Likewise, 10 additional plants are expected to become operational by 2024.

Somalia has no operational SHP capacity, although the existence of one previously operational SHP plant suggests a potential capacity of at least 4.6 MW if the plant were to be refurbished or rebuilt. The SHP sector in the country is stagnant, although plans to rehabilitate the existing SHP infrastructure in the country have been announced by the Government in a 2016 report.

South Sudan likewise has no operational SHP capacity. However, the potential capacity for SHP up to 10 MW is considerable, estimated at 688.1 MW in a 2018 study. There are no known plans for SHP development in the country on the national level and the country overall lacks a comprehensive renewable energy framework. Existing plans for renewable energy development focus on solar power projects and large hydropower.

The installed capacity for SHP up to 10 MW in **Tanzania** is 30.5 MW, while potential is estimated at 480 MW, indicating that approximately 6 per cent has been developed. The country has over 1,600 SHP plants, most of which are operated by faith-based groups for the provision of power to community facilities and health centres. Several SHP plants with capacities below 1 MW were commissioned between 2017 and 2019 and at least four different studies have identified hundreds of potential SHP sites across the country.

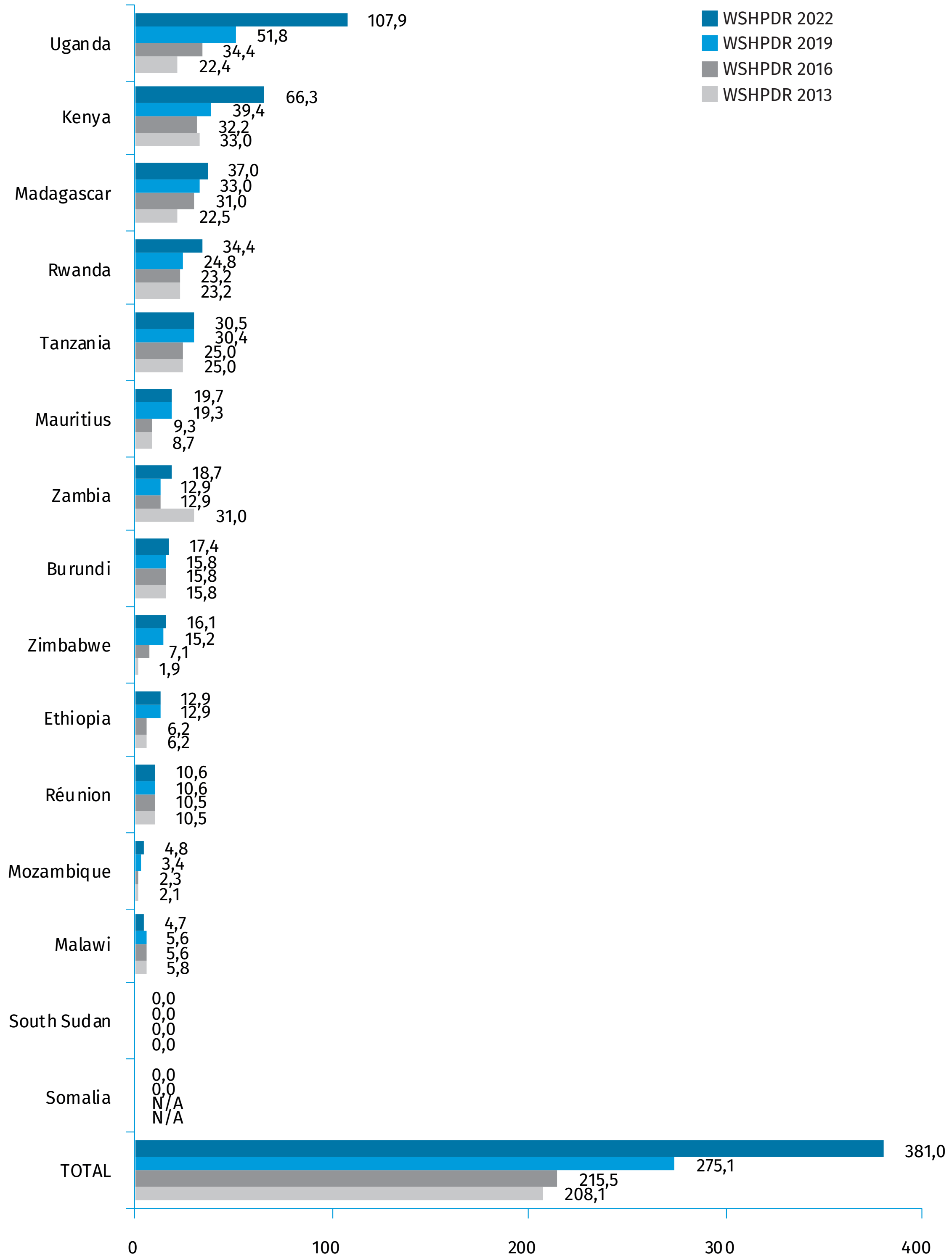
Uganda leads the Eastern Africa region in installed SHP capacity. The installed capacity of SHP up to 20 MW in the country is 186 MW, while estimated potential is 400 MW, indicating that 47 per cent has been developed. For SHP up to 10 MW, the installed capacity is 107.9 MW and estimated potential is 214.1, indicating that 50 per cent has been developed. SHP development in the country is very active, with over a dozen SHP plants up to 20 MW constructed between 2017 and 2022. Seventeen additional SHP projects were under construction as of 2022 and 20 potential SHP sites have been identified in various parts of the country.

The installed capacity of SHP up to 10 MW in **Zambia** is 18.7 MW, while the potential capacity is estimated at 62 MW, indicating that 30 per cent has been developed. The installed SHP capacity of the country has increased substantially due to the commissioning of two new SHP plants in 2020 with a combined capacity of 10.6 MW. In addition to new stream development, older SHP plants have either undergone refurbishment and capacity upgrades or have been decommissioned and replaced with new plants. Several SHP projects were in various stages of development as of 2020.

The installed capacity of SHP up to 10 MW in **Zimbabwe** is 16.1 MW, while the estimated potential capacity is 120 MW, indicating that approximately 12 per cent has been developed. For SHP up to 30 MW, the installed capacity is 31.4 MW, although no estimate of potential capacity is available. SHP plants in Zimbabwe are employed either as grid-connected facilities, which are operated by private companies, or as off-grid systems owned by communities and supported by non-governmental organizations (NGOs). One new SHP plant was commissioned in Zimbabwe in 2018 and several additional SHP projects are under construction.

Changes in the installed SHP capacities of countries in the region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in Eastern Africa (MW)**



Source: *WSHPDR 2022,*[1] *WSHPDR 2013,*[2] *WSHPDR 2016,*[3] *WSHPDR 2019*[4]

Note: For SHP up to 10 MW with the exception of Malawi, where the local definition of SHP is used for consistent comparison with previous editions of the *WSHPDR*.

Climate Change and Small Hydropower

Almost half of the installed SHP capacity of Africa is located in Eastern Africa, with over 55 per cent of regional SHP capacity located in the Nile River basin. Climate change impacts on SHP in the region vary significantly depending on the models used. Projected variability in rainfall patterns and changes in temperature are likely to threaten water supply and storage, and pose a challenge to electricity generation in countries highly reliant on hydropower. A particular risk is a potential future decrease in wet season precipitation across the region. At the same time, expected increases in precipitation and runoff in certain parts of Eastern Africa can present an opportunity for SHP development. For example, some watersheds in Tanzania could see an increase in runoff of 160 per cent. Finally, climate change is expected to impact the reliability of estimates of hydropower potential in the region and the feasibility of previously identified sites. Consequently, older estimates of SHP potential in regional countries may no longer be accurate.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The development of SHP in **Burundi** is hampered by the lack of funds, local expertise in the SHP sector and limited hydrological data. At the same time, the country has a considerable untapped SHP capacity, with a range of potential sites already identified.

The main barrier to SHP development in **Ethiopia** is the Government's focus on large hydropower, which has resulted in a lack of funding for SHP as well as a lack of detailed and up-to-date information on potential SHP sites in the country. Ongoing political instability has been another factor holding back SHP projects. On the other hand, several recent government initiatives may be conducive to SHP development in the future, including a directive simplifying licensing for power generation on mini-grids and initiatives targeting rural electrification. The country's large untapped SHP potential suggests the country could considerably expand its overall generation capacity through SHP development.

Despite a robust and active SHP sector, SHP projects in **Kenya** face long lead times, high upfront costs and a lack of coordination between various government agencies responsible for SHP policy and oversight. More generally, climate change vulnerability and conflicts over land use present additional barriers to the implementation of SHP projects. However, SHP in Kenya also benefits from incentives including tax exemptions and feed-in tariffs (FITs), as well as from a well-established regulatory framework for public-private partnerships. Finally, the country's large undeveloped SHP potential is mapped in several recent studies.

Barriers to SHP development in **Madagascar** include a lack of funding opportunities, lack of local manufacturing capacity for turbines and risks induced by climate change. Enabling factors include the updated assessment of SHP potential in the country, which suggests the feasibility of SHP development on a greater scale than previously estimated, as well as the competitive per kWh cost of SHP in the country relative to other renewable energy sources.

SHP development in **Malawi** faces several significant obstacles including a lack of funding, lack of human capacity in the SHP sector and lack of awareness on the benefits of SHP among local communities. In addition, the SHP sector in the country is under pressure from environmental degradation, the vulnerability of old electrical infrastructure to extreme weather events, and vandalism of physical assets. At the same time, the demand for additional generation capacities is very high in Malawi due to low electricity access, and the existing untapped SHP potential in the country is well-studied. The Government provides certain tax exemptions for SHP projects and financing mechanisms for SHP are also available.

In **Mauritius**, the main obstacle for SHP development is the lack of identified undeveloped SHP potential. Government studies are underway to determine if undeveloped potential exists in the country, which could enable additional development in the SHP sector. Refurbishment of ageing SHP plants could present an additional opportunity for investment.

The development of SHP in **Mozambique** is hampered by the lack of a consolidated legal framework and the absence of an SHP-specific investment strategy, as well as the lack of locally-produced technology in the SHP sector. At the same time, the largely untapped and well-studied SHP potential in the country presents an important opportunity for meeting the electricity needs of remote and rural communities.

A major barrier to SHP development in **Réunion** is the island's isolated location, which significantly raises the cost of projects. Additional barriers unique to the island are its status as a World Heritage Site, volcanic activity and vulnerability to severe weather, all of which also contribute to raising the costs of SHP development. One promising direction for future SHP development in Réunion is the construction of SHP facilities on existing water supply infrastructure, which would minimize the impact of some of the aforementioned barriers.

Barriers to SHP development in **Rwanda** include the high cost of construction caused by difficult topography, geographic isolation and lack of local manufacturing capacity for SHP components, as well as unstable hydrological conditions. Enablers include the compatibility of SHP with micro-grids using other forms of renewable energy, suitable conditions for run-of-river plant construction and the Government's commitment to a climate-resilient model of development.

The main barrier to SHP development in **Somalia** is the ongoing political instability and fragmentation in the country, which severely complicates any development work. Additional barriers include the lack of financing from the private sector, local technical capacity in SHP and the limited regulation and oversight of the electricity sector. The main opportunity in the SHP sector in Somalia is the potential rehabilitation of the formerly operational 4.6 MW SHP plant.

The development of SHP in **South Sudan** is likewise hampered by political and economic instability, as well as by a focus on the development of fossil fuel-fired power plants, large hydropower and solar power. The main enabler for future development in the SHP sector is the country's large and fully undeveloped estimated SHP potential. SHP plants could be employed to at least partially address the problem of electricity access in the country, particularly in rural areas.

In **Tanzania**, barriers to SHP development include the lack of financing for projects as well as the problems with long-term financial sustainability of projects funded by NGOs, as the local customers are unable to bear the financial burden of power development and maintenance. SHP projects are also adversely impacted by issues with long-term planning and the lack of local technical expertise in the SHP sector. On the other hand, the country's large untapped SHP potential has been extensively studied and the country can lean on extensive experience in SHP project implementation. Additionally, Government policy is supportive of off-grid generation, and renewable energy sources including SHP plants are incentivized with standardized power purchase tariffs.

Despite a rapid pace of development, the SHP sector in **Uganda** is hampered by several obstacles, including deficiencies in the quality of the transmission and distribution network, limited local manufacturing capacity, a lengthy and bureaucratic process of land acquisition for projects and poor implementation of environmental oversight. Despite these issues, SHP development in the country is supported by a conducive regulatory environment and incentives for power generation from SHP, including several categories of FITs, in addition to other forms of government support and long-term planning, particularly with regard to using SHP to extend electricity access to rural communities.

Barriers to SHP development in **Zambia** are multi-faceted and include a lack of accurate hydrological data, lack of a comprehensive energy policy, issues with power transmission, financing and incentivization of investments through tariffs. The poor quality of the road network creates additional complications in accessing potential SHP sites. On the other hand, the country has a stable and growing market for electricity with steadily increasing demand, as well as an array of economic and fiscal incentives for SHP development including several categories of FITs, tax incentives, risk cost sharing and subsidies.

In **Zimbabwe**, barriers to SHP development include extreme weather conditions, lack of standard FITs and procurement methods, high cost of local financing coupled with lack of access to foreign financing opportunities and the lack of local manufacturing capacity for SHP equipment. The primary enablers of SHP development in the country are the substantial undeveloped SHP potential and the availability of net metering for SHP projects.

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Burundi

Willy Ciza, Ministry of Hydraulics, Energy and Mines

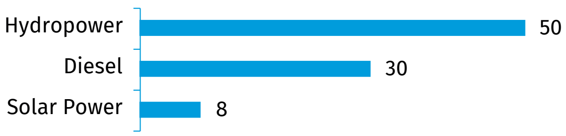
KEY FACTS

Population	12,255,429 (2021)[1]
Area	27,834 km^2 [2]
Topography	The terrain of Burundi is dominated by plateaus and mountains. Plains are only found along the Ruzizi River, north of Lake Tanganyika, forming the border with the Democratic Republic of the Congo. In the west of the country, mountain ranges run from north to south, culminating at Mount Heha, which reaches 2,670 metres above sea level.[2]
Climate	The climate is equatorial, with temperatures ranging according to altitude, from 12 °C at high altitudes in the western mountainous areas to 32 °C in the plains, near Lake Tanganyika and at the Ruzizi River Plain. The capital city of Bujumbura experiences an average annual temperature of 23 °C.[2]
Climate Change	The key climate change impacts experienced by Burundi include increased heavy rainfall, leading to floods and soil erosion; precipitation reduction and long periods of drought, resulting in reduced water resources; increased heat and more frequent extreme weather events. In 1991–2020 the mean temperature was 0.5 °C higher than in the 1971–2000 period and almost 1 °C higher than in 1951–1980. Conversely, mean precipitation reduced, decreasing by an average of 7 mm per decade over the 1951–2020 period.[3]
Rain Pattern	The wet season in Burundi lasts from October to April and the dry season from May to September. Annual precipitation varies by region, ranging from 800–1,000 mm in the north-east to 1,600–2,000 mm at higher elevations in the mountains.[4]
Hydrology	The four major rivers are the Kanyaru, Malagarasi, Rusizi and Ruvubu. The largest lakes are Tanganyika, Cohoha and Rweru.[5]

ELECTRICITY SECTOR OVERVIEW

In 2022, the total installed capacity of Burundi was approximately 88 MW, which consisted of approximately 50 MW of hydropower, 30 MW from a diesel-fired power plant and 7.5 MW from one solar power plant (Figure 1).[6,7,8,9] Additionally, Burundi imports 15.5 MW from the regional Ruzizi hydropower complex located on the border between the Democratic Republic of the Congo and Rwanda.

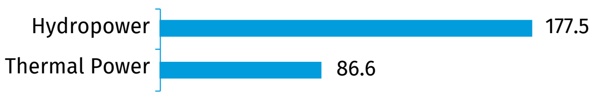
Figure 1. **Installed Electricity Capacity by Source in Burundi in 2022 (MW)**



Sources: Ciza,[6] Nsabimana,[7] Anadolu Agency,[8] REPP[9]

In 2020, electricity generation by the state-owned company Directorate for Production and Distribution of Water and Electricity (REGIDESO) amounted to 264 GWh, of which hydropower accounted for 67 per cent (Figure 2).[10] REGIDESO owns the majority of the electricity generation capacity in the country, however, besides its plants there are also plants owned by the Rural Electrification Agency (ABER) and independent power producers (IPPs). Total electricity generation in the country in 2020 including all producers amounted to 346.3 GWh, however, a breakdown by source for this total is not available.[11]

Figure 2. **Annual Electricity Generation by Source in Burundi in 2020 (GWh)**



Source: ISTEEBU[10]

Note: Includes only generation by REGIDESO.

The World Bank reports an almost 12 per cent national electricity access rate and less than 4 per cent in rural areas.[12,13] However, no studies to determine the electricity access rate in the country have been carried out and these values should be considered as indicative. Overall, electricity supply critically lags behind demand. The Government of Burundi has implemented the policies and regulations to improve the country's energy sector, with a particular focus on renewable energy sources. The goal is to develop the economy, reduce poverty and create more opportunities for income generation from the energy sector.

In order to improve electricity access, a number of projects are currently under development, including, the 49 MW Jiji-Murembwe, 20 MW Kaburantwa and 10.4 MW Mpanda hydropower plants.[7] The plants most recently added to the country's generation fleet include the 7.5 MW solar plant in Mubuga and the 15 MW Ruzibazi hydropower plant in the south of Bujumbura.[8,9] In rural areas, the Government has set up two projects, Soleil Nyakiriza and Umuco w'Iterambere, in order to increase the rate of access to electricity, mainly for public infrastructure (health centre and secondary school) and to create a market for solar equipment in Burundi.

The electricity transmission system in Burundi is made up of 750 kilometres of 110 kV high-voltage lines and 30 kV medium-voltage lines.[14] Due to its dilapidated state, the electricity network does not support the load that passes through it, which leads to blackouts and electricity shortages. Studies are being finalized to rehabilitate the electricity network, mainly in the city of Bujumbura.

The Government of Burundi has opened the country's energy sector to private actors through the liberalization of the renewable energy sector. Investors can participate in electricity production, transportation and distribution as well as carry out marketing activities for the electricity produced. REGIDESO manages the electricity transmission and distribution infrastructure throughout the country, therefore, it acts as the buyer for projects undertaken within the public-private partnership (PPP) framework. For isolated power plants, a legal framework is in place to facilitate customer connection and electricity sales.

Electricity tariffs in Burundi were established in 2017 and are uniform on the entire territory of the country with differentiation according to the customer type (Table 1).[15]

Table 1. **Electricity Tariffs in Burundi**

Type of consumption	*Tariff (FBU/kWh (USD/kWh))*	*Fixed charge (FBU/Month (USD/kWh))*
Households (0–50 kWh)	82 (0.047)	0 (0)
Households (51–150 kWh)	290 (0.166)	0 (0)
Households (≥151 kWh)	546 (0.312)	6,822 (3.898)
Commercial (0–100 kWh)	195 (0.112)	4,122 (2.355)
Commercial (101–250 kWh)	313 (0.179)	8,266 (4.723)
Commercial (≥251 kWh)	399 (0.228)	12,398 (7.085)
Administration	313 (0.179)	11,500 (6.571)

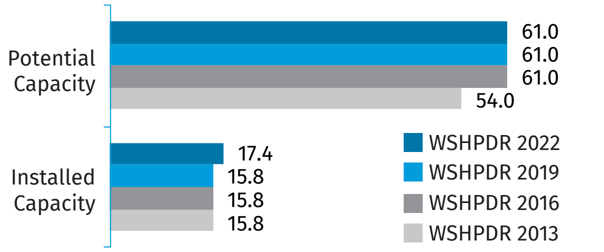
Source: Agence Bujumbura News[15]

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) is defined in Burundi as hydropower plants with capacity of up to 1 MW.

According to the local definition, there are 16 SHP plants in the country with a combined installed capacity of 2.2 MW (Table 2) and an annual generation of 76 GWh.[6] The potential of SHP up to 1 MW is estimated at 30.5 MW.[16] Following the up to 10 MW definition of SHP, the installed capacity of Burundi is 17.39 MW, while the potential, as determined based on planned SHP projects, is 61 MW.[6,16] The changes in installed capacity compared to the *World Small Hydropower Development Report (WSHPDR) 2019* are based on more accurate estimates, whereas the potential estimates have remained unchanged (Figure 3). No new SHP projects have been launched since the previous edition of the report; however, a number of projects are planned as part of the country's efforts to advance the renewable energy sector, including the 300 kW Karonke plant and the 8.8 MW cascade at Dama.[4]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Burundi (MW)**



Sources: Ciza,[6] *WSHPDR 2019*,[16] *WSHPDR 2013*,[17] *WSHPDR 2016*[18]

Note: Data for SHP up to 10 MW.

Table 2. **List of Existing Small Hydropower Plants up to 1 MW in Burundi**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Kayongozi	Ruyigi	0.500	ABER	2013
Mutumba	Bujumbura	0.092	Private	2009
Kiganda	Muramvya	0.043	Private	1990
Butezi	Ruyigi	0.234	ABER	1987
Nyabikere	Karuzi	0.138	ABER	1986
Murore	Cankuzo	0.023	ABER	1985
Buhiga	Karuzi	0.232	REGIDESO	1984
Mpinga	Rutana	0.020	Private	1983
Kigwena	Bururi	0.067	ABER	1982
Ryarusera	Muramvya	0.029	ABER	1982
Musongati	Rutana	0.015	Private	1981
Kiremba	Ngozi	0.068	Private	1980
Teza	Muramvya	0.418	Private	1979
Masango	Cibitoke	0.029	Private	1977
Burasira	Gitega	0.032	Private	1961
Nyamyotsi	Muramvya	0.300	Private	N/A

Source: Ciza,[6] Nsabimana[7]

The total hydropower potential in the country has been estimated to be approximately 1,700 MW, of which approximately 300 MW is economically viable.[19] Table 3 shows a list of selected potential sites identified for SHP development in the country.

Table 3. **List of Selected Potential Small Hydropower Sites in Burundi**

Name	*Location*	*Potential capacity (MW)*	*Type of side (New/refurbishment)*
RUVU197	Shombo	8.400	New
RUVU203	Bugendana	6.900	New
NYKI032	Itaba	6.844	New
SIKU011	Bururi	6.636	New
DAMA015_ATL	Burambi	6.091	New

Source: Ciza[6]

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

Table 4 shows a list of selected SHP projects available for investment.

Table 4. **List of Selected Small Hydropower Projects Available for Investment in Burundi**

Name	*location*	*Capacity (MW)*	*Developer*	*Development stage*
Kagu 006	Cibitoke	6.0	Ministry of Hydraulics, Energy and Mines	Preliminary study
Dama	Rumonge	8.0	Ministry of Hydraulics, Energy and Mines	Preliminary study
Muyo	Rutana	7.0	Ministry of Hydraulics, Energy and Mines	Preliminary study
Musas	Rutana	0.3	Ministry of Hydraulics, Energy and Mines	Preliminary study
Nyen	Rumonge	8.0	Ministry of wHydraulics, Energy and Mines	Preliminary study

Source: Ciza[6]

RENEWABLE ENERGY POLICY

The Government of Burundi aims to promote renewable energy as part of its efforts to protect the country's natural resources. This includes a range of planned hydropower, solar power, peat-fired and waste-to-power projects as well as exploration of the wind power and geothermal power potential in the country.[20] To support these efforts, the Government has prepared renewable energy legislation, which at the moment of writing of this chapter was under consideration. There are no feed-in tariffs in place.

As the majority of population uses wood as a source of energy for cooking, the Government of Burundi has planned a programme of planting trees across the country and calls the population to use other less polluting sources of energy, for example, ecological briquettes from biodegradable waste.

The following laws aiming to further liberalize the electricity sector have been implemented:

- Law No. 1/23 of 24 September 2008 defined tax benefits for investors;
- Law No. 1/177 of 19 October 2009 established the Investment Promotion Agency;
- Law No. 100/318 of 22 December 2011 established the ABER to develop and implement rural electrification projects and programmes;
- Law No. I/13 of 23 April 2015 aims to reorganize and liberalize the electricity sector;
- Electricity (Generation Services for Export and Electricity Importation) Regulations, 2016;
- Electricity Licensing (Generation Services for Own Use and Trade) Regulations, 2016;
- Electricity (Transmission, Distribution and Electricity Trade) Regulations, 2016.[16]

Licensing of SHP projects is overseen by the Regulatory Authority of Water and Energy Sectors (AREEN) and is a rather easy process. Each project is required to undertake an Environmental and Social Impact Assessment (ESIA).

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The Government of Burundi is the main source of financing for SHP projects in the country, including through PPPs and loans.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

So far, only minor effects of the climate crisis on the hydropower sector have been recorded in the country. Electricity generation drops in the summer period, which should be taken into account in future SHP developments. As adaptation measures for the hydropower sector, the Government uses generation from thermal power and plants trees around hydropower plants.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key barriers preventing SHP development in Burundi include:

- Lack of funds;
- Lack of local skills and expertise;
- Limited hydrological data.

At the same time a range of favourable conditions for SHP development exist:

- A very low electricity access rate and need for electricity sector development so that the country can develop economically, socially and financially;
- Significant improvements in the business environment in the country have been made;
- Policy focus on hydropower development;
- A range of suitable SHP sites have been identified.

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Ethiopia

Zelalem Girma, Arba Minch University; and Davy Rutajoga, International Center on Small Hydro Power (ICSHP)

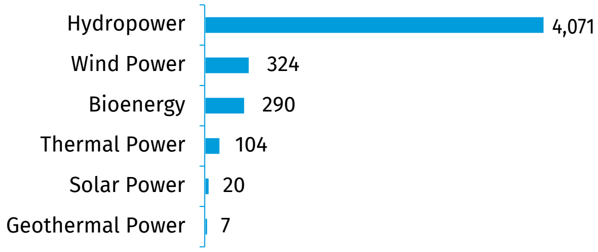
KEY FACTS

Population	114,963,583 (2020)[1]
Area	1,129,300 km^2[2]
Topography	Ethiopia has one of the most rugged topographies in Africa that can be categorized into five zones: the Eastern Highlands, the Western Highlands, the Eastern Lowlands, the Western Lowlands and the Rift Valley. The highest point in the country is the Ras Dejen (or Ras Dashen) mountain, peaking at 4,533 metres.[3]
Climate	Ethiopia is located in the tropical latitudes and thus experiences climatic conditions typical of tropical regions in its lowlands. The country's highlands, however, enjoy a temperate climate due to their elevation offsetting the desert-like conditions of the lowlands. This variety in topography translates into mean temperatures ranging from -15 °C in the highlands to over 25 °C in the lowlands.[4]
Climate Change	Ethiopia has been experiencing increasing temperatures and variabilities in rainfall patterns due to climate change. The average temperatures have been increasing, especially in the July-September period, by an average of approximately 1 °C since 1960, with an average increase rate of 0.25 °C per decade. The average number of hot nights and hot days has increased, while cold days have also been decreasing exponentially. The higher rates of warming have been observed to affect the central regions and highland areas more, with increased evapotranspiration and reduced soil moisture. There has also been observed a decrease in precipitation and an increase in volatility. The south-central region, for example, has seen a 20 per cent decrease in rainfall since 1960. This has all led to increased droughts and unpredictable rainfall patterns.[4]
Rain Pattern	Ethiopia experiences considerable variability in rainfall. The equatorial forests in the south and south-west receive high rainfall. Conversely, while the Afroalpine zone on the Bale and Simien Mountains as well as the eastern, north-eastern and south-eastern lowlands experience desert-like conditions. Ethiopia has three rainfall seasons: the rainiest season, or Kiremt, accounting for most of the rainfall between June and September; the Belg, which is a secondary wet season from February to May in the central and northern regions; and the Bega in the southern regions, which occurs from October to December. The mean annual rainfall is approximately 2,000 mm in the south-western highlands and approximately 300 mm in the south-eastern and north-eastern lowlands.[4]
Hydrology	Ethiopia has 9 major rivers and 12 big lakes, including Lake Tana, which is the source of the Blue Nile. There are three major drainage systems in Ethiopia: the Western drainage, which includes the Blue Nile (or the Abay River), the Baro Rivers and the Tekeze and flows towards the White Nile in South Sudan and Sudan; the Rift Valley internal drainage system, including the Awash River, Omo River and the Lakes Region; and the Shebele and Genale Rivers drainage system which flows southwards towards Somalia and the Indian Ocean.[3]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in Ethiopia are hydropower, wind power, bioenergy and solar power, respectively accounting for 93.9 per cent, 5.8 per cent, 0.2 per cent and 0.1 per cent of total production, which amounted to 14,553 GWh in 2019. All electricity production in the country was from renewable sources, with hydropower alone amounting to 13,655 GWh in 2019 (Figure 1).[5]

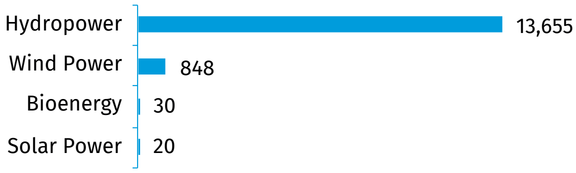
Figure 1. **Annual Electricity Generation by Source in Ethiopia in 2019 (GWh)**



Source: IRENA[5]

In 2020, the total installed electricity capacity in Ethiopia was 4,817 MW of which hydropower, wind power, bioenergy, solar power and geothermal power accounted for almost 85 per cent, less than 7 per cent, 6 per cent, 0.4 per cent and 0.3 per cent, respectively. Non-renewable thermal power capacity amounted to 104 MW (or 2.1 per cent) in 2020 (Figure 2).

Figure 2. **Installed Electricity Capacity by Source in Ethiopia in 2020 (MW)**



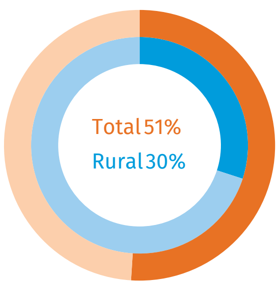
Source: IRENA[5]

Electricity in Ethiopia is regulated by the Ethiopia Electric Authority (EEA), while the Ethiopian Electric Utility (EEU) and the Ethiopian Electric Power (EEP) are responsible for generation, transmission and delivery. The latter was formed by Council of Ministers Regulation No. 302/2013.[6]

The EEA regulates tariffs for on-grid and off-grid electricity, with tariffs in Ethiopia being some of the lowest in Africa due to government incentives and a fixed cost of electricity. This tariff underwent an amendment in 2018, after which costs were ranging from 0.005 USD/kWh to 0.04 USD/kWh for residential consumers, and for industrial consumers from 0.03 USD/kWh to 0.02 USD/kWh.[7]

Electricity and the energy sector in general are a focal point of the Ten-Year Perspective Development Plan (2021–2030) of Ethiopia, also known as Vision 2030. Under Vision 2030, Ethiopia is projected to become a lower-middle income country and reach a 100 per cent electrification rate by 2025. The National Electrification Programme 2.0 (NEP 2.0) is the national strategy outlining the plan to achieve universal access to electricity through on- and off-grid solutions. Adopted in 2019, it is tied into Vision 2030 and highlights large-scale projects to double electricity production such as the Grand Ethiopian Renaissance Dam (GERD) and the 2,160 MW Koysha hydropower plant. The former, a large-scale hydropower project, is expected to be completed by 2023 but has already begun producing electricity and is expected to reach a production capacity of 6,450 MW, making it the largest hydropower plant in Africa.[8,9,10]

Figure 3. **Electrification Rate in Ethiopia in 2020 (%)**



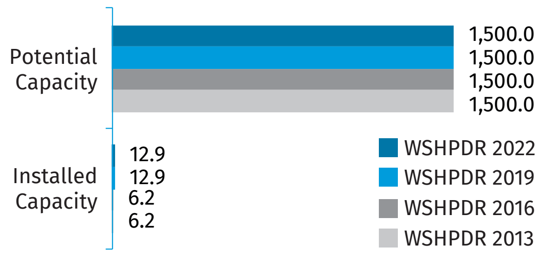
Source: World Bank[10]

The country's electrification rate was 51 per cent in 2020, with 30 per cent of the country's rural population having access to electricity (Figure 3). Electrification rates are expected to increase dramatically once the GERD is operating at full capacity.[11,12]

ALL HYDROPOWER SECTOR OVERVIEW

In Ethiopia, small hydropower (SHP) refers to plants with an installed capacity of up to 10 MW. The installed SHP capacity in 2018 was 12.89 MW and the SHP potential is estimated to be at least 1,500 MW, with most potential sites located in western and south-western Ethiopia.[13,17] The potential and installed capacity have not changed since the publication of the *World Small Hydropower Development Report (WSHPDR) 2019* as no new data have been made available (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Ethiopia (MW)**



Source: *WSHPDR 2013*,[14] *WSHPDR 2016*,[15] *WSHPDR 2019*,[16] MoST[17]

There is currently no reliable information on the number of SHP plants in operation in Ethiopia. In 2017, there were 28 operational SHP plants (Table 1).

Table 1. **List of Existing Small Hydropower Plants in Ethiopia**

Name	*River*	*Installed capacity (kW)*	*Potential upgrade up to (kW)*
Sor	Sor	5,000.0	–
Aba Samual	Aba Samuale	4,500.0	–
Dembi	Gilo	800.0	–
Jibo	Jibo	420.0	–
Yadot	Yadot	350.0	–
Ropi	Bilate	300.0	–
Gelenmite	Gelenmite	195.0	–
Chemoga	Chemoga	195.0	–
Welega	Welega	162.0	–
Hulka	Hulka	150.0	–
Yaye	Yaye	150.0	170.0
Sotosomere	Sotosomere	147.0	–
N/A	–	130.0	–
Deneba	Deneba	123.0	–

Name	*River*	*Installed capacity (kW)*	*Potential upgrade up to (kW)*
Hagara Sodicha	Lalta	43.5	55.0
Rago Senbete	–	30.0	–
Rasa Dango	–	30.0	–
Gobecho II	Gangea	28.0	34.0
Enkule	–	27.0	–
Shebe leku	–	18.0	–
Welega	–	15.0	–
Murago	–	15.0	–
Leku	Boru	13.0	20.0
Kersa	–	11.8	–
Ererte	Ererte	10.0	33.0
Keramo	–	10.0	–
Gera dusta	–	7.5	–
Gobecho I	Gangea	7.0	–
Total		**12,887.8**	

Source: MoST[17]

Note: Data as of 2017.

RENEWABLE ENERGY POLICY

As part of the NEP, a climate-resilient green economy approach is essential to achieving Vision 2030, and renewable energy is stated as one of the four pillars of this green economy. To achieve the Vision 2030 target of universal electricity coverage fixed by the Government of Ethiopia, a focus is made on the expansion of renewable energy in both the on- and off-grid mode.[9]

One of the policies addressed in the NEP is the National Biogas Programme (NBP) launched in 2009 with the aim of providing biogas digesters to Ethiopian households. In the first phase of the project, over 14,000 rural households were serviced and 360,000 low-income households are targeted for the current phase II. Further efforts to improve clean energy access in low-income households in the country were manifested in the National Improved Cookstove Programme (NICP), a programme launched in 2010 with the aim of providing cleaner cooking technologies to divest from traditional biomass-based fuels (firewood, charcoal). Within the first five years of implementation of the programme, over 9 million improved cookstoves had been distributed in Ethiopia. Under the Rural Electrification Fund launched in 2003, more than 45,000 solar home systems have been provided to previously unelectrified communities in Ethiopia and over 200 technicians were trained in the operation and maintenance of solar home systems.[9]

In response to the growing demand for renewable energy via off-grid systems, the Government of Ethiopia partnered with the International Development Association (IDA) to launch the Market Development Credit Line (MDCL) as part of the Electricity Network Reinforcement and Expansion Project (ENREP). Through this credit line, imports of technologies and equipment for renewable energy projects are facilitated by the supply of retail loans to Ethiopian private sector enterprises and small and medium-sized enterprises for up to two years, at 12 per cent interest and with guaranteed access to forex. The credit line also enables wholesale loans to Ethiopian micro-financial institutions in the local currency for up to six years at 6 per cent interest. The Government of Ethiopia is also considering alternative financial institutions to allow consumers in remote areas to be able to pay for their solar tariffs as part of the NEP.[9]

The Government has also implemented feed-in tariffs (FITs) for solar and wind projects, depending on the scale and location of the project, of between 0.05 USD/kWh and 0.06 USD/kWh.[14]

As a way to promote SHP development, the Government of Ethiopia introduced the Ethiopian Rural Energy Development and Promotion Centre (EREDPC). The EREDPC is overseen by the Ministry of Water, Irrigation and Energy and is mandated to promote and provide financing for SHP projects in rural Ethiopia through a rural electrification fund. Feed-in tariffs (FITs) are also being considered for hydropower to encourage private sector participation.[13]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP plants are regulated by the same legislation as larger hydropower projects. The main legislation and regulation documents in Ethiopia concerning hydropower projects are:

- Energy Proclamation No. 810/2013 (as amended by Proclamation No. 1058/2018);
- Energy Regulation No. 447/2019 (Energy Regulation), which supplements the Energy Proclamation. It regulates the consent and permit procedures for generation, transmission and distribution licenses, and provides guiding principles on tariffs;
- Investment Proclamation No. 1180/2020. This is the key piece of legislation that regulates investments in any sector, including energy;
- The Federal Water Resources Management Policy (1999).

BARRIERS AND ENABLERS TO SMALL HYDROPOWER DEVELOPMENT

The development of new SHP projects is hampered mainly by:

- The lack of available relevant information on the state and future of SHP in the country, which can discourage prospective investors;
- Although studies of hydropower potential are regularly conducted in the country, they often target larger-scale hydropower;

- Increasingly volatile political situation and conflicts affect SHP development as entire regions of the country are often out of access or too dangerous to be visited for potential site analysis. Many water resources are also found in these out-of-reach zones of conflict;
- The focus on large-scale hydropower projects to respond to the growing demand for electricity, such as the GERD project, is likely to eclipse the potential of SHP in solving those issues, particularly in remote and rural areas.
- Lack of expertise in manufacturing, installation and maintenance of equipment or parts for SHP plants;
- Expansion of irrigation projects in small hydrostreams may prevent hydropower development downstream.

Enablers for SHP development in Ethiopia include:

- Government support for renewable energy in general: this is an encouraging sign as future policies are likely to keep reflecting this engagement;
- Institutional support for hydropower development through encouraging policies that target small-scale renewable energy development, particularly in rural Ethiopia;
- Considerable water resources and SHP potential in Ethiopia;
- Increasing foreign investment and private sector involvement in small-scale off-grid reflects an increasing interest in renewable energy solutions to the electrification issues of the country;
- Establishment of the EREDPC with a mandate to promote renewable energy technologies for rural electrification. Under the EREDPC, soft loans with low interest rates are available to private power producers;
- The mini-grid directive launched in 2020 simplifies the process of obtaining licences for electricity generation, distribution and sale as well as tariff setting.

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Kenya

Sarah Acholla Kwach, Kenya Industrial Research and Development Institute (KIRDI)

KEY FACTS

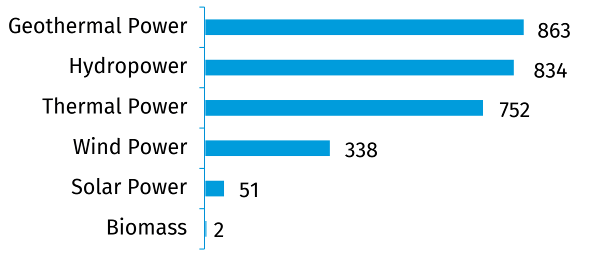
Population	53,771,300 (2020)[1]
Area	580,370 km[2] [2]
Topography	Kenya is located across the equator and is characterized by a diverse topography varying across its 47 counties.[3] Its Indian Ocean coastline contains swamps of the East African mangroves. Inland are broad plains and numerous hills. Central and western Kenya is characterized by the Rift Valley, home to the country's highest mountain and the second highest mountain in Africa, Mount Kenya, with an altitude of 5,199 metres above sea level. The landscape of Kenya includes deserts, such as the Chalbi, as well as glaciated mountain ranges.[2]
Climate	The climate of Kenya ranges from tropical in the southern, western and central regions to arid and semi-arid in the north and north-east.[4] Meanwhile, the country's central highlands have an equatorial climate.[5] Temperatures average 27 °C in the coastal areas, 19 °C in the capital, Nairobi, and 13 °C in the mountains.[6]
Climate Change	Climate change in Kenya has been well-documented, with both minimum and maximum daily temperatures on the rise since the early 1960s. Between 1960 and 2006, the minimum temperature has increased by 0.7-2.0 °C and the maximum by 0.2-1.3 °C.[7] Regionally, western parts of the country have seen the most significant temperature rise, with surface temperatures around Nairobi having risen by more than 2.5 °C since the 1960s. On the contrary, coastal areas have experienced more moderate warming trends. Projections of climate change for countries in the Eastern Africa region, including Kenya, forecast an increase in mean annual temperatures of 2.2 °C by 2065 and 4.0 °C by 2100 under a high-emissions scenario.[8]
Rain Pattern	The two rainy periods in Kenya are set apart by dry periods and referred to as the "long rains", from March to May, and the "short rains", from October to December. These have extensive implications for the country's agricultural system, with different crops being grown during each rainy period. The average annual rainfall is 630 mm, with a variation from less than 200 mm in northern Kenya to over 1,800 mm on the slopes of Mount Kenya.[2,9]
Hydrology	The drainage system of Kenya consists of five major basins: Lake Victoria, Rift Valley, Athi and the coastal area, Tana and Ewaso-Nyiro/North-Eastern. The two largest perennial rivers are the Tana (724 km) and the Athi-Galana-Sabaki (390 km). Both empty into the Indian Ocean.[10]

ELECTRICITY SECTOR OVERVIEW

The electricity sector of Kenya is characterized by a diversified energy mix and a high degree of reliance on renewable energy sources (RES). Petroleum products still form a major component of the national energy consumption, including for electricity generation, and demand for them continues to increase by approximately 10 per cent annually. However, Kenya is also endowed with an abundant RES potential, varying in type across geographic areas. The solar power potential is high across the country, while potential for biomass and hydropower is plentiful in the wet, forested central and southern regions. The wind power potential is highest in the north-west and parts of the Great Rift Valley, which also contains much of the country's geothermal energy resources.[11,12,13,14]

The installed generation capacity of Kenya has been increasing in recent years, and rose from approximately 2,819 MW in 2019 to 2,840 MW in 2020; however, the effective and contracted capacity in 2020 reached only 2,708 MW, in part due to the impact of the COVID-19 pandemic on the country's electricity sector.[14,15,16] Geothermal power was the single largest contributor of installed capacity in 2020 at 863 MW (30 per cent). Meanwhile, hydropower contributed 834 MW (29 per cent), thermal power 752 MW (26 per cent), wind power 338 MW (12 per cent), solar power 51 MW (2 per cent), and biomass 2 MW (less than 1 per cent) (Figure 1).[14] The geothermal power capacity expanded substantially in 2019 with the addition of the 165-MW Olkaria V plant, cementing the position of Kenya as one of the world leaders in geothermal power.[16,17] Given the additional importance of hydropower in the country's energy mix, the geothermal power capacity of Kenya is crucial in ensuring the security of electricity supply in periods of drought, with traditional thermal power deployed in a supplementary capacity. By the end of 2021, the installed capacity of traditional thermal power is expected to decrease to 622 MW, reflecting the country's ongoing transition to RES.[14]

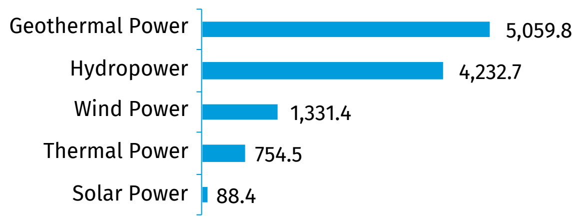
Figure 1. **Installed Electricity Capacity by Source in Kenya in 2020 (MW)**



Source: Government of Kenya[14]

In 2020, annual electricity generation in Kenya equalled 11,466.9 GWh, increasing slightly from 11,408.6 GWh in 2019. Of this total, 93 per cent of electricity was generated from renewable sources; geothermal power provided 5,059.8 GWh (44 per cent), hydropower 4,232.7 GWh (37 per cent), wind power provided 1,331.4 GWh (12 per cent), and solar power 88.4 GWh (1 per cent). Generation of electricity by thermal power, the only non-renewable source, accounted for 754.5 GWh (7 per cent) (Figure 2).[16]

Figure 2. **Annual Electricity Generation by Source in Kenya in 2020 (GWh)**



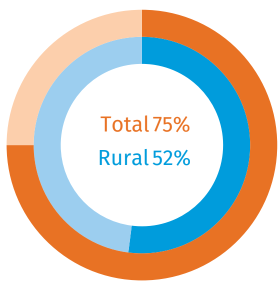
Source: KNBS[16]

In 2019, wind power generation experienced a more than four-fold increase relative to the previous year and reached 1,562.7 GWh, due to the full operationalization of the 310 MW Lake Turkana wind power plant, while solar power generation increased by nearly seven times relative to 2018 due to the commissioning of the Garissa power plant. However, in 2020 generation from both energy sources decreased slightly. In 2019, imports of electricity reached 212.0 GWh, but decreased to 136.7 GWh in 2020.[16,18]

In 2020, the total electricity supply decreased to 11,603.6 GWh from 11,620.7 GWh in 2019, with domestic demand falling to 8,796.4 GWh from 8,854.0 GWh over the same period. Transmission and distribution losses amounted to 2,790.7 GWh in 2020, accounting for 24 per cent of the total electricity supply.[16] Prior to 2020, Kenya had been experiencing an upward trend in electricity demand. The rise in demand has been associated with the increased number of consumers connected to the grid and the Government's efforts to attain universal access to electricity by 2022, as laid out in the Kenya National Electrification Strategy 2018–2022.[17] However, the economic slowdown induced by the COVID-19 pandemic led to a decrease in electricity demand of up to 8 per cent, with a system peak demand of 1,926 MW in February 2020 dropping to 1,465 MW in April 2020.[19] Further expansion of generating capacity to meet the rising demand is targeted at geothermal power, as part of a push to eliminate generation from fossil fuels.[20]

In 2018, access to electricity in Kenya stood at 75 per cent, with 52 per cent in rural areas (Figure 3).[21,22] Nationwide, almost 54 per cent were connected to the national grid and another 22 per cent were using off-grid solutions as their main source of electricity.[21] By 2020, overall access to electricity increased to 77 per cent, establishing Kenya as a regional leader in electricity access. The number of consumers connected to the national grid has grown rapidly in recent years, from 3,611,904 customers in 2015 to 7,576,145 in 2020, with an average annual increase of approximately 19 per cent. During the 2019/2020 reporting year alone, over 400,000 new customers were connected to the national grid. Rural connections reached 1,502,943 customers in 2020, accounting for approximately 20 per cent of all connections.[14,15] These results were achieved through a number of interventions by the Government of Kenya in collaboration with development partners, including the Last Mile Connectivity Programme (LMCP), electrification of all public primary schools, the Global Partnership on Output-Based Aid (GPOBA), the Rural Electrification Programme (REP), the Kenya Off-Grid Solar Access Project (KOSAP), the Slum Electrification Project (SEP), the Lifeline Tariff and the Energy and Cash Plus Initiative.[17]

Figure 3. **Electrification Rate in Kenya in 2018 (%)**



Source: The World Bank[21,22]

Despite the accelerating growth of the electrification rate, nearly 25 percent of the population still lack access to electricity.[15] Obstacles to full electrification include high connection charges, high costs of supplying electricity to rural areas, lack of incentives for private investment, inappropriate technical standards, general lack of capacity, administrative barriers and demands for excessive compensation for the issuing of development licences.

The key institutions in the energy sector of Kenya include the following:

- Ministry of Energy and Petroleum (MOEP), the lead Government institution in charge of making and articulating energy policies as well as granting and revoking generation and distribution licences upon the recommendation of the Energy and Petroleum Regulatory Authority (EPRA);

- Energy Tribunal, an independent legal entity that arbitrates disputes between parties in the energy sector;
- Energy and Petroleum Regulatory Authority (EPRA), previously the Energy Regulatory Commission (ERC), the independent regulator established under the Energy Act, 2019. EPRA's mandate includes licensing, technical and economic regulation, enforcement and compliance and handling of complaints and dispute regulation;
- Kenya Power and Lighting Company (KPLC, also Kenya Power), a public company that transmits, distributes and retails electricity to customers in the country;
- Kenya Electricity Generating Company (KenGen), a state-owned company that owns approximately 72 per cent of the country's installed capacity and is responsible for developing new public sector generation facilities to meet increased demand;
- Rural Electrification and Renewable Energy Corporation (REREC), mandated by the Energy Act, 2019 to be the lead agency for the development of renewable energy resources other than geothermal power and large hydropower, in addition to its previous mandate of rural electrification;
- Geothermal Development Company (GDC), a wholly state-owned Special Purpose Vehicle that undertakes surface exploration of geothermal fields, explorations, appraisals, drilling, steam production and entering into steam sales agreements with investors in geothermal electricity generation;
- Electricity Transmission Company (KETRACO), a wholly state-owned company responsible for the development of the national transmission grid network and for the facilitation of regional power trade through the transmission network;
- Independent Power Producers (IPPs), involved in generation either on a large scale or in renewable energy projects under the feed-in-tariff policy;
- Nuclear Power and Energy Agency (NPEA), formerly Kenya Nuclear Electricity Board (KNEB), a state-owned corporation established under the Energy Act, 2019 and charged with the responsibility of promoting and implementing the country's Nuclear Power Programme as well as carrying out research and development for the nuclear energy sector. To date, no nuclear plants have been built in Kenya;
- Kenya Renewable Energy Association (KEREA), an independent non-profit association dedicated to facilitating the growth and development of renewable energy enterprises in the country;
- Private distribution companies are proposed under the Energy Act, 2019 with the intention of enhancing competition in the distribution sector and thereby improving efficiency. It is envisaged that future power distribution will involve the purchase of bulk power from power generating companies. With KETRACO facilitating the transmission, generating companies will be able to sell power directly to consumers;
- County governments, which, under the Energy Act, 2019, are required to prepare county energy plans for the Cabinet Secretary. Some counties provide supplementary funding for rural electrification;
- Independent entities that act as arbiters in disputes between parties in the energy sector;
- Mini-grids, supplying electricity to a localized group of customers not covered by the national power grid as approved by EPRA.

Over the last years, the Government of Kenya has accelerated its efforts in upgrading the existing transmission and distribution networks and building new ones for effective power evacuation. The national grid network is composed of 400 kV, 220 kV and 132 kV transmission systems, while the distribution network includes 66 kV, 33 kV and 415/240 V systems.[15] The total length of the transmission and distribution network increased to 243,207 kilometres for all voltage levels in 2019/2020, compared to 59,322 kilometres in 2014/2015, with the length of the transmission network alone at 7,174 kilometres.[14] The expansion of the network has been spearheaded by KETRACO. As of the moment of writing of this chapter, KETRACO was in the process of constructing approximately 4,500 kilometres of new lines as well as connecting the power systems of Kenya and Ethiopia through the construction of a 1,045-kilometre 500 kV high voltage direct current (HVDC) transmission line and 2,000 MW HVDC converter substations at both ends of the line.[23,24] The Kenya-Ethiopia electricity interconnection will represent the longest transmission line in Eastern and Middle Africa, as well as the first direct current line in Kenya having 500 kV high-voltage direct current.[25] The entire national interconnected electricity distribution network is operated by KPLC.

EPRA sets, reviews and adjusts electricity tariffs and tariff structures in line with key policy objectives.[21.] The set tariffs must be approved by the regulator before enforcement. Retail electricity tariffs vary according to the customer category (Table 1).

Table 1. **Electricity Tariffs in Kenya for 2018/2019**

Consumer category	*Consumption limit (kWh/month)*	*Electricity charge (KSH/kWh (USD/kWh))*	*Demand charge (KSH/kVA (USD/kVA))*
Domestic-Lifeline (240 V)	< 100	10.0 (0.09)	-
Domestic-Ordinary (240 V)	> 100	15.8 (0.14)	-
Small Commercial 1 (240 V)	Up to 100	10.0 (0.09)	-
Small Commercial 2 (240 V)	101–15,000	15.6 (0.14)	-
Commercial/Industrial (415 V)	> 15,000	12.0 (0.11)	800 (7.28)
Commercial/Industrial (11 kV)	No limit	10.9 (0.10)	520 (4.73)
Commercial/Industrial (33 kV)	No limit	10.5 (0.10)	270 (2.46)
Commercial/Industrial (66 kV)	No limit	10.3 (0.09)	220 (2.00)
Commercial/Industrial (132 kV)	No limit	10.1 (0.09)	220 (2.00)
Street lighting	No limit	7.5 (0.07)	-

Source: EPRA,[15] KPLC[26]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Kenya generally includes hydropower plants with an installed capacity of up to 3 MW (Table 2), but some government sources define SHP as plants of up to 10 MW.[27,28,29] For the purposes of this chapter, the up to 10 MW definition will be used.

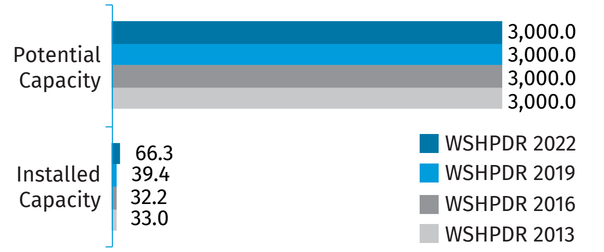
Table 2. **Definitions of Small Hydropower in Kenya**

Category	*Capacity range (kW)*
Pico	< 5
Micro	5–100
Mini	100–1,000
Small	1,000–3,000

Source: MOEP,[27] Ngure[28]

As of 2019, total installed capacity of SHP up to 10 MW in Kenya stood at 66.26 MW, including 26.99 MW operated by KenGen and 39.27 MW by private companies and rural communities.[14,18,30,31,32] Undeveloped potential capacity for SHP up to 10 MW is estimated at 3,000 MW.[29,33] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity increased by approximately 68 per cent due to up-to-date information on recently commissioned plants becoming available. Potential capacity has remained the same as no new country-wide studies of SHP potential have been conducted since 2004 (Figure 4).[34]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Kenya (MW)**



Source: Government of Kenya,[14] KPLC,[18] MOEP,[29] The World Bank,[30] Vogeler et al.,[31] EPRA,[32] *WSHPDR 2019*,[34] *WSHPDR 2013*,[35] *WSHPDR 2016*[36]

SHP development in Kenya accelerated following the introduction of the feed-in-tariff (FIT) policy in 2008, with the majority of new SHP plants constructed by the Kenya Tea Development Authority (KTDA). The plants are expected to significantly reduce energy costs of operation for KTDA tea factories as well as generate surplus electricity, which will be sold to the national grid.[31] A list of the 20 most recently commissioned SHP plants is displayed in Table 3.

Table 3. **List of Selected Operational Small Hydropower Plants in Kenya**

Name	*Location (River)*	*Capacity (MW)*	*Operator*	*Launch Year*
Iraru	Iraru	1.50	KTDA	2017
Nyakwana	Kisii	2.00	KTDA	2017
Teremi Falls	Kyuwa	5.00	GenPro Power Systems Ltd.	2017
Gura	Gura	5.80	KTDA	2016
Chania	Chania	1.00	KTDA	2016
North Mathioya/Metumi	Mathioya	5.60	Metumi Power Co Ltd	2016
Lower Nyamindi	Nyamindi	1.80	KTDA	2016
South Mara	South Mara	2.00	KTDA	2016
Nyabunde	Gucha	0.50	KTDA	2016
Gikira	Gikira	0.51	Kengen	2014
Tindinyo Falls	Yala	1.50	Tindinyo Falls Resort	2014
Imenti	Imenti	0.90	KTDA	2009
Kleen Energy	Embu	6.00	N/A	2008
Community MHPs	N/A	0.02	Community	2002
Thima	Mukenge-ria	0.01	Community	2001
Kathamba	Kathamba	0.00	Community	2001
Tungu-Kabiru	Tungu	0.01	Community	2000
James Finlay 5	Kericho	1.10	Tea Company (James Finlay)	1999
Diguna	N/A	0.40	Missionary	1997
James Finlay 4	Kericho	0.3	Tea Company (James Finlay)	1984

Source: Government of Kenya,[14] KPLC,[18] MOEP,[29] The World Bank,[30] Vogeler et al.,[31] EPRA,[32] *WSHPDR 2019*[34]

Various studies conducted in Kenya over the past 10 years have identified many prospective sites for SHP development.[14,37,38] More than 260 individual potential hydropower sites have been identified, with the largest number found in the Tana River drainage basin, an area with a high population density and energy demand.[39] Both existing and prospective SHP plants in Kenya are often designed as stand-alone electricity supply facilities for agro-industrial establishments, in particular tea factories. A survey of 72 tea factories in Kenya indicated that 80 per cent are located 3–15 kilometres away from a potential hydropower site, although no detailed assessments of potential have been carried out. The KTDA can be expected to continue playing a major role in the development of SHP in the country, having committed itself to an array of SHP projects to be commissioned throughout the 2020s.[14] Table 4 displays several SHP projects currently under construction.

Table 4. **List of Selected Ongoing and Planned Small Hydropower Projects**

Name	*Location*	*Capacity (MW)*	*Developer*	*Planned Launch Year*
Kianthumbi	Meru	0.51	Hydro Project Service Peters Ltd.	2021
Gatiki Small Hydro Plant		9.60	Power Technologies	2022
Nithi Hydro	Tharaka Nithi	5.60	Frontier	2025
Kipsonoi 1	Bomet	0.60	KTDA (Settet Power Co.)	2025
Buchangu		4.50	Global Sustainable Ltd.- Buchangu	2026

Source: Government of Kenya,[14] The World Bank[30]

RENEWABLE ENERGY POLICY

The Energy Act, 2019 introduced various reforms to the energy sector of Kenya, aligning the sector with the Constitution of 2010 regarding the functions of the national and county governments.[40] Notably, through the introduction of the RES FIT system, the Act developed on the FIT policy introduced by MOEP in 2008 and reviewed in 2010, 2012 and 2021. The 2021 FIT Policy is a revision of the 2012 FIT Policy, with substantial changes introduced to the process of RES project development in Kenya to better align the Policy with the Energy Act, 2019 and other recent developments in the Kenyan energy sector. The FIT policy has been supplemented by the Renewable Energy Auction Policy (REAP) of 2021; FITs now apply to RES power plants not exceeding 20 MW and relying on biomass, biogas or small hydropower, while energy auctions have replaced FITs for solar and wind power and for all RES plants above 20 MW.[42] The current FITs for RES are listed in Table 5.

Table 5. **Feed-in Tariffs for Renewable Energy Projects in Kenya as of 2021**

Plant type	*Installed capacity (MW)*	*Standard FIT (USD/kWh)*	*Scalable portion of the tariff*
Hydropower	0.5	0.090	8%
	10	0.082	
Biomass	0.5 - 10	0.095	15%
Biogas	0.2 - 10	0.095	15%

Source: Ministry of Energy[43]

Note: For values between 0.5 MW and 10 MW, interpolation shall be applied to determine the tariff for hydropower.

The Energy Act, 2019 was adopted to consolidate the laws relating to energy and the promotion of RES, replacing the previously adopted Energy Act of 2006, Kenya Nuclear Electricity Board Order of 2013 and the Geothermal Resources Act of 1982. The new Act gave greater recognition to non-traditional energy sources, including RES and nuclear energy.[44] Additional legislation important for the RES sector includes:

- Sessional Paper No.4 of 2004, which cemented the process of liberalizing the energy sector started in the 1990s;
- the Electricity Licensing Regulations of 2012, which detail the permit and licensing requirements that are applied to any individual or entities undertaking or planning to engage in electricity generation, transmission, distribution or retail supply business;
- the VAT Act (2013) and the Amended VAT Act (2014), which exempt investors in RES from value-added tax and import duties on temporary and permanent materials and equipment required for RES projects;
- the Public-Private Partnerships Act of 2013, which provides for the participation of the private sector in the financing, construction, development, operation and maintenance of public infrastructure and development projects; and
- the Public Procurement and Asset Disposal Regulations of 2020, which seek to harmonize and operationalize public procurement procedures.[29,45]
- Renewable Energy Auction Policy (REAP) 2021, the primary objective of which is to procure renewable energy capacity in line with the LCPDP and the Integrated National Energy Plan (INEP) at competitive prices through the establishment of energy auctions.[42]

In additional to regulatory legislation, promotion of RES development in Kenya is realized through the following strategies and plans:

- The long-term development strategy of Kenya, Vision 2030, targets energy access as a key enabler for achieving its development targets, including projected increases in population, which are in turn expected to lead to a rise in electricity demand. According to the Least Cost Power Development Plan (2011–2031), the demand for electricity in Kenya is projected to grow to 15,065 MW by 2030;

- Sustainable Energy for All (SE4ALL) Action Agenda, which outlines how the country will achieve universal access to modern energy services, increase the rate of energy efficiency and increase the share of RES in the energy mix to 80 percent by 2030;
- The Kenya Electricity Sector Investment Prospectus 2018–2022, which outlines investment and financing opportunities in geothermal power development, power generation, electricity transmission and distribution, off-grid electrification and energy efficiency;
- The Investment Plan for Scaling-Up Renewable Energy (SREP), currently under implementation, supports the development of hybrid mini-grid systems based on RES for electrification in rural areas where grid extension is unlikely to be viable in the short and medium term.
- The Least Cost Power Development Plan (LCPDP) 2021 – 2030, which highlights the Government's intention to prioritize the development of geothermal, wind and solar energy plants as well as solar-fed mini-grids for rural electrification.[14]

The available incentives for RES development in Kenya include:
- Exemption from stamp duty for registration of companies;
- Exemption from stamp duty for instruments executed in transactions relating to loans from foreign sources for the purposes of investing in the energy sector;
- Investment deductions at the rate of 100 per cent for power generating plants and equipment, including the building housing the power generating plant and plants operating within Export Processing Zones; and at 150 per cent for plants located outside Nairobi, Mombasa and Kisumu;
- Insurance cover by the Multilateral Insurance Guarantee Agency (MIGA);
- Development of Public Private Partnerships by the Government in line with the Public Private Partnership Act No. 15 of 2013;
- Letters of support issued by the Government to both project companies and their financiers to enable project implementation;
- Kenya has no restrictions on converting or transferring investment funds;
- Foreign Investment Protection Act, Chapter 518, which guarantees capital repatriation and remittance of dividends and interest to foreign investors.

Licences and permits required for operating a power plant in Kenya include a generation licence and a distribution licence, both issued by MOEP; water rights (in the case of hydropower), obtained from the Ministry of Water Resources; and an Environmental Impact Assessment issued by the National Environmental Management Authority of the Ministry of the Environment. In case of sale of power to the grid, additional requirements include a power purchase agreement and adherence to generation and distribution standards.[46] Finally, approval of development permissions and building plans by the relevant county government and registration of the project site as a workplace with the Director of Occupational Safety and Health under the Occupational Safety and Health Act, 2007.

COST OF SMALL HYDROPOWER DEVELOPMENT

The cost of SHP construction in Kenya varies considerably based on location and the difficulty of preparing a site for construction, as well as other factors including the local economy and tax regime.[38] It is generally considered that the location and site preparation determine approximately 75 per cent of project costs, against only 25 per cent for the equipment.[47] The investment cost of an SHP plant in Kenya ranges anywhere from 1,000 to 20,000 USD/kW.[38] Maintenance costs of SHP plants in Kenya are relatively small in comparison to other technologies such as diesel generators. The initial investment cost as well as negative impacts on the environment can be greatly reduced by utilizing already existing impoundments and weirs.[38]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Financing models utilized by developers in Kenya involve a combination of several approaches including community finance, public funding, equity investment, grants and loans from local financing institutions. For instance, in 2015, KTDA signed a KSH 5.5 billion (USD 50 million) loan agreement with the International Finance Corporation (IFC), in partnership with the Global Agriculture and Food Security Program (GAFSP), the French Development Finance Institution (Proparco) and the Netherlands Development Finance Company (FMO) to fund the construction of seven SHP projects across tea growing regions.[48]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT.

The hydropower sector of Kenya as a whole is vulnerable to climate change, creating broad implications for the entire economy due to the relative weight of hydropower in the country's energy mix.[49] Reduced rainfall in recent years has already made hydropower production increasingly unreliable, forcing the Government of Kenya to introduce new policies and strategies that place a greater emphasis on promoting other RES.[50] Furthermore, climate change is putting additional pressure on traditional fuels including firewood and charcoal, access to which is becoming increasingly restricted as forest cover has receded.[51] SHP projects can expect to face resistance if they are perceived as further limiting access to these resources.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Some of the main obstacles to the development of RES, and SHP specifically, in Kenya include the following:

- Relatively long lead times for RES projects (from five to seven years);
- High upfront investment and capital costs, including the cost of ancillary infrastructure due to long distances to existing load centres;
- Political risks and conflicts relating to land use;
- Inadequate expertise and technical capacity in the RES sector as well as limited local capacity to produce RES materials and equipment;
- Lack of coordination between government agencies in policy implementation and promotion of RES projects, excessive licensing requirements as well as weak enforcement of standards and regulations;
- Vulnerability to climate change;
- Lack of awareness of the economic benefits of RES.

Additional barriers, specifically pertaining to the implementation of the FIT policy, include the following:

- Insufficient data and analytical tools to accurately formulate the tariff rates for different technologies;
- Lack of awareness of FITs among potential investors;
- No clear guidelines on power purchase agreement negotiations;
- Preference for certain RES technologies over others.

Enablers for SHP development include:

- High potential capacity of SHP, little of which has been realized so far;
- Incentives, including FIT and exemptions from certain taxes and duties on RES; and
- Favourable climate for private investors, which includes a robust public-private partnership framework.

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Madagascar

Joelinet Vanomaro, Technical Director of Rural Electrification Agency (ADER)

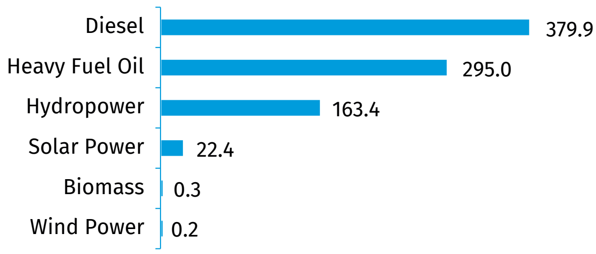
KEY FACTS

Population	26,923,353 (2021)[1]
Area	587,295 km^2[2]
Topography	Referring to its physical map, Madagascar has an asymmetry with respect to its main axis. The western part extends gently towards the Mozambique Channel, while the eastern part has a very steep slope leading towards the Indian Ocean. Topographically, the island can be divided into three main parts: the central highlands with an altitude ranging from 800 to 1,500 metres and a peak of 2,876 metres (Maromokotra), followed by the eastern slopes and finally the sedimentary zone of the north-west, west and south.[3]
Climate	Madagascar lies in the tropics and has two seasons and five main climatic regions comprising the East Coast, Uplands, West Coast, Southern and Sambirano regions. The cool, dry season begins in mid-April and ends in mid-October. The hot, rainy season begins in mid-October and ends in mid-April of the following year. The temperature is very varied in these areas but the absolute minimum of 1 °C is observed in the highlands (Antsirabe) in July, while the absolute maximum temperature was recorded in the extreme south at a value of 43.6 °C.[4,]
Climate Change	The trend of temperature increase has been significant in Madagascar since 1950. By 2055, the annual average temperature is projected to increase by 1.1 2.6 °C. Each region will have a variation in rainfall, but it is expected to be more intense in the western part. The number of more intense cyclonic disturbances has increased and the most affected areas have migrated towards the north-east of the island. As far as cyclones are concerned, the average annual number is not expected to change but the number of intense cyclones is expected to increase by 2100.[5,6]
Rain Pattern	Rainfall varies across the five climatic regions. Annual average rainfall exceeds 2,000 mm in the East Coast and in the Sambirano region. The Uplands, West Coast and Southern regions have an annual rainfall of 1,200, 950 and 600 mm, respectively. The annual minimum is 500 mm as observed in the South, which has a semi-arid climate. The maximum rainfall can be found in the East Coast, which has a hot and humid climate, at a value of 3,700 mm with 260 rainy days per year.[4]
Hydrology	There are more than 10 major rivers in Madagascar. Their tributaries constitute river networks scattered across different corners of the big island. The drainage pattern is a consequence of the asymmetric nature of the country's relief. As a result, the rivers in the west are longer, while those in the east are shorter and have a more accentuated course with numerous waterfalls, sometimes of considerable height. The periodic passage of tropical depressions, especially in the eastern and north-eastern parts of the country, makes the hydrological regimes extremely complex.[3]

ELECTRICITY SECTOR OVERVIEW

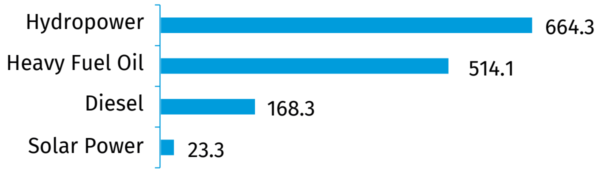
Madagascar uses several energy sources to generate electricity: hydropower, hybrid solar photovoltaic-diesel, heavy fuel oil and diesel. In 2020, 50.2 per cent of the produced electricity came from renewable sources, while 49.8 per cent came from fossil fuel sources. The total electricity generation in 2020 amounted to 1,370 GWh (Figure 1). Biomass and wind power plants are also used but in negligible proportions compared to the other sources. The total installed capacity of the country was 861.2 MW in 2020, with renewable sources accounting for approximately 22 per cent (Figure 2).[7]

Figure 1. **Annual Electricity Generation by Source in Madagascar in 2020 (GWh)**



Source: Ministry of Energy and Hydrocarbons[7]

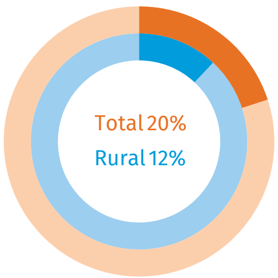
Figure 2. **Installed Electricity Capacity by Source in Madagascar in 2020 (MW)**



Source: Ministry of Energy and Hydrocarbons[7]

Madagascar does not import or export electricity due to a lack of geographical proximity to other countries. With regard to electricity access, the data collected by the Rural Electrification Development Agency (ADER) in January 2020 shows a national rate of almost 20 per cent, dividing the number of people with access to electricity infrastructure by the total population. Electrification rate is 12 per cent in rural areas and 67 per cent in urban areas.9

Figure 3. **Electrification Rates in Madagascar in 2020 (%)**



Source: ADER[9]

The electricity sector has been liberalized since 1999 following law No. 98-032 on the reform of the electricity sector. This liberalization is improved and confirmed by Law 2017-020 of 10 April 2018 on the Electricity Code of Madagascar.[8] Thus, the private sector is encouraged to finance all or part of the infrastructure through a contract signed with the Government for a fixed period of time.

The explanatory memorandum of the Electricity Code of Madagascar also specifies the attributions of the public sector.[8] The public sector is composed of the Ministry of Energy and Hydrocarbons, the Regulator and ADER. Since the adoption of the Electricity Code, ADER has been responsible for defining national electricity policy and coordinating the planning of all projects in the sector. Its remit is also the development of electrification in rural and peri-urban areas and the implementation of national policy in these areas.

Currently, Madagascar has three interconnected grids: RIA (Antananarivo), RIT (Toamasina) and RIF (Fianarantsoa), with the other major cities and rural villages supplied by off-grid power plants.[9] Two projects are being implemented for the interconnection of RIT with RIA first and RIA with RIF later, through the PRIRTEM I and PRIRTEM II projects supported by the African Development Bank and the European Union.[10]

Tariff regulation is the subject of an entire title of the Electricity Code of Madagascar.[8] It concerns sales of power and energy and their surpluses between the different actors in both interconnected and off-grid networks. The Regulator is empowered to approve the regulated tariffs. For national networks managed by national companies, four tariff zones are established according to the energy source that feeds them. In decentralized rural electrification, the tariff varies according to the business plan presented by the operator. In 2020, the average household electricity tariff was 0.120 USD/kWh and the average tariff for businesses was 0.118 USD/kWh.[11]

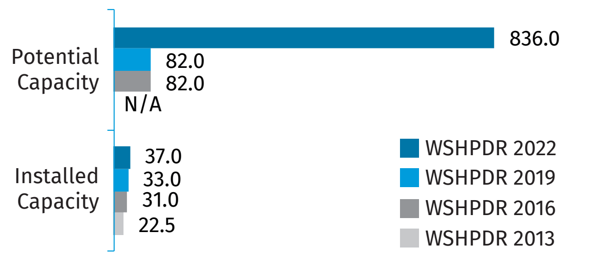
Several governmental decrees (notably Decree 2005-062 of 25 January 2005, Decree 2001-803 of 19 September 2001 and Decree 2003-194 of 4 March 2003) specify the role of the Regulator, which is responsible for the control of the electricity sector, including the determination and publication of regulated prices and fees, as well as the monitoring of their correct application.[12] The supervision of the respect of the quality-of-service standards, the control and respect of the competition principle, the mediation service, the follow-up and control of the execution of the concession and authorization contracts, the supervision of the elaboration of the Grid Code are also part of its attribution.[8]

SMALL HYDROPOWER SECTOR OVERVIEW

Madagascar does not have an official classification of hydropower plants. Thus, this chapter uses the definition of small hydropower (SHP) as plants with capacity up to 10 MW.

The installed capacity of SHP in Madagascar is 37 MW, of which 26.3 MW is available capacity. There are currently 36 installed SHP plants, of which 25 are operational. The other 11 with a total capacity of 0.5 MW require refurbishment.[16] Twenty-six of the plants, with a total capacity of 6.62 MW, are off-grid. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity increased by 12 per cent as a result of the commissioning of three new power plants (Figure 4, Table 1). The reason for the increase of the potential figures is access to more advanced and accurate data. According to the results of a study undertaken by ESMAP, which was completed in 2017, the unexploited theoretical potential of SHP up to 10 MW in Madagascar is 799 MW, making the total potential capacity 836 MW.[3] This study was performed by SHER consultancy using their internal software SiteFinder and based on an assumption of a 50 per cent annual average flow rate.

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Madagascar (MW)**



Source: ESMAP,[3] *WSHPDR 2013*,[13] *WSHPDR 2016*,[14] *WSHPDR 2019*,[15] ADER[16]

Table 1. **List of Selected Operational Small Hydropower Plants in Madagascar**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Behenjy	RIA	2.00	Hydro Mado	2021
Androkabe	Androkabe	1.50	BETC Nanala	2019
Ambatomanoina	Ambatomanoina	0.10	BETC Nanala	2019
Ankazomiriotra	Ankazomiriotra	0.12	Green Power	(2009) 2018*
Amberivery	Amberivery	0.04	Association FIMJA	2017
Amboasary Nord	Amboasary Nord	0.06	AIDER	2016
Sahambano	Sahambano	0.70	ERMA	2015
Ankilizato	Ankilizato	0.10	HIER	2015
Soavina	Soavina	0.06	HIER	2015
Fandriana	Fandriana	0.56	HIER	2014
Andriba	Andriba	0.09	SERMAD	2014
Sahasinaka	Sahasinaka	0.08	ECOGEMAT	2014
Tolongoina	Tolongoina	0.06	SM3E	2013
Tsiazompaniry	RIA	5.00	HFF	2010
Maroantsetra	Maroantsetra	2.58	TOZZI GREEN	2010
Ambaravaranala	Ambaravaranala	0.04	AIDER	2010
Andriantsemboka	Andriantsemboka	0.01	AIDER	2009
Andriantsiazo	Andriantsiazo	0.01	AIDER	2009
Antetezambato	Antetezambato	0.05	ADITSARA	2003
Namorona	RIF	5.60	JIRAMA	1980

Source: ADER[16]

Note: * The plant was constructed in 2009, but is undergoing refurbishment since 2018 following destruction after a cyclone in 2017.

In addition to the existing SHP capacity, three more projects were under development as of early 2021 (Table 2).

Table 2. **List of Ongoing Small Hydropower Projects in Madagascar**

Name	*Location*	*Capacity (MW)*	*Developer*	*Planned launch year*	*Stage of development*
Bealanana	Bealanana	0.40	HIER	2021	95%
Sahatona	Sahatona	1.60	HIER	2021	95%
Maheriara	Maheriara	0.70	BETC Nanala	2022	80%

Source: ADER[16]

Several aspects hamper SHP development in Madagascar. Thus, turbine manufacturing is not yet well-developed in the country and most turbines are still imported, which increases the cost of project implementation. The maximum power of locally manufactured turbines is 100 kW, but their efficiency is not entirely satisfactory. Additionally, rainfall reference stations do not cover the entire territory and geographical interpolations are often required, which introduces error. The hydrological monitoring of the rivers and streams, on which SHP plants are developed, is insufficient. In fact, it is often the case that daily monitoring is organized at the time of the elaboration of the feasibility studies and subsequently stops when the services of the consulting firms hired to carry them out are completed.

Exchange with countries already advanced in turbine manufacturing and related technology transfer is strongly recommended to further develop the sector in Madagascar. In connection with the implementation of the SHP development programme, hydrological monitoring with the installation of rain gauges should be carried out at the sites planned for development and should be continuous even if the plant is already in operation.

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

As of early 2021, the following SHP projects were at an advanced stage of study and ready for development. They have been identified in the Indicative Regional Development Plans. The selection of operators for their development is subject to a call for tender.

Table 3. **List of Small Hydropower Plants Available for Development in Madagascar in 2021**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/refurbishment)*
Belaoko Lokoho	Belaoko Lokoho	8.0	48.0	New
Andriamanjavona	Andriamanjavona	1.3	73.0	New
Angadanoro	Angadanoro	3.3	38.7	New
Mandalobe	Mandalobe	0.6	26.6	New
Ampasimbe	Ampasimbe	0.7	61.0	New

Source: ADER[16]

RENEWABLE ENERGY POLICY

Madagascar has ratified the Paris Agreement on climate change through Law 2016-019 and is currently developing a national strategy for each sector.[17] For the energy section, a consultation with all stakeholders was organized in February 2021. The Letter of Energy Policy 2015–2030 remains the official document containing quantified objectives in terms of renewable energy use.[18] The objective is to have an 85 per cent share of renewable energy sources in the energy mix by 2030, of which 75 per cent is to come from hydropower, 5 per cent from solar power and the remaining 5 per cent from wind power. To achieve this energy mix target, in 2015 the Government launched a call for tenders for the development of two hydropower plants: the Volobe project with a capacity of 120 MW and the Sahofika project of 205 MW.[19,20] As of early 2021, the future concessionaire had already been selected and the negotiations on the purchase contract and the concession contract were underway. In addition, the Government, which was elected in 2019, has set a target of doubling renewable energy capacity from 400 MW to 800 MW by 2023 and achieving a 50 per cent electricity access rate, including 40.8 per cent access in rural areas, where 80 per cent of the population lives. In rural areas this is to be achieved in part by the development of SHP with a total power of 35 MW until 2023, with the following phasing: 3 MW in 2021, 6 MW in 2022 and 26 MW in 2023.

According to Law 2017-020 of 10 April 2018 on the Electricity Code of Madagascar, tariffs should reflect costs. In the case of distribution to end customers, tariff setting must take into account the customers' ability to pay and the operator's financial equilibrium. This law also contains incentives for the use of renewable energy by providing for tax breaks. But the clauses on these measures are referred to in the finance law. In practice, these measures consist of customs duty exemptions and VAT exemptions. In the case of injection into the grid, priority is given to energy from renewable sources.

With regard to the price per kWh, the tariff applied on the national grid varies according to the energy source, with four tariff zones being distinguished. This difference can also be seen in the tariffs applied in isolated networks, where no standardization is carried out, but the fact remains that localities supplied by hydropower find their tariffs more affordable compared to localities served by other sources.

The development of a hydropower plant takes a long time and is not always in line with the promises made by candidates at election time. The elaboration and implementation of a multi-annual development programme for hydropower plants can contribute to policy decisions on SHP. Currently, a national electricity access strategy is being developed, and such a programme should be derived from this document as soon as it is finalized.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

For the moment, the Government has not yet issued a specific policy for the development of SHP in the country. Concerning the existing regulations, a clear evolution is apparent since the adoption of Law 2017-020 compared to the former Law 98-032.[21] This is particularly the case for new thresholds of capacities submitted to each regulatory regime. For example, under the old law, an SHP plant of more than 150 kW would be classified under the concession regime, whereas under the new law this limit has been raised to above 5 MW. Currently, hydropower plants with a capacity of less than 500 kW are subject to the declaration regime and those between 500 kW and 5 MW fall under the authorization regime.

The awarding of a contract may be the result of a call for tenders launched by the Government or of an unsolicited application. Whatever the applicable regime, any developer must sign a contract with the Government represented by the Minister of Energy and Hydrocarbons or ADER as the case may be. According to the Electricity Code, an environmental study is mandatory before developing a project, with the requirements depending on the categorization of the project, as determined by the National Environmental Office.

COST OF SMALL HYDROPOWER DEVELOPMENT

The average cost of SHP development in Madagascar can be estimated at 3,278 USD/kW. This estimate is deduced from three power plants with capacities of 1.3–8 MW.[13] It should be noted that estimating cost per GWh generation remains difficult to produce. For SHP plants of 60–100 kW, out of the six projects already completed, the average cost is 3,632 USD/kW. It should be noted that these estimates only account for the generation, but not transmission and distribution costs.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Currently, there is no fund dedicated specifically to the development of SHP in Madagascar. The National Fund for Sustainable Energy (FNED), created by Law 2017-021 of 19 December 2017 is dedicated to financing projects focused on the use of renewable energy, of which SHP is a part, and energy efficiency. However, the fund is not yet functional.[22] The absence of a development bank in Madagascar also makes it difficult for project developers to obtain loans.

To date, most of the SHP projects carried out have been partly financed by the European Union, KfW, the German Agency for International Cooperation (GIZ), the United Nations Industrial Development Organization (UNIDO) or by foundations receiving grants from the environment or climate change funds. Projects are initiated either by the Government or by non-governmental organizations (NGOs). For the time being, the fund managed by UNIDO through the project Improving Access to Energy for Productive Use from Small Hydropower Plants in Rural Areas in Madagascar is the only one dedicated to activities related to SHP development in Madagascar. For SHP projects in rural areas, the Government generally participates either through the National Electricity Fund or through partners in investment subsidies. The payback period is 7–10 years for projects in rural areas subsidized at 70 per cent of the initial investment.[13]

The existence of some climate change related funds or funds from the Global Environment Facility are discussed informally and at meetings, but no clear communication has reached other sectors working on mitigation, such as energy. The same is true for carbon credits, where the process is still aberrant for project developers. Awareness raising in the relevant sectors is required.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The hydrological regimes of rivers in Madagascar are being disrupted by climate change and the forecasts made 10-20 years ago do not correspond to reality any longer. As recently as 2020, several large hydropower plants were operating at only 10 per cent of their capacity during low-water periods. No statistics are available at the moment on the effect of climate change on energy consumption in Madagascar.

The climate crisis, leading to the disruption of hydrological regimes, can distort estimates. Water availability due to exponential forest degradation, at a rate of one million hectares in 13 years (between 2004 and 2017), hampers the development of SHP in the country.[23] Environmental protection must be effective, including reforestation campaigns carried out with careful monitoring. The protection of the watersheds of each SHP project is among the priorities, with accompanying measures for stakeholders dependent on its exploitation before project implementation.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In Madagascar, SHP development faces several key barriers, namely natural, financial, technical, communication and political ones. Importantly, the lack of a dedicated fund acts as a barrier to get projects off the ground. The effective operationalization of the FNED, with the concretization of the commitments of technical and financial partners, will contribute to the development of SHP projects. In addition, the establishment of a development bank would make it easier for project developers to obtain loans at reasonable rates. Systematic consultations with stakeholders in the energy sector during the budget and activity programme development phase related to the use of these funds will greatly contribute to the development of SHP.

The following points summarize the main barriers to SHP development in the country that have been identified:

- Turbines are mainly imported and not manufactured locally;
- Future risks associated with climate change as well as difficulty to attain hydrological estimates due to climate variability;
- Lack of a dedicated government fund;
- Insufficiency of rainfall monitoring systems in place;
- Lack of direct lines of communication for financing opportunities;
- Insufficient stakeholder consultation in the energy sector;
- Short election cycles incoherent with project development timescales.

The following points summarize the main enablers for the SHP sector that have been identified:

- SHP has an attractive cost per kWh compared to other renewable energy sources;
- The possibility of a new multi-annual development programme for hydropower derived from the national electricity access strategy;
- The availability of resources off-grid for SHP development.

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Malawi

Gift Chiwayula, Department of Energy Affairs

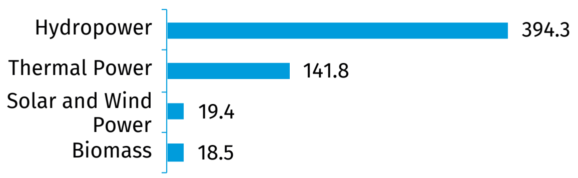
KEY FACTS

Population	19,129,952 (2020)[1]
Area	118,480 km^2 [2]
Topography	Malawi lies within the Great Rift Valley system. Lake Malawi, a body of water 580 kilometres long and lying at 460 metres above sea level, is the country's most prominent physical feature. Approximately 75 per cent of the land surface is a plateau lying at between 750 and 1,350 metres above sea level. Highland elevations rise to over 2,440 metres in the Nyika Plateau in the north and to 3,000 metres at Mount Sapitwa, the country's highest point. The lowest point is on the southern border, where the Shire River meets the Zambezi at 37 metres above sea level.[3]
Climate	The climate of Malawi is sub-tropical, with a rainy season lasting from November to April, a cool season between May and mid-August and a hot season from mid-August to November. Variations in altitude in Malawi lead to wide differences in climate, with the rainy season lasting longer in the northern and eastern mountains. Mean annual temperature is 24 °C, with average daily maximum temperatures in November reaching 29 °C, while dropping to 23 °C in July.[2]
Climate Change	In 2006, rise in average annual temperatures in Malawi was estimated at 0.9 °C over a 30-year period.[4] Several climate change models predict a countrywide increase of 1.4–3.2 °C in maximum temperature and a 1.6–2.9 °C increase in average annual temperatures by the mid-21st century, relative to the 1990s, with no significant seasonal difference in temperature rise. Over the same period, models predict a countrywide increase in annual precipitation of up to 25 per cent. On a regional level, precipitation is expected to increase in the north and decrease in the south.[5]
Rain Pattern	Precipitation is heaviest along the northern coast of Lake Malawi, where the average annual rainfall is more than 1,630 mm. Approximately 70 per cent of the country averages between 750 mm and 1,000 mm of precipitation annually.[3]
Hydrology	The main water source in the country is Lake Malawi, stretching along the eastern borders with Tanzania and Mozambique and accounting for approximately 20 per cent of the country's total area. The most significant river is the Shire (402 km), which is Lake Malawi's only outlet, flowing south into Mozambique where it meets the Zambezi.[3]

ELECTRICITY SECTOR OVERVIEW

As of June 2020, total installed capacity in Malawi amounted to 574.0 MW, of which hydropower contributed 394.3 MW (nearly 69 per cent of the total), conventional thermal power 141.8 MW (approximately 25 per cent), including 78.0 MW of emergency generators and 51.6 MW of peaking generators running on diesel, solar and wind power combined 19.4 MW (3 per cent) and thermal power from biomass 18.5 MW (3 per cent) (Figure 1). The major generating capacities are owned and operated by the Energy Generating Company (Malawi) Limited (EGENCO), with emergency generators, peaking generators and a number of other facilities including plants utilizing renewable energy sources (RES) operated by smaller private entities.[6,7,8,9,10]

Figure 1. **Installed Electricity Capacity by Source in Malawi in 2020 (MW)**



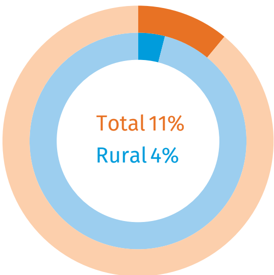
Source: Taulo et al.,[6] Chiwayula,[7] EGENCO,[8] Ministry of Finance, Economic Planning and Development,[9] USAID[10]

In 2019, annual electricity generation reached 1,887 GWh, a slight increase from the 1,808.6 GWh and 1,792 GWh generated in 2017 and 2018, respectively. However, in 2020 generation decreased across the country, with monthly generation in March 2020 only reaching 139.3 GWh, experiencing a steady decline from the 160.3 GWh generated in July 2019. As the overwhelming majority of electricity generation in

Malawi is provided by hydropower, low water levels in Lake Malawi and reduced flow in the Shire River in the second half of 2019 were responsible for this significant decline in output. Peak electricity demand and consumption have also fluctuated in recent years, with peak demand amounting to 299.6 MW in 2019 (down from 335.3 MW in 2015) and domestic consumption equalling 568.2 GWh in 2019 (down from 766.3 GWh in 2016). The main consumers of electricity in Malawi in 2019 were industry (44 per cent of total) and domestic users (36 per cent), with general use consumption (19 per cent) and exports (1 per cent) making up the remainder. At the same time, the number of individual consumers connected to the grid has more than doubled over the last decade, from 205,045 in 2011 to 439,187 in 2019. The Integrated Resource Plan developed by the Government of Malawi projects that peak demand will reach 1,158 MW by 2025 and 1,873 MW by 2030.[9]

In 2019, access to electricity decreased to just over 11 per cent nationally (4 percent in rural areas), from 18 percent (11 per cent rural) in 2018 (Figure 2).[11] Even for those with electricity access, supply is erratic and subject to frequent shortages and outages due to load shedding. The Government of Malawi has been looking to tap small-scale off-grid RES plants including solar power, wind power and small hydropower (SHP) to meet electricity demand in isolated areas where grid extension is difficult, aiming to increase nationwide access to electricity to 30 per cent by 2030.[9,12]

Figure 2. **Electrification Rate in Malawi in 2019 (%)**



Source: World Bank[11]

Electricity generation in Malawi is primarily carried out by EGENCO, created after the unbundling of the Electricity Supply Cooperation of Malawi (ESCOM). ESCOM, which previously was the sole provider of on-grid electricity in Malawi, has been unbundled into three companies, with EGENCO responsible for generation and operating all the major hydropower plants in the country. Power Market Limited (PML) is responsible for buying the generated electricity and ESCOM itself is responsible for transmission and distribution. Additionally, some generation is carried out by independent power producers (IPPs) that include Mulanje Hydro Limited as well as Aggrekko, which operates the emergency diesel-fuelled generators.[7]

Electricity tariffs differ depending on the type of customer and the phase supply being used and are lower than the tariffs in the South African Development Community (SADC) region and other neighbouring countries. The tariffs are regulated by the Malawi Energy Regulatory Authority (MERA), which is also the main regulator of all other fuels.[13] Tariffs for domestic, commercial and industrial users as of 30 March 2020 are displayed in Table 1.

Table 1. **Electricity Tariffs in Malawi in 2021**

Type of customer	*Description*	*Tariff (USD/kWh)*
Domestic	Single phase supply	0.0978
	Three phase supply	0.1420
Commercial	Single phase supply	0.1471
	Three phase supply	0.1627
Industrial	On-peak	0.1790
	Off-peak	0.0621

Source: ESCOM[14]

The Government of Malawi is making efforts to increase the capacity of generated electricity through upgrades to existing power plants and the construction of new ones, planning to increase annual generation to 3,300 GWh by 2030. Feasibility studies are currently underway for various energy sources, including hydropower, coal, biomass, geothermal power and wind and solar power. As of 2020, the Government had signed 11 power purchase agreements (PPAs) with developers to install an additional 328 MW of capacity by 2027. Plans are also underway to connect to the Zambian and Tanzanian power grids, providing investors with access to regional power markets including the Southern Africa Power Pool (SAPP). Programmes such as the Malawi Rural Electrification Programme (MAREP) and Malawi Electricity Access Project (MEAP) are ongoing with the aim of expanding electricity access in both rural and urban areas.[8,9]

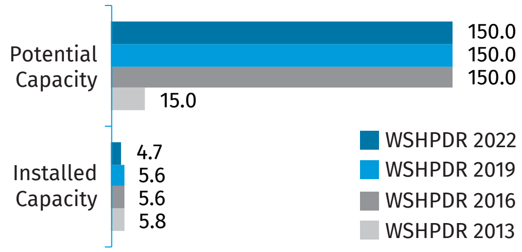
In general, the electricity sector in Malawi faces many challenges, including lack of IPPs and lack of financial resources and clear policy guidelines to promote private investors in the electricity sector. Additionally, shifting weather patterns have been creating instability in hydropower generation, requiring the procurement of emergency diesel generators in order to meet demand. In 2013, the Millennium Challenge Corporation provided the Government of Malawi with funds totalling USD 350.7 million in order to help overcome some of these challenges.[15]

SMALL HYDROPOWER SECTOR OVERVIEW

In Malawi, SHP is defined as hydropower plants with an installed capacity of less than 5 MW. As of 2021, total installed capacity for SHP plants under 5 MW in Malawi was approximately 4.7 MW, while SHP capacity up to 10 MW was 12.9 MW.[7,16,17,18] Based on studies of previous years, proven SHP potential amounts to at least 7.7 MW and theoretical potential has been estimated at 150 MW.[19,20] This indicates that approximately 4 per cent of the country's known theoretical SHP potential has been developed so far. Compared to data from the *World Small Hydropower Development Report*

(WSHPDR) 2019, the installed capacity for SHP up to 5 MW has decreased marginally as more precise data on operational plants became available and also due to the replacement of older SHP plants with a new SHP plant of over 5 MW installed capacity.[21]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Malawi (MW)**



Source: Ministry of Energy and Mining,[3] Taulo et al.,[6] Chiwayula,[7] Gilkes,[16] Ministry of Energy,[17] Jonker Klunne,[18] Kaunda et al.,[19] *WSHPDR 2019*,[20] *WSHPDR 2013*,[21] *WSHPDR 2016*[22]

Note: Data for SHP up to 5 MW.

As of 2021, the Wovwe SHP plant in Karonga is the only grid-connected SHP under 5 MW operating in Malawi, with an installed capacity of 4.35 MW.[23] The 8.25 MW Ruo-Ndiza SHP plant in Mulanje, another grid-connected power plant that falls under the up to 10 MW definition of SHP, was operational as of 2020 and is the largest SHP project in Malawi. The plant, located at the Lujeri Tea Estates, replaced two old SHP plants of 0.84 MW and 0.46 MW at the same location.[16,18] Additionally, several mini- and micro-hydropower plants are operational on isolated mini-grids, including two plants of 60 kW and one 100 kW plant that are part of the Mulanje Electricity Generating Agency (MEGA) mini-grid in Bondo, the 70 kW Chipopoma SHP plant and the 10 kW Kavuzi SHP plant.[17,24,25] Operational SHP plants are listed in Table 2.

Ongoing SHP development includes the construction of another 4.5 MW power plant at the Wovwe site to bring the total installed capacity of the plant to 9.5 MW.[23] Additionally, upgrades have been planned to the MEGA group of SHP plants by a non-governmental organization called Practical Action to bring the entire network to 2 MW of capacity. Components of the Practical Action programme originally included the development of several new SHP plants of up to 500 kW capacity, aiming to reach an annual SHP generation target of 15.6 GWh, with funding provided by the Global Environment Facility (GEF) and the Government of Scotland. Completed upgrades have brought the MEGA mini-grid to its current capacity of 220 kW. Also, a grant was awarded by EEP Africa to Practical Action to develop an SHP plant at Usingini with an initial planned capacity of 300 kW and a total potential capacity of 5 MW. However, Practical Action has recently reduced its presence in Malawi and additional MEGA upgrades as well as the Usingini project have been delayed, with the latter in advanced stages of planning.[7,17,24] Ongoing SHP projects are listed in Table 3.

Table 2. **List of Operational Small Hydropower Plants in Malawi**

Name	*Location*	*Capacity (MW)*	*Head*	*Plant type*	*Operator*	*Launch year*
Ruo-Ndiza	Mulanje, Lujeri Tea Estate	8.250	230	Run-of-river	Mulanje Hydro Ltd	2020
MEGA 3	Bondo, Mulanje	0.100	N/A	Run-of-river	MEGA LTD	2019
Kavuzi	Nkhatabay	0.010	N/A	Run-of-river	Kavuzi Electricity Generation and Supply Association	2018
MEGA 2	Bondo, Mulanje	0.060	N/A	Run-of-river	MEGA LTD	2016
Chipopoma	Mantchewe, Livingstonia	0.070	N/A	Run-of-river	Community-owned	2015
MEGA 1	Bondo, Mulanje	0.060	50	Run-of-river	MEGA LTD	2011
Wovwe SHP	Karonga	4.350	N/A	Run-of-river	EGENCO	1996

Source: Chiwayula,[7] Gilkes,[16] Ministry of Energy,[17] Jonker Klunne,[18] EGENCO,[23] MEGA,[24] GEF SGP[25]

Note: SHP plants of up to 10 MW.

Table 3. **List of Ongoing Small Hydropower Projects in Malawi**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Type of plant*	*Developer*	*Planned launch year*	*Development stage*
Wovwe II	Karonga	4.5	N/A	Run-of-river	N/A	2023–2023	Feasibility study completed
Usingini	Nkhatabay	5.0	150	Run-of-river	N/A	N/A	Feasibility study and design plans completed

Source: Chiwayula,[7] Ministry of Energy,[17] EGENCO[23]

Several other previously functional SHP plants are currently out of operation, including one in Matandani maintained by the Malawi Industrial Research and Development Centre, as well as the Kongwe and Malosa SHP plants. These sites, with a total installed capacity of 358 kW when operational, could be potentially refurbished. Additionally, the Malawi Rural Electrification Programme (MAREP) Master Plan Study carried out by the Japan International Cooperation Agency (JICA) identified 33 potential SHP sites, including 11 promising sites with a total estimated potential capacity of 345 kW.[7,18,26] Several potential sites for SHP plant construction or refurbishment are listed in Table 4.

Table 4. **List of Selected Potential Small Hydropower Sites in Malawi**

Name	*Location*	*Potential capacity (kW)*	*Type of site (new or refurbishment)*
Matandani	Neno district	28	Refurbishment
Katowo	Hewe River	45	New
Ruarwe	Lizunkhuni River	50	New
Nthalire	Choyoti River	60	New
Sandama	Nswazi River	75	New

Source: Chiwayula,[7] Jonker Klunne,[18] JICA[26]

RENEWABLE ENERGY POLICY

The new National Energy Policy (NEP) of Malawi, issued in 2018, and the Malawi Renewable Energy Strategy, developed in 2017, both provide for the development of RES in the country. The 2018 National Energy Policy aims to increase hydropower capacity, extend the national grid as well as expand the implementation of mini-grids in remote areas based on hydropower generation. Increases in hydropower capacity and output are to be achieved through the construction of new plants by IPPs as well as upgrades to existing plants. While hydropower is expected to provide the bulk of the country's generation, the Policy also outlines diversification into other energy sources including solar power, wind power and coal.[27]

The Malawi Renewable Energy Strategy includes the following elements:

- Incentives for RES technologies including tax waivers, which have been put in place starting with the 2020/2021 fiscal year to reduce the cost of RES development;
- Promotion of research and development in RES and increasing the number of undergraduate and graduate courses in RES offered by technical universities in Malawi, as well as training programmes in RES offered by other stakeholders;
- Awareness campaigns by various media organizations to promote RES;
- Establishment of the Malawi Renewable Energy Partnership Group (MREPG) in 2018 to oversee the implementation of RES projects in Malawi and provide coordination for RES stakeholders;
- The implementation of feed-in tariffs (FITs) and a PPA framework for RES, still in development stages.[28]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP development in Malawi is covered by regulations applied to hydropower in general, outlined in the National Energy Policy. Legislation on hydropower in Malawi differentiates between grid-connected and stand-alone (off-grid) projects. In the case of grid-connected projects, the developer is given the generation licence only, after meeting the necessary technical, safety and environmental requirements, which include an environmental impact assessment. Power from grid-connected hydropower IPPs is sold to Power Market Limited and distributed exclusively by ESCOM. In the case of off-grid projects, hydropower plants (including SHP plants) can operate as a mini-grid where the developer is given generation, transmission and distribution licences after meeting the necessary requirements. Some of the requirements are that the system should be of the same standard as the main grid for easy integration and sell electricity at a tariff approved by the Malawi Energy Regulatory Authority.[27,28]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Financial support for SHP development in Malawi is provided by a variety of international and local entities. International organizations providing funding for SHP have included the World Bank, the United Nations Development Programme (UNDP), the European Union Energy Facility, the Organization of the Petroleum Exporting Countries (OPEC) Fund for International Development and the Global Environmental Facility Small Grants Program (GEF SGP).[7,17,24,25] Bilateral support for RES and hydropower development has been provided by the United States Government through the United States Agency for International Development (USAID) and the Millennium Challenge Corporation (MCC), while the Japan International Cooperation Agency (JICA) and the Scottish Government have supported projects specifically focused on SHP.[10,15,26] Local funding for SHP has also been provided by the Ministry of Energy as well as by private investors and international non-governmental organizations with a presence in the county.[17]

COST OF SMALL HYDROPOWER DEVELOPMENT

Costs of SHP development in Malawi have varied considerably based on project size and location. The recently commissioned Ruo-Ndiza 8.25 MW SHP plant carried a total project cost of USD 16 million, or 1,939 USD/kW.[30] The Usigini SHP project with a preliminary capacity of 300 kW and eventual planned capacity of 5 MW was initiated with funds totalling USD 328,125 (1,093 USD/kW), but has been affected by severe delays.[17] On the other end of the spectrum, JICA's Master Plan Study for MAREP estimated construction costs of between USD 299,890 and USD 1,213,930 for 11 prospective sites of 5–75 kW, averaging between 12,629.2 USD/kW and 94,690 USD/kW.[26] From these figures it becomes clear that micro-hydropower projects in Malawi are significantly more expensive than projects in the 1–10 MW range.

EFFECT OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Malawi is heavily dependent on hydropower for electricity production and has already been experiencing severe generation shortfalls due to low water levels in Lake Malawi and the Shire River, particularly in 2020.[9] Extreme fluctuations in rainfall have also caused flooding, causing damage to hydropower infrastructure. Projections of future weather pattern changes by the mid-21st century predict an increase in rainfall in the northern part of the country (up to 40 per cent during the wet season) and a decrease in the south (up to 75 per cent during the dry season). Significantly, several climate models predicted an increase in runoff of nearly 182 per cent during the wet season in the northern part of the country and a moderate 11 per cent decline in the south.[5] These data suggest that SHP in Malawi is threatened not only by water scarcity but also by the increased likelihood of flood damage, particularly in the north.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Some of the key barriers to SHP development in Malawi include:

- The lack of investors to develop SHP due to limited financing capacity;
- Environmental degradation, with deforestation from logging and farming activities upstream and near the river banks leading to rivers drying up;
- Lack of human capital to build and operate SHP plants in Malawi;
- Lack of information and awareness among communities on the benefits of SHP;
- Old electricity infrastructure vulnerable to extreme weather events;
- Vandalism of infrastructure such as transformers.

Enablers for SHP development include:

- Acute demand for additional generation capacity due to very low electrification rate in the country;
- Availability of financing mechanisms;
- Tax exemption on all RES equipment;
- Availability of detailed data on potential SHP sites and large untapped SHP potential;
- Existing political will to develop the energy sector.

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Mauritius

Dinesh Surroop and Doorgeshwaree Jaggeshar, University of Mauritius

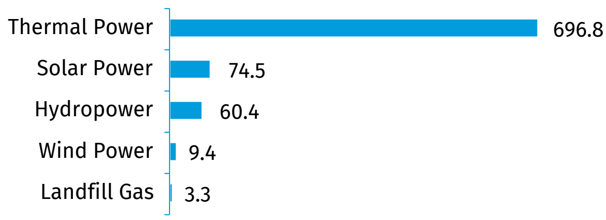
KEY FACTS

Population	1,265,475 (2019)[1]
Area	1,868 km^2 [1]
Topography	The island, located in the south-west of the Indian Ocean, was formed by volcanic activity. It has sandy beaches and fringing coral reefs, which surround most of the 322 kilometres of its coastline. The topography is categorized by undulating plains in different parts of the island and the highest point is 828 metres, which is located at Petite Riviere Noire.[2,3]
Climate	Enjoying a mild and tropical weather, the climate in Mauritius is divided into two seasons, namely summer and winter. Summer is warm and humid and it runs from November to April and winter is cool and dry lasting from June to September. October and May are the transition months. The mean temperature during summer is 22.7 °C; the climate is moderately hot and moist. During the winter the average temperature is 18.7 °C, with a relatively chilly and drier climate.[4,5]
Climate Change	Observed climate change impacts have indicated a warming trend on the island, with the average temperature at all stations rising at the rate of 0.15 °C per decade and has already risen by 0.74 1.2 °C when compared to the 1961-90 long term mean. Meanwhile a diminishing trend in annual rainfall has also been shown. In spite of the decreasing number of rainy days, the recurrence of extreme climate events, overwhelming downpours and storms with strengths equivalent to tropical cyclones or higher has expanded over the last two decades. Future projections of climatic changes anticipate a decrease of approximately 10 20 per cent in rainfall and a temperature increase of 2 °C.[2,4,6]
Rain Pattern	The annual precipitation for the year 2020 was approximately 1,993 mm, indicating a decrease by 6 per cent from 2019. The annual average rainfall from 1971 to 2000 amounted to 2,010 mm. Despite no fixed rainfall period, rainfall generally occurs during summer months, with an annual average summer rainfall of 1,322 mm (1971–2000). In the winter season, the annual average rainfall is 666 mm.[4,7]
Hydrology	The hydraulic system of Mauritius is composed of 20 main rivers with the Grand River South-East, located in the central-eastern region, having the longest length of approximately 28 kilometres. Other primary waterways include the Black River, Post River, Grand River North-west and Rempart River. Mauritius also has a few waterfalls and 10 main man-made reservoirs. The reservoirs amount to a total capacity of approximately 67.4 m^3.[2,8]

ELECTRICITY SECTOR OVERVIEW

In 2019, the total power plant installed capacity in the island amounted to 844.3 MW (Figure 1), while the total effective capacity was 771.9 MW. Electricity generation in 2020 reached 2,882 GWh (Figure 2), with the peak power demand reaching 494 MW.[9] The bulk of electricity production in Mauritius comes mainly from fossil fuels, namely coal and oil, followed by renewable energy sources including bagasse, hydropower, solar power, wind power and landfill gas. In 2020, coal and oil represented 76 per cent in the electricity production mix and the rest (24 per cent) was met by renewable energy at 688 GWh.[8] Hydropower represented approximately 4 per cent of all generation, at 115.8 GWh.[7]

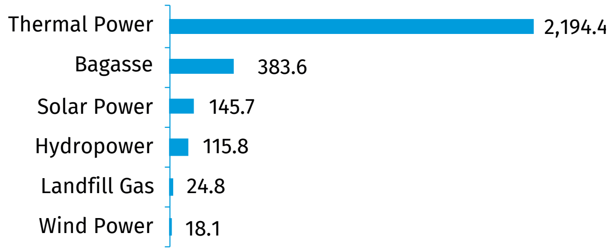
Figure 1. **Installed Electricity Capacity by Source in Mauritius in 2019 (MW)**



Source: MREPU,[9] CEB[15]

Note: According to MREPU, bagasse is included in the thermal installed capacity figures.

Figure 2. **Annual Electricity Generation by Source in Mauritius in 2020 (GWh)**



Source: CSO[7]

In the 1950s, the state-owned Central Electricity Board (CEB) was the only entity responsible for generating, transmitting and distributing electricity across the island until the sugar industry-affiliated power plants initiated the sale of electricity produced from bagasse to the CEB. This initiative was further encouraged by the Bagasse Energy Development Programme (BEDP) in 1991 and the Multi-Annual Adaptation Scheme 2006–2015.[10] Today, electricity in Mauritius is produced by the CEB and Independent Power Producers (IPPs). The share of the CEB's production in 2019 was 45 per cent, while the remaining 55 per cent was purchased from IPPs, which are mainly from the sugarcane industry.[8]

Mauritius has achieved an electrification rate of 100 per cent. The national rural electrification programme was established in 1983, allowing the connection of 153 villages and housing estates to the grid network. With an enlarged economy, Mauritius now enjoys extensive power provision infrastructure and the advantages of a steady power supply.[11]

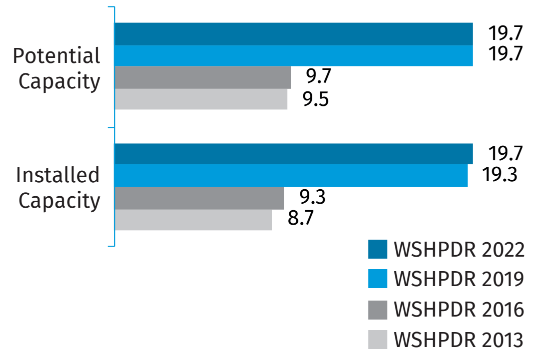
For most power projects, the Government of Mauritius looks for competitive international bids and favours collaboration between regional private bodies and international organizations. In 2017, the CEB Act (1963) was amended to permit CEB (Green Energy) Co Ltd, an entirely owned subsidiary of the CEB, to participate in power generation from renewable energy sources.

In 2019, the CEB's tariff programme had 24 different types of tariffs, ranging from 3.16 MUR/kWh (0.074 USD/kWh) for low-end residential consumers to a flat rate tariff of 10.01 MUR/kWh (0.023 USD/kWh) for commercial energy users.[12] It should be noted that special consideration has been made on social grounds for household electricity consumption. For instance, the Social Tariff 110A is applicable to households receiving the government social allowance, registered as socially vulnerable or registered under Tariffs 110 and 120 (excluding small-scale distributed generation owners) and meeting the required monthly consumption conditions.[13] However, it should be noted that electricity tariffs are not wholly cost-effective in Mauritius as industrial tariffs are subject to cross-subsidization. With no independent power utility regulator, the CEB is solely responsible for setting the tariffs. For this reason, proper planning is required for restructuring the tariff system, emphasizing the need for cost-effective production during capacity expansion.[14]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no formal definition of small hydropower (SHP) in the country. This chapter uses the 10 MW definition. In 2020, the installed capacity of SHP in Mauritius amounted to 19.69 MW, indicating an increase of 0.35 MW compared to the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 3). The known potential capacity has not changed, indicating that the full known SHP potential has been exploited in the country. At present, there are 11 SHP plants including the recent Bagatelle Dam, which was commissioned in 2019 (Table 1). All SHP plants in the country, except for Riche en Eau and Bois Cherie, are owned by the CEB.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Mauritius (MW)**



Source: CEB,[15] MEPRU,[16] WaterPower Magazine,[17] Bowers et al.,[18] *WSHPDR 2013*,[19] *WSHPDR 2016*,[20] *WSHPDR 2019*[21]

Apart from the Bagatelle Dam, Midlands Dam and La Nicoliere, the operational lifetime of the remaining SHP plants exceeds 50 years. The most ancient is the Reduit (now A.I.A.) SHP plant, which was established in 1906 but refurbished in 1984. Major hydropower refurbishments projects included the refurbishment and upgrading of the generating unit in the Magenta plant, which was expected to be completed by November 2019 (Table 2).[15] Although not an SHP project as such, but rather a project to increase the capacity of the 28 MW Champagne hydropower plant, the Sand Souci dam is to be fitted with a labyrinth type fuse gate, effectively increasing the generation of the nearby plant by 3 GWh.[22]

Table 1. **List of Operational Small Hydropower Plants in Mauritius**

Name	Capacity (MW)	Head (m)	Plant type	Operator	Launch year
Bagatelle Dam	0.35	–	Run-of-river with dam storage	CEB	2019
Midlands Dam	0.35	–	Run-of-river with dam storage	CEB	2013
La Nicoliere	0.35	–	–	CEB	2010

Name	Capacity (MW)	Head (m)	Plant type	Operator	Launch year
La Ferme	1.20	127	Run-of-river	CEB	1988
Le Val	4.00	183	Run-of-river with dam storage	CEB	1961
A.I.A (previously Reduit)	1.20	50	Run-of-river	CEB	1984
Ferney	10.00	123	Run-of-river	CEB	1971
Cascade Cecille	1.00	76	Run-of-river	CEB	1963
Magenta	0.94	45	Run-of-river with dam storage	CEB	1960
Riche En Eau	0.20	–	–	Private	–
Bois Cherie	0.10	–	Run-of-river with dam storage	Private	–

Source: CEB,[15] MEPRU,[16] WaterPower Magazine,[17] Bowers et al.[18]

Table 2. **List of Planned Small Hydropower Projects in Mauritius**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Developer*	*Planned launch year*	*Stage of development*
Magenta	–	0.94	45	Run-of-river with dam storage	Andritz Hydro SA	2022	Refurbishment

Source: MEPRU[16]

A full feasibility study determining potential SHP sites for setting up mini- and micro-hydropower plants is yet to be completed. There is a debate around whether the country's hydropower potential has been entirely exploited, as one modelling exercise claimed that full potential has been reached, whereas proponents of SHP in the country contested this study, arguing that "the predictions did not fully consider mini- and micro-hydropower plants, which have gained momentum and been helpful in reducing pressure on the main grid".[10,23] The Integrated Energy Plan (2013–2022) indicated the Government's interest in developing mini- and micro-hydropower plants in viable locations. However, with the exception of the Bagatelle Dam, no other initiative was taken in this direction.

RENEWABLE ENERGY POLICY

In 2008, the Government brought forward the Mauritius Sustainable Island (MID) policy, strategy and action plan with the vision of delivering sustainable growth and making Mauritius an example of sustainable development. The objective of the MID project was to achieve 35 per cent of renewable energy generation by 2025, by exploring additional economic incentives to advance the development of renewable energy resources. In parallel to the MID plan, financial support was obtained from the Government for several renewable energy projects. These include the setting of a 9.4 MW wind farm at Plaine des Roches, which was commissioned in 2015, and the installation of solar photovoltaic farms amongst others.[24]

Following the Integrated Energy Plan (IEP) 2003–2012, it was noted that little advancement occurred in the introduction of renewable energy technologies in the country. Hence, the Government came up with the Long-term Energy Strategy 2009–2025 with the objectives to reduce dependency on fossils fuels, promote long-term sustainable development and augment the share of renewable energy in the electricity mix to 35 per cent by 2025. The renewable energy development pathway advocated laid emphasis on an increasing share of bagasse-based energy, while setting targets for fossil fuels and green energy.[16]

Another IEP (2013–2022) was adopted by the CEB with the goal of ensuring a secure electricity future in Mauritius. According to the new IEP, the CEB has already begun feasibility studies to identify potential sites for further hydropower development.[25] The master plan's pillar has been to maximize the use of the current power grid, keep energy costs down, promote demand-side management and create opportunities for the private sector. According to the IEP, a 20 MW wind power plant would be installed every three years after 2017 and a 10 MW solar power plant every three years after 2013. However, the plan to install any 20 MW wind farm is yet to be accomplished.[26]

The CEB Small-Scale Distributed Generation (SSDG) Net-Billing Scheme was announced in the 2018/19 budget speech. Under the scheme, residential customers (who consume up to 100 kWh per month and are in tariff categories 110, 120, and 140) will generate their own electricity as part of a project aimed at promoting renewable energy. The SSDG project is to be implemented in three stages over the course of three years.[27] The scheme employs a net-billing system and 2,500 residential customers will be able to receive up to 100 kWh of electricity free of charge per month for the next 20 years, depending on their consumption. Taking current tariffs into account, the selected customers consuming less than 100 kWh per month will have their electricity completely free.[22]

In the energy sector, the Government has been working on legal and structural reforms. The Mauritius Renewable Energy Agency (MARENA) was established by the Government in 2016 to encourage the use of renewable power in the island.[28] In 2019, the Government came up with the Renewable Energy Roadmap 2030 for the Electricity Sector, where bagasse is the predominant renewable resource followed by solar power, waste-to-energy, hydropower and wind power.[9] Under the 2030 roadmap, the share of hydropower in total electricity generation should decrease from 4.4 to 2.5 per cent by 2030.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Securing a licence of Environmental Impact Assessment (EIA) is essential for mini- and micro-hydropower projects. The Government's strategy has been to enable Small Independent Power Producers (SIPPs), whether residential, industrial or commercial, to join the electricity supply market by installing small generating units of mainly solar photovoltaics and wind power. A grid code has been implemented to allow SIPPs generating below 50 kW of electricity for their personal use to feed any excess into the national grid system. To facilitate such a scheme, government initiatives, such as removal of a standby charge on renewable energy, were introduced.[16]

COST OF SMALL HYDROPOWER DDEVELOPMENT

Data for cost estimates of SHP development in the island are not available. However, a cost of approximately MUR 7.1 billion (USD 170 million) has been estimated for the construction of a new dam of 14.3 m^3 capacity.[29] For hydropower plants in Mauritius, the levelized cost of energy is approximately 0.020 USD/kWh, including other associated costs, such as maintenance, refurbishment and upgrading of power plants.[9]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Funding for projects in the hydropower sector depends on the readiness of the project and the ability of the developer to implement the project. The water resources unit, under the Ministry of Finance and Economic Development, provides financing facilities in the form of grants. Estimates for the year 2017/2018 indicate an allocation of MUR 487 million (USD 11.4 million) for the construction of dams on the island.[29]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The longer drought period and decreasing rainfall trend pose a challenge to the availability of water resources in the country and thus for SHP development.[9] However, hydropower development is not only subjected to climate effects. As a small developing island country, governmental priority is being given to water use for household consumption purposes, rather than hydropower generation.[9,30]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Compared to other power generating units, hydropower plants are flexible to fluctuating electricity network demand. Hydropower plants have the capacity to quickly increase or decrease output and can provide electricity at peak demand conditions.[18] Recommendations suggest a possible revamping of the hydropower sector in Mauritius through the deployment of mini- and micro-hydropower plants or pumped storage plants to cater to the intermittency of renewable energy sources.[9] The potentiality of further hydropower development in the island is known to be limited. Exploring mini-and micro-hydropower is still possible and the Government is keen to explore this potential across the island. The CEB has already begun feasibility studies to identify potential sites for further hydropower development. However, while revamping any hydropower facilities is possible, striking the optimum balance between hydropower uses and environmental impact on the restricted island ecosystem is essential.

The following points summarize the main barriers to SHP development in Mauritius that have been identified:

- Only some locations possess the natural characteristics for exploitation (most cost-effective sites have been explored);
- Potable supply, agriculture and electricity generation compete for the water stored in reservoirs;
- Dependency of the technology on rainfall, while climate change is influencing rainfall patterns;
- The potential to expand the existing dam capacity is limited;
- High cost associated with hydropower plant construction;
- Lack of resources to conduct feasibility studies;
- Environmental impact of SHP.

The following points summarize the main enablers for SHP development that have been identified:

- Government feasibility studies are underway to determine whether new potential will be available.

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Mozambique

Laura Stamm, International Center on Small Hydropower (ICSHP)

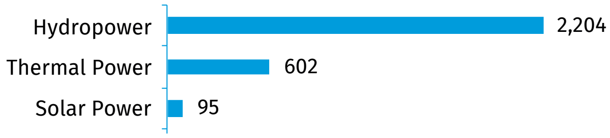
KEY FACTS

Population	32,163,045 (2021)[1]
Area	799,380 km² [2]
Topography	Mozambique is a topographically diverse country. The northern and western regions are predominately mountainous, while low lands cover the southern regions. There are five distinct highland regions. The Lichinga Plateau occupies the north-westernmost area along the border with Tanzania, followed by the Angonia Highlands on the north-western border with Malawi. The Maravila Highlands are found in the western pocket of land on the border with Zambia and just underneath is the Chimboio Plateau along the western border with Zimbabwe. The highest point in the country, Mount Binga at 2,436 metres, is found in the Chimboio region. The Mozambique Plateau occupies most of the northern interior, leaving a very narrow coastal plain in the north-east. In the south and south-east, where the Mozambique Plains are found, are the lowest elevations in the country, while small hills are found in the south-westernmost region.[2]
Climate	The country's climate is mostly tropical, though the south is slightly cooler than the north. The hottest temperatures, often reaching above 30 °C, are found along the north-eastern coastline especially during the summer months between December and February. The coldest temperatures, reaching 10 °C, are found in the highest altitudes along the western borders. Humidity varies greatly between regions. The northern and north-eastern regions are especially humid all year while the south is drier with a small semiarid area in the south-east.[2]
Climate Change	There has been a trend of rising temperatures in Mozambique in the past decades, which is expected to continue. The country is vulnerable to extreme weather events, particularly droughts, flooding and cyclones. These types of events have been on the increase since the 1970s. In the upcoming decades, droughts and floods are expected to become more intense and cyclones more prevalent.[3]
Rain Pattern	Rainfall varies greatly between regions and areas of the country. The northern and north-eastern regions are the wettest, with an average annual rainfall of between 1,000 mm and 1,780 mm with some pockets of over 2,000 mm. The west and southern interior receive the least rainfall, with annual averages between 600 mm and 800 mm. The semiarid region in the south-west receives an average of 300 mm in rainfall per year. The wet season throughout the country is between November and February, while the dry season is between April and October.[2]
Hydrology	Mozambique is a water-rich country. The major rivers flow eastwards from the western highlands to drain into the Mozambique Channel and Indian Ocean. The largest river in the country is the Zambezi flowing 819 kilometres through the central region. The major rivers in the north include the Rovuma that creates the country border with Tanzania, the Messalo, Lurio and Ligonha. The major rivers in the south include the Buzi, Save, Changane and Limpopo. Rivers tend to have a seasonal flow, flooding during the end of the wet season and are slow during the end of the dry season. The largest lakes are along the border with Malawi including Lake Nyasa and Lake Chilwa.[2]

ELECTRICITY SECTOR OVERVIEW

In 2020, the total installed capacity in Mozambique was 2,915 MW. Of this, hydropower accounted for 2,204 MW (just under 76 per cent), thermal power for 602 MW (21 per cent), solar power for 95 MW (3 per cent) and biomass for 14 MW (0.5 per cent) (Figure 1).[4] The country's energy mix has been dominated by hydropower since the opening of the Cahora Bassa plant in 1974. In the past few years, the country has been diversifying into other renewable energies, with strong focus on solar power. The country's first large-scale solar power plant, with an installed capacity of 40 MW, opened in 2019 and is located in Mocuba. Shortly after, in 2020, an additional 41 MW solar power plant was commissioned in Metero by French-owned power producer, Neoen.[5]

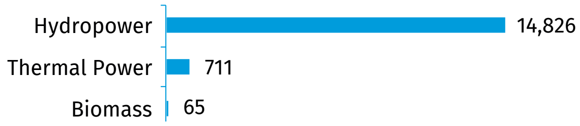
Figure 1. **Installed Electricity Capacity in Mozambique by Source in 2020 (MW)**



Source: IRENA[4]

The total electricity generated in 2019 in Mozambique was 15,603 GWh. Of this, hydropower generated 14,826 GWh (95 per cent), thermal power 711 GWh (over 4 per cent) and the last percentage was split between 65 GWh of biomass and 2 GWh of solar power (Figure 2).[4] As more recent data are not available, this does not reflect the electricity generated by the new Mocuba solar power plant which has an estimated generation capacity of 79 GWh/year.[5]

Figure 2. **Annual Electricity Generation in Mozambique by Source in 2019 (GWh)**



Source: IRENA[4]

The Electricity Law of 1997 first allowed independent power producers (IPPs) to participate in the supply of electricity in Mozambique. Prior to this, state-owned Electridade de Moçambique (EDM) was the main electricity supplier, with the exception of Hidroeléctrica de Cahora Bassa S.A. (HCB), and still holds a significant market share of electricity generation. HCB, which operates the one large hydropower plant with an installed capacity of 2,075 MW was once mostly owned by REN of Portugal, but since 2007 the majority ownership has been transferred to the Government of Mozambique, which currently owns over 92 per cent of the shares. In recent years IPPs have played an important role in the electricity sector. The largest IPPs include Central Termoelectrica de Ressano Garcia (CTRG) with an installed capacity of 175 MW, Gigawatt Ressano Garcia with 110 MW, Nacala floating powership with 102 MW, Kuvaninga with 40 MW and Aggreko with temporary contracts of 122 MW and 107 MW. As EDM is responsible for the distribution and transmission of electricity in the county, these IPPs operate within power purchase agreements (PPAs) with EDM.[6]

The Ministry of Natural Resources and Energy (MIREME) is responsible for supervising operation and development in the electricity sector. The Energy Regulatory Authority (ARENE) is the organization responsible for regulating the sector. EDM makes the final approval of tariffs for end customers. Different tariffs are determined for five different types of consumers: low voltage, major consumers of low voltage, medium voltage, agriculture medium voltage and high voltage.[6] Social tariffs with a special rate are provided for some low-voltage customers for 0.97 Mt/kWh (0.015 USD/kWh). The regular tariffs prices for all other customers are listed in Table 1.[7]

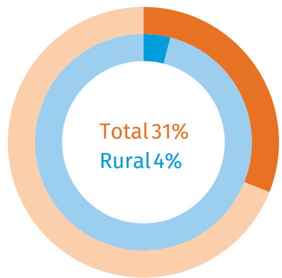
Table 1. **Electricity Tariffs in Mozambique**

Type of consumer	*Tariff (MZN/kWh (USD/kWh))*
Low voltage households:	
< 200 kWh	6.00 (0.094)
200–500 kWh	8.49 (0.130)
> 500 kWh	8.91 (0.140)
Major low voltage	5.74 (0.090)
Medium voltage	4.78 (0.075)
Medium voltage (agricultural)	2.72 (0.043)
High voltage	4.70 (0.074)

Source: EDM[7]

The electrification rate of Mozambique in 2020 was just under 31 per cent, which includes an urban rate of 75 per cent and a rural rate of just above 4 per cent (Figure 3).[8] The current policy objectives of the Government and EDM are focused on rural electrification and increasing the number of new users on a continuous basis. While many extensions have been carried out since 2007, there is still much to be accomplished in order to meet targets. The most recent national plans include targets of reaching a 50 per cent electrification rate by 2023 and universal access by 2030. To push this agenda, the Government of Mozambique partnered with the World Bank to draw up the National Electrification Plan in 2018. As a result of the plan, the World Bank approved a USD 82 million direct grant along with a USD 66 million grant through a Multi Donor Trust Fund (MDTF) to expand and densify the national grid and implement off-grid solutions in some remote places.[9]

Figure 3. **Electrification Rate in Mozambique in 2020 (%)**



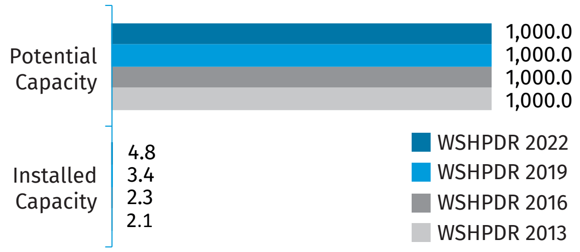
Source: World Bank[8]

Improving infrastructure quality is another main focus in the energy sector. Due to structural inefficiencies and far distances between generation and consumption, distribution and transmission losses are substantial. In 2017, losses amounted to approximately 26 per cent. In response, projects to strengthen the transmission network have been undertaken and will continue to be important. Furthermore, the current capacity will not be sufficient to bring electricity to the whole population. To address this, several sites have been identified for future projects. Many of the large-scaled projects are with hydropower, namely Mphanda Nkuwa (1,500 MW), HCB North bank (1,245 MW), Lupata (600 MW), Boroma (200 MW) and Lurio (120 MW). Solar power projects are also substantial, including 43 on-grid projects that amount to 599 MW and 343 smaller off-grid projects to bring electricity to remote communities.[6]

SMALL HYDROPOWER SECTOR OVERVIEW

In Mozambique, small hydropower (SHP) is classified as plants with an installed capacity up to 10 MW.[10] In 2017, the total installed capacity of SHP up to 10 MW was at least 4.77 MW, while the total potential capacity of SHP is estimated to be 1,000 MW.[6,11] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019,* installed capacity has increased by 1.4 MW due to new information and the potential capacity has remained the same (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Mozambique (MW)**



Sources: ALER,[6] *WSHPDR 2019,*[11] *WSHPDR 2016,*[12] *WSHPDR 2013*[13]

The country's greatest hydropower potential lies in the Zambezi River basin at sites such as Cahora Bassa North and Mphanda Nkuwa. The overall hydropower potential in the country is estimated to be approximately 19,000 MW.[14] Much of the potential is large hydropower, but at least 5 per cent of it is SHP. Most of the SHP already installed is below 1 MW, with the exception of Pequenos Libombos (1.5 MW) and Cuamba (1.1 MW) (Table 2).[6]

Table 2. **List of Selected Existing Small Hydropower Plants in Mozambique**

Name	*Installed capacity (MW)*	*Operator*
Pequenos Libombos	1.50	IPP
Cuamba	1.10	EDM
Lichinga	0.76	EDM
Rotanda	0.63	FUNAE
Majaua	0.60	FUNAE
Muôha	0.10	FUNAE
Sembezeia	0.06	FUNAE
Chiuraírue	0.02	FUNAE

Source: ALER[6]

SHP plants in Mozambique are particularly concentrated in the centre of the country, more specifically in the Provinces of Manica, Tete and Zambézia. The main players involved in the SHP sector are EDM and the country's Energy Fund, FUNAE. There are additional SHP plants with capacities below 30 kW that were funded and provided technical assistance by the German Corporation for International Cooperation (GIZ) and are operated by local private entities. Some non-governmental organizations including Practical Action and the Association Kwaedza Simukai Manica (AKSM) have also been involved in the funding and execution of other SHP projects.

FUNAE is a publicly owned organization that focuses on small, low-cost power solutions particularly for rural or remote areas. In addition to establishing five SHP plants, the organization also carries out feasibility studies for potential SHP projects with the aim to be invested in by private entities. A feasibility study for a Mavonde SHP project of 0.90 MW was carried out, approved and will begin construction once funds become available. Studies for SHP plants in Berua and Luaice have also been conducted, but no further progress has been announced.[6] SE4ALL, in collaboration with the African Development Bank, has expressed interest in aiding the investment in the creation of green mini-grids to be located in remote areas of Mozambique, which includes power from SHP. An in-depth assessment was made in 2017 that identified hundreds of potential SHP sites in eight provinces with a combined capacity of over 672 MW. These mini-grids along with others from solar power and biomass could bring electricity to 22 per cent of the total population, especially to the hardest to reach communities. To implement these projects, partnerships with international companies, banks and organizations would be necessary.[6]

RENEWABLE ENERGY POLICY

Mozambique is a country rich in natural resources with vast potential for renewable energy including 23,000 MW of solar power, 19,000 MW in hydropower, 4,500 MW of wind power and 2,000 MW of biomass. Harnessing these potentials would not only provide enough energy for the domestic population, but would produce a surplus that could be exported to surrounding countries.[14] Recent national plans routinely mention the development of renewable energy as a priority. The Five Year Plan 2015–2019 discussed the use of renewable energy to obtain other social development goals, such as increasing the electrification rate to 33 per cent by 2019 by increasing hydropower and solar power in rural areas and using solar power to electrify schools and health centres.[6] The actual national electrification rate in 2019 was slightly more than 29 per cent, indicating that this goal was missed by 4 percentage points.[8] The Energy Strategy published in 2015 in conjunction with the World Bank put forth the goal for the national electrification rate to reach 50 per cent by 2023 and 100 per cent by 2030. As of 2020, the country was still 19 percentage points away from reaching the goal in the three following years.

Some of the legal framework for foreign investment and renewable energy is currently undergoing review. The applicable laws presently in place are the Investment Law (Law 3/1993 and Decree 43/2009), Electricity Law (Law 21/1997, Decree 8/2000 and Decree 42/2005), Energy Policy (Resolution 5/1998 and Resolution 10/2009) and Private Public Partnership Law (Law 15/2011 and Decree 12/2012).[11] In 2021, the Government passed regulation framework for off-grid energy production to encourage private sector involvement in installing mini-grids in remote areas in hopes to accelerate electrification of these areas.[15] As of March 2022, the Government proposed, but not yet fully approved, an update of the Electricity Law that would also encourage private investments in the sector and make a more competitive environment.[16] As financial support to make the necessary enabling conditions for private sector investments, Sustainable Energy Fund for Africa (SEFA) approved a USD 740,000 grant in 2015 for technical assistance to do so.[16]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The National Water Policy (PNA, 1995) stipulates that hydropower installations are required to have a water use concession. In addition, the 1995 policy used two mechanisms for implementation, the Rural Water Transition Plan and the Implementation Manual for Rural Water Projects (MIPAR). In 2007, the PNA was revised and became the Water Policy (PA). The revision was aimed at meeting the United Nations Millennium Development Goals and included private investment in local water management and utilization. The Water Policy mentions the use of water resources for standalone and dam-connected hydropower purposes and states that small- and medium-scale hydropower facilities should be encouraged for off-grid electricity generation in remote areas, extension of the national electricity grid production and transmission capacity, as well as economic development in general.[11]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The challenges hindering the development of SHP in Mozambique include:

- Lack of a consolidated legal framework;
- Absence of a strategy defining governmental investment plans for hydropower plants;
- Limited information about the number and location of the existing plants as well as potential sites;
- Lack of local technologies;
- Underdeveloped market.

The factors encouraging SHP development in Mozambique include:

- Over 995 MW of SHP potential is untapped which offers considerable technical opportunities;
- Access to electricity in the country is still far from universal, especially in rural or remote areas. SHP development in remote areas can bring electricity to communities that have been without;
- Government plans favourable to SHP development.

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Réunion

Gaelle Gilboire, Energie Réunion

KEY FACTS

Population	868,846 (2022)[1]
Area	2,512 km^2 [2]
Topography	Réunion island is the result of volcanic activity, with mountain peaks in the interior and two distinct volcanoes: the Piton des Neiges (Snow Peak), which is now extinct, and the Piton de la Fournaise (Furnace Peak), which is younger and more active. The Piton des Neiges is also the highest point on the island at 3,072 metres above sea level.[2]
Climate	In general, the weather in Réunion is tropical and humid. The warm and humid season lasts from November to April, while the drier season occurs from May to October.[3] The summer, which lasts from December to March, has a mean temperature of 26 °C on the coast. Winter, from April to November, has an average temperature of 20 °C on the coast. At higher altitudes, temperatures drop significantly.[2]
Climate Change	Between 1968 and 2021, the average temperature in Réunion rose by 0.18 ° C per decade, or nearly 1 °C in total. By 2100, the average temperature rise is projected to reach 1–3 °C, which will impact the intensity and duration of heat waves and droughts. Between 1961 and 2021, the average rainfall decreased by 1.6 per cent per decade. By 2100, there should be one in five extra rainy days in the wet season and one less rainy day every five days in the dry season. The eastern part of the island will retain much more rainfall than the western part.[4]
Rain Pattern	Summer (January–March) is the wettest season with approximately 200 mm of rainfall per month falling along the coast and up to 1,000 mm in the inland areas. February is usually the wettest month. Annual rainfall exceeds 3,000 mm on the eastern coast and is below 1,000 on the western coast.[5]
Hydrology	A large number of rivers flow through Réunion, including the Rivière des Marsouins that runs abundantly all year round. Other notable rivers are the Sainte Suzanne, Grand-Bois, Salazie and Mafate Rivers.[2]

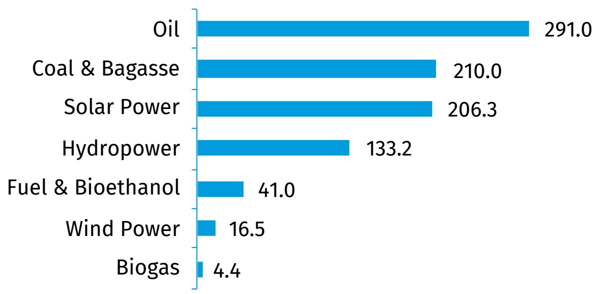
ELECTRICITY SECTOR OVERVIEW

Réunion Island is an overseas department and an administrative region of France. The French company Électricité de France (EDF) is the electricity provider on the island.

In 2020, total electricity generation on the island amounted to 2,978 GWh. Electricity was generated from thermal and renewable energy sources, with coal dominating the generation mix at almost 37 per cent of the total. Renewable energy sources accounted for a total of 31 per cent (Figure 1).[6]

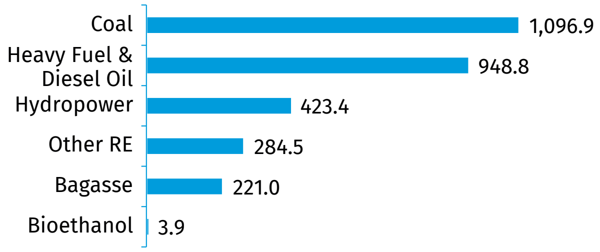
Total installed capacity as of December 2020 was 902.5 MW, of which oil-fired plants accounted for 32 per cent, coal- and bagasse-fired plants for more than 23 per cent, solar power plants for almost 23 per cent, hydropower for 15 per cent, fuel- and bioethanol-fired plants for over 4 per cent, wind power for 2 per cent and biogas for 0.5 per cent (Figure 2).[6] Until 2011, hydropower was the most utilized renewable energy source, as it was one of the first renewable energy sources developed on the island. However, since 2012, Réunion has invested in the development of other renewable energy technologies and now solar power exceeds hydropower in installed capacity.[6] In addition to the listed installed capacities, there is also 6 MW of storage capacity from two batteries.[6]

Figure 1. **Annual Electricity Generation by Source in Réunion in 2020 (GWh)**



Source: Energies Réunion[6]

Figure 2. **Installed Electricity Capacity by Source in Réunion in 2020 (MW)**



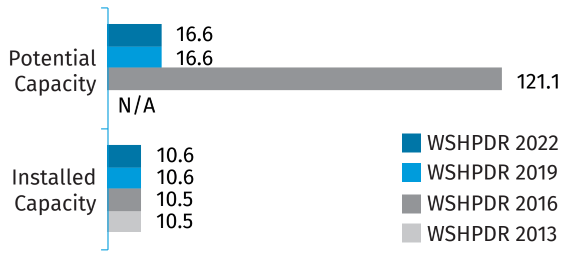
Source: Energies Réunion[6]

Although the cost of producing electricity is higher in Réunion Island due to its insularity, consumers benefit from tariff equalization, meaning that the prices are identical to those in Metropolitan France. Basic electricity tariffs vary according to the voltage and frequency of the electronic devices used as well as the time of the day when they are used. As of 2022, residential tariffs (inclusive of taxes) varied from 0.1371 EUR/kWh (0.14 USD/kWh) to 0.1706 EUR/kWh (0.18 USD/kWh).[7]

SMALL HYDROPOWER SECTOR OVERVIEW

Réunion, in accordance with French legislation, defines small hydropower (SHP) as hydropower plants up to 10 MW. The total SHP installed capacity in Réunion is 10.6 MW (Table 1).[6] The total untapped hydropower potential in the island is estimated at 121.1 MW, of which 59.1 MW is difficult to be developed, 50.5 MW can be developed under strict conditions and 11.5 has no limitations for development.[8] As far as SHP is concerned, the island has 6 MW of untapped potential, making it 17 MW in total.[7] Compared to *the World Small Hydropower Development Report (WSHPDR) 2017*, both installed and potential capacity remained unchanged (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Réunion (MW)**



Source: Energies Réunion,[6] Direction de l'eau,[8] *WSHPDR 2013*,[9] *WSHPDR 2016*,[10] *WSHPDR 2019*[11]

Hydropower on the island is produced at Rivière de l'Est (79.2 MW), Takamaka I (17.4 MW) and II (26.0 MW), Bras de la Plaine (4.6 MW), Langevin (3.6 MW), Bras des Lianes (2.2 MW), Ligne Paradis (0.2 MW) and RT4 (0.02 MW) plants, for a combined capacity of 133.2 MW.[6] Although a large share of the SHP potential has been tapped, there are still a number of potential sites where micro-hydropower projects can be developed (Tables 2 and 3).[14]

Table 1. **List of Existing Small Hydropower Plants in Réunion**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Ligne Paradis	Saint-Pierre	0.2	SAPHIR	2018
RT4	Saint-Paul, Ermitage	0.02	ALTERELEC	2013
Bras de la Plaine	Saint-Pierre	4.6	N/A	N/A
Langevin	Saint-Joseph	3.6	N/A	N/A
Bras des Lianes	Bras, Panon	2.2	N/A	N/A

Source: Energies Réunion[6]

Table 2. **List of Planned Small Hydropower Projects in Réunion**

Name	*Location*	*Capacity (MW)*
Sainte Etienne Riverr	Saint-Pierre	0.80
Restitution Rivière des Galets	Saint-Paul	0.50
Ligne Paradis	Saint-Pierre	0.42
Bras Cilaos – Maniron	Saint-Louis	0.39
Bras Cilaos – Bellevue	Saint-Louis	0.24
Bras cilaos – Larrey	Saint-Louis	0.15
ILO – RT8	Saint-Leu	0.10
Capteur de pression – A501C02	Saint-Pierre	0.07
PT13000 Interconnection ILO – BC	Les Avirons	0.07
Community reservoir "ville2"	Petite-Ile	0.06
ILO – RT3	Saint-Paul	0.04
ILO – RT6	Saint-Leu	0.04

Source: Regional Council of Réunion[12]

Table 3. **List of Potential Small Hydropower Projects in Réunion**

Name	*Location*	*Potential capacity (MW)*	*Type of site (new/refurbishment)*
Matarun	Cilaos	0.011	New; pipeline network
N/A	West coast	0.018	New; pipeline network

Source: Regional Council of Réunion[12]

RENEWABLE ENERGY POLICY

Act No. 2015-992, Article 1, of 17 August 2015 lays down the guidelines for energy policies and renewable energy for French overseas departments.[13] The law states that overseas departments should be energy-autonomous by 2030, with an intermediate goal of 50 per cent of renewable energy in the energy mix by 2020. In addition, incentive mechanisms are also in place to encourage the development of renewable energy, including tax exemptions, direct subsidies and feed-in tariffs (FITs) controlled by EDF.

In 2017, in the Multiannual Energy Programme (PPE) the Regional Council of Réunion Island and the Government of France defined the energy policy until 2023 for the island. The PPE set the development objectives for each renewable energy source for the period from 2018 to 2023 in order to achieve energy autonomy by 2030. The programme takes into account population and electricity consumption growth, with objectives focusing on demand-side management as well. In this document, the objective for hydropower is to add 39.5 MW of capacity between 2016 and 2023. However, the project of a new 39 MW turbine on which this objective was based will not be realised.[14]

In April 2022, an updated version of the PPE was adopted with new objectives set for 2023 and 2028. These include reducing electricity consumption by 263 GWh/year by 2023 and 438 GWh/year by 2028 as well as stopping using coal and heavy fuel oil for electricity generation. The two existing carbon-fired power plants will be converted to the use of biomass. The new objectives defined for hydropower are to add 6.6 MW of capacity by 2023 and another 1 MW by 2028, indicating a reduced focus on hydropower in the new edition of the PPE in favour of other renewable energy sources.[12]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers to SHP development include:

- Costly technology due to the insularity of the island and the related costs of transportation and taxes, which limits contractors' willingness to undertake financial risks and invest in Réunion;
- Climatic variations and destruction coupled with volcanic activity are other risk variables of the island that investors and contractors need to face;
- Réunion is classified by the United Nations Educational, Scientific and Cultural Organization (UNESCO) as a World Heritage Site, which has two main consequences: first, environmental impact assessments are stringent; and second, the price of land per square metre has experienced a significant increase, affecting initial investment expenditures;
- Ineffective coordination between local and overseas authorities prolongs the implementation process for project owners;
- Lack of local technical support;
- Lack of information and contradictory sources, slowing down the process of development.

On the other hand, the key enablers include:

- Availability of undeveloped SHP potential;
- Policy support of renewable energy;
- Availability of irrigation and water treatment infrastructure on which SHP plants could be installed.

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Rwanda

Davy Rutajoga, International Center on Small Hydro Power (ICSHP)

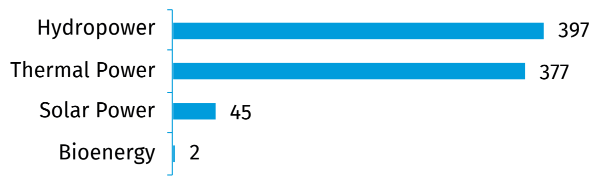
KEY FACTS

Population	12,955,736 (2021)[1]
Area	26,338 km^2 [2]
Topography	Rwanda is a landlocked country that lies 120 kilometres south of the equator in the Tropic of Capricorn. Rugged with steep hills and deep valleys, the altitude ranges from approximately 1,000 metres above sea level in the east to the 4,507 metre peak of Mount Karisimbi in the Virunga Volcano Range in the west of the country.[2,3]
Climate	Rwanda has a temperate tropical highland climate characteristic of high-altitude regions in the equatorial belt. Average annual temperatures range between 23 °C and 24 °C in lowlands and reach up to 17 °C in high altitude areas. Generally, temperatures vary little throughout the year.[4]
Climate Change	As a country that relies heavily on rain-fed agriculture, Rwanda is highly vulnerable to rising temperatures as well as the irregular rainfall patterns that have been projected to increase in the future. Increases in temperature of between 1.4 °C and 2.6 °C have been observed in the south-western and eastern regions of the country between 1971 and 2016. Precipitation also exhibited noticeable variations, with mean rainfall decreasing significantly in January, February, May and June and increasing significantly from September to December. Climate projections for the high-emissions scenario estimate an annual mean temperature increase of 1.1 °C between 2020 and 2039, 1.9 °C between 2040 and 2059, 2.9 °C between 2060 and 2079 and 3.9 °C between 2080 and 2099. Annual precipitation is also likely to increase, with a higher intensity of heavy rainfall. These variations in temperature and precipitation are projected to also impact water resources, which could in turn impact the energy sector.[5]
Rain Pattern	Rwanda experiences relatively abundant rainfall through its two rainy seasons: the long rainy season (March to May) and the short rainy season (September to November). The eastern plains enjoy an annual rainfall of between 700 mm and 1,100 mm, the central plateau of between 1,100 mm and 1,300 mm and the highlands of between 1,300 mm and 1,600 mm. The areas around the town of Bugarama and Lake Kivu benefit from an annual rainfall of between 1,200 mm and 1,500 mm. The mean annual precipitation in the country is 1,177.7 mm.[5]
Hydrology	Located in the Great Lakes region of Africa, Rwanda has 101 lakes split into two basins: the Nile basin to the east and the Congo basin to the west. The country's hydrological network covers approximately 8 per cent of the national territory, with 10 per cent of the water draining into the Congo basin. The largest lake in Rwanda is Lake Kivu, a methane-rich lake shared with the Democratic Republic of the Congo.[5]

ELECTRICITY SECTOR OVERVIEW

The electricity supply in Rwanda is made up of domestic generation and electricity imported from neighbouring countries and regional shared power plants.[6] The main sources of electricity in Rwanda are hydropower, thermal power (diesel and methane) and solar power accounting for approximately 48 per cent, 46 per cent and 6 per cent, respectively, of total production, which amounted to 821 GWh in 2019 (Figure 1). Renewable energy contributed a combined 54 per cent of the electricity generated.[7]

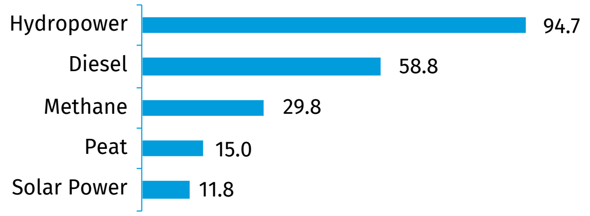
Figure 1. **Annual Electricity Generation by Source in Rwanda in 2019 (GWh)**



Source: IRENA[7]

The total installed capacity in 2020 was 210.1 MW, of which approximately 45 per cent came from hydropower, 49 per cent from thermal power (diesel, methane, peat) and 6 per cent from solar power (Figure 2). Thermal power is only used during peak hours due to the high operating costs associated, with hydropower taking over during off-peak hours as a cheaper option. Additionally, Rwanda imports electricity from the National Electricity Company of Congo (SNEL) and the Uganda Electricity Transmission Company (UETCL).[8]

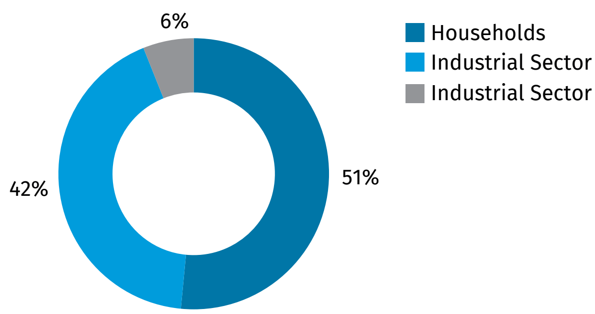
Figure 2. **Installed Electricity Capacity by Source in Rwanda in 2020 (MW)**



Source: REG[8]

In Rwanda, the dominant consumers of electricity are households, followed by industries and the public sector, with consumption rates of approximately 51 per cent, 42 per cent and 6 per cent, respectively (Figure 3). The per capita consumption rate is expected to increase to 3,080 kWh in 2050 from 50 kWh in 2019, with at least 60 per cent of the electricity to be generated from renewable energy sources under the Vision 2050 strategic plan for the transformation and modernization of the country.[5]

Figure 3. **Electricity Consumption by Sector in Rwanda (%)**



Source: World Bank[5]

Electricity in Rwanda is distributed by the Rwanda Energy Group (REG), a Government-owned corporation which oversees all energy development and investment plans in the country under the auspices of the Ministry of Infrastructure (MININFRA). Private entities can purchase, build and operate power plants in Rwanda, but the distribution is handled by the REG. As of 2021, the cumulative connectivity rate was 67 per cent of Rwandan households, including approximately 49 per cent connected through the national grid and 19 per cent accessing through off-grid systems (primarily solar power). An electricity access target of 100 per cent of households by 2024 with 69 per cent connected through the grid and 31 per cent off-grid has been set by the Government.[9]

Electricity tariffs are established by the REG and are based on flat rates and smart meters that measure levels of electricity consumption. The electricity tariffs for the main groups of consumers are listed in Table 1.

Table 1. **Average Electricity Tariffs in Rwanda**

Type of consumer	*Type of rate*	*Average electricity tariff (USD/kWh)*
Residential	Smart meter	0.089–0.245
Commercial	Smart meter	0.157–0.201
Industrial	Flat rate	0.106–0.151
Industrial 2	Smart meter	0.094–0.134
Public sector	Smart meter	0.126

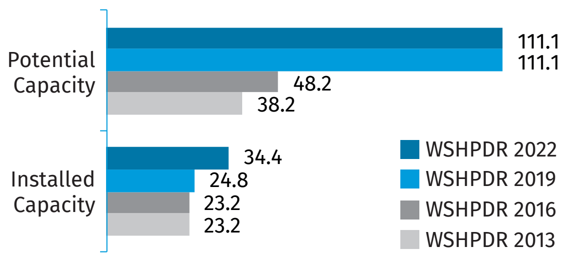
Source: REG[10]

Based on a study conducted by Israel Electric on the current and forecasted electricity demand in Rwanda for the years 2016–2040, an average of a 10 per cent annual demand growth rate has been estimated.[8] As part of the Vision 2050 plan, the development of electricity connectivity focuses on hydropower as the area with the most potential to meet the demand due to the abundance of water resources in the country and region.[5]

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) plants in Rwanda are defined as plants with an installed capacity of up to 5 MW. There were 29 SHP plants operating in Rwanda in 2020 out of 333 identified potential sites, with a total installed capacity of 34.4 MW and an available capacity of 18.66 MW.[8] The total theoretical SHP potential capacity in Rwanda is estimated to be 111.1 MW (based on planned projects and identified sites).[11] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the SHP installed capacity increased as a result of the commissioning of new plants, whereas the potential estimate remained unchanged (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Rwanda (MW)**



Source: REG,[8] *WSHPDR 2019*,[11] *WSHPDR 2016*,[12] *WSHPDR 2013*[13]

Note: Data for SHP up to 5 MW.

Table 2 lists 20 of the SHP plants operational in Rwanda.

Table 2. List of Selected Operational Small Hydropower Plants in Rwanda

Plant name	*Installed capacity*	*Available capacity*	*Operator*	*Launch year*
Mukungu	0.016	0.0096	IPP	2020
Kigasa	0.272	0.1000	IPP	2020
Nyirantaruko	1.840	1.2000	IPP	2020
Rubagabaga	0.450	0.2400	Rubagabaga Hydropower Ltd.	2019
Rukarara V Mushishito	2.300	1.2000	IPP	2019
Rwaza Muko	2.600	1.5600	Rwaza Hydropower Ltd.	2018
Gaseke	0.500	0.5238	Novel Energy	2017
Giciye II	4.000	1.6000	Rwanda Mountain Tea (RMT)	2016
Giciye I	4.000	1.6000	RMT	2013
Nyirabuhombohombo	0.500	0.1750	RGE Energy UK Ltd	2013
Rukarara II	2.200	1.1550	Prime Energy	2013
Mukungwa II	3.600	2.6280	Prime Energy	2013
Musarara	0.400	0.2205	Amahoro Energy	2013
Gashashi	0.280	0.1120	Prime Energy	2013
Nshili I	0.400	0.2400	Government of Rwanda	2012
Nyabahanga I	0.200	0.1100	Government of Rwanda	2012
Janja	0.200	0.1600	RGE Energy UK Ltd	2012
Mazimeru	0.500	0.2450	Carera-Ederer	2012
Cyimbili	0.300	0.1500	Adre Hydro&Energycotel	2011
Nkora	0.680	0.3400	Adre Hydro&Energycotel	2011
Nyamyotsi I	0.100	0.0600	Adre Hydro&Energycotel	2011

Source: REG[8]

In addition to the existing SHP plants, a further 10 SHP plants are planned in Rwanda, with some expected to start commercial operation between 2022 and 2024 (Table 3). The total nominal capacity of the planned SHP plants with an individual capacity of less than 5 MW is 32.8 MW and the nominal capacity of all planned plants up to 10 MW is 52.4 MW.[8]

Table 3. List of Selected Planned Small Hydropower Projects in Rwanda

Plant name	Nominal capacity (MW)	Planned launch year
Ngororero	2.7	2022
Nyundo	4.5	2022
Rwondo	2.3	2022
Base I	2.9	2024
Base II	2.9	2024

Source: REG[8]

MININFRA commissioned a study to identify potential hydropower sites, which was carried out in 2006-2007 by SHER ingénieur-conseil, a Belgian-based company funded by the Belgian Development Corporation. Through this study, a hydropower atlas highlighting the different potential areas for hydropower development was developed. Each identified site was classified based on its potential capacity, from pico-hydropower sites (up to 5 kW) to larger sites with more than 1 MW of capacity. Almost 50 per cent of the potential sites were found to be in the range of 5–100 kW. The theoretical hydropower potential capacity identified in the study totalled 82.6 MW, including 61.2 MW at already equipped or soon-to-be equipped sites.[8]

RENEWABLE ENERGY POLICY

The renewable energy sector is led by the Rwanda Energy Policy (REP), established as a guiding framework for the sector in 2015, following Law No. 21/2011 of 23 June 2011 governing electricity in Rwanda. Under the REP, the Rwanda Utilities Regulatory Authority (RURA) is mandated to regulate the supply of sufficient, reliable, affordable and sustainable energy to all customers. This supply follows the targets set for renewable energy by the Energy Sector Strategic Plan for 2018/19–2023/24, which guides the implementation of the REP.[14]

As part of the Vision 2050 plan, Rwanda is putting climate resilience and a low-carbon economy at the heart of its development. To this end, the share of renewable energy in the country's generation mix is targeted to reach at least 60 per cent by 2035.[5] SHP is an integral part of the country's effort towards achieving this goal, with sustainable small-scale generation installations in rural areas being a key component of the Green Growth and Climate Resilience Strategy of Rwanda. This strategy is highlighted in the country's Nationally Determined Contribution (NDC), with the increased use of hydropower (both large and small) representing the largest share of the identified greenhouse gas (GHG) mitigation potential.[15]

As part of the country's effort to promote SHP, a feed-in tariff (FIT) scheme was introduced between 2012 and 2015 by the Energy, Water and Sanitation Authority (EWSA) in close collaboration with the RURA. The scheme covered hydropower plants ranging in capacity from 50 kW up to 10 MW and located within 10 kilometres from the transmission network (Table 4). Although the policy expired after a duration of three years and has now been replaced by renewable energy tenders, this does not affect the projects that signed power purchase agreements (PPAs) under the scheme during that period.[16]

Table 4. **Small Hydropower Feed-in Tariffs in Rwanda**

Plant installed capacity (MW)	*Feed-in tariff (USD/kWh)*
0.05	0.166
0.10	0.161
0.15	0.152
0.20	0.143
0.25	0.135
0.50	0.129
0.75	0.123
1.00	0.118
2.00	0.095
3.00	0.087
4.00	0.079
5.00	0.072
6.00	0.071
7.00	0.070
8.00	0.069
9.00	0.068
10.00	0.067

Source: RURA[16]

Rwanda is a signatory to the United Nations Sustainable Energy for All Initiative (SE4ALL) and the Regional Strategy on Scaling up Access to Modern Energy Services adopted by the Council of Ministers of the East African Community. As such, the country adopted policies to create an environment that enables off-grid energy service provision including the development of small-scale renewable energy solutions.[16]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP plants are regulated by some of the same legislation as larger hydropower projects. The main legislation and regulation documents in Rwanda concerning hydropower are:

- The National Energy Plan (2015);
- Regulations No.001/ENERGY/RURA/2012 Of 09/02/2012 On Rwanda Renewable Energy Feed-In Tariff (2012);
- Guidelines No.02/GL/EL-EWS/RURA/2019 On Minimum Technical Requirements for Mini-Grids in Rwanda (2019).

Any energy generation project in Rwanda, including SHP plants, is required to receive a generation licence from the Rwanda Utility Regulatory Authority (RURA), with the fee depending on the planned capacity of the project (Table 5).

Table 5. **Electricity Generation Licence Fees in Rwanda**

Capacity	*Fee (USD)*
Less than 0.5 MW	5,000
0.5–1 MW	10,000
1–5 MW	15, 000

Source: RDB[17]

In addition to the generation licence fee, a licence application fee of USD 500 is to be paid.[17] As part of the application, the following documents have to be filed:

- Application letter addressed to the RURA Director General;
- Original receipt of the application fee payment;
- Domestic company registration certificate from the Rural Development Board (RDB);
- Business plan;
- Copy of the feasibility study of the project;
- Environmental Impact Assessment Certificate;
- Memorandum of understanding/Concession agreement between the Republic of Rwanda and the applicant;
- Power purchase agreement (not applicable to provisional licence);
- District authorization approving planned activities;
- Copies of applicant's financial statements audited by an independent auditor for the previous three years for the existing companies and the initial balance sheet for newly formed companies;
- Other relevant information detailed in the Electricity Licensing Regulations depending on the type of licence applied for.[17]

All licensing of power plants in Rwanda is acquired through the RDB, which oversees development projects in the country. The RDB is open to investors who wish to invest in SHP projects and has a directory of potential SHP sites and projects to accommodate investors. Most SHP projects are Government-funded through the RDB and the REG, with the remaining projects owned by companies and IPPs.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

With Rwanda depending on hydropower for most of its electricity generation, the effects of climate change are likely to significantly affect the energy sector in the country. Indeed, variations in rainfall patterns have already been observed and changes in mean temperature are predicted to occur, threatening water storage and supply.[5] In addition, hydropower is also vulnerable to the increased risk of damage to infrastructure, including roads, dams, turbines and supply lines, caused by floods. On the other hand, increased rainfall could also present an opportunity for SHP development as it would increase generation capacity at potential sites, which would bring the country closer to its goal of 60 per cent share of renewable sources in the generation mix by 2035.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Though SHP development presents an opportunity for Rwanda to reach its target energy goals, there are factors that hinder that development, such as:

- High costs associated with construction due to the relatively complex design of SHP plants, which require significant custom engineering. With few manufacturers to purchase from, the prices of building equipment are relatively high;
- Rwanda does not manufacture the necessary equipment for SHP plants and has to import them from outside of Africa, with import costs being relatively high due to the lack of a sea port in the country;
- The siltation as a result of the erosions caused by the hilly topography of the country and human activity (e.g., agriculture);
- The water levels drop by approximately 30 per cent during dry seasons, which affects generation by SHP plants;
- The mountainous topography of the country makes transmission and distribution relatively expensive.[18,19]

Enablers for further SHP development in Rwanda are:

- The availability of undeveloped potential SHP sites, which, due to their distributed nature, might be complimentary to micro-grids to provide 24/7 generation in combination with solar photovoltaic (PV) installations;
- Domestic production of electricity eliminates the need for foreign currency used for imports;
- Most potential SHP sites identified are suitable for development using run-of-river methods, which do not require large dams to impound water and, hence, are less environmentally challenging and more cost-effective;
- The Government's strategy to transition to a climate-resilient and low-carbon model of development specifically highlights the need for small-scale renewable energy production.

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Somalia (Federal Republic of)

Victor Odundo Owuor, One Earth Future Foundation

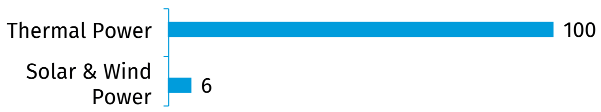
KEY FACTS

Population	15,442,905 (est. 2019)[1]
Area	627,340 km^2 [2]
Topography	Located in the Horn of Africa, Somalia boasts the longest coastline of any country in the continent. In the north, higher plateaus and mountains reach between 900 and 2,100 metres above sea level, gradually declining into a central plateau. In the south, the region transitions into lower coastal plains and fertile agricultural areas between the Jubba and Shabelle Rivers, before extending into low pastureland on the border with Kenya.[3]
Climate	Somalia has a semi-arid to arid climate, which is determined by its location in the Intertropical Convergence Zone.[4] Temperatures range between 20 °C to 40 °C in the south with cooler temperatures along the coast and reach as high as 45 °C in the northern coastal plains.[5]
Climate Change	Since 1991, the median annual temperature in Somalia has increased by 1–1.5 °C. Climate change projections predict that median annual temperatures will further increase by another 3.4–4.3 °C by the year 2100. Extreme weather phenomena are becoming more common and harder to predict. While a slight increase in rainfall of approximately 3 per cent is predicted by 2050, an increase in droughts and dust storms has also been observed. Additionally, the changing global and regional weather patterns have led to massive locust invasions in the Horn of Africa, costing Somalia approximately 20 per cent of national crop yields in 2020.[6,7]
Rain Pattern	The major wet season (*Gu*) lasts from April to June, followed by the *Haggai* season, which brings relatively cool temperatures with drier conditions on the inland plateau and light showers along the coast.[8] The *Deyr* rains occur from October through November, which lead into the longer dry *Jilaal* season spanning from December through March. Precipitation levels range from 700–800 mm/year in the Jubba and Shabelle regions to less than 100 mm/year along the northern coast.[4]
Hydrology	The majority of the country's water resources are dominated by surface water obtained from the Jubba and Shabelle Rivers, with 90 per cent of flows originating in the Ethiopian Highlands. Total internal water resources, including both surface and ground water, average 6 km^3/yr.[3]

ELECTRICITY SECTOR OVERVIEW

As of 2020, the installed electricity capacity of Somalia was estimated at 106 MW, down from an estimated historical capacity of 175–180 MW prior to the outbreak of the civil war in the early 1990s. The majority of the country's electricity is supplied by fossil fuel-based thermal generators (100.0–103.4 MW), with some renewable energy generated through solar and wind power (2.6–6.0 MW) (Figure 1).[3,9,10] Within the energy sector as a whole, as much as 80 to 90 per cent of energy originates from biomass sources, with the greatest share represented by charcoal. Fossil fuel usage accounts for 10 per cent of the energy mix, of which diesel-powered generators represent approximately 2 per cent.[9,10]

Figure 1. **Installed Electricity Capacity by Source in Somalia in 2020 (MW)**



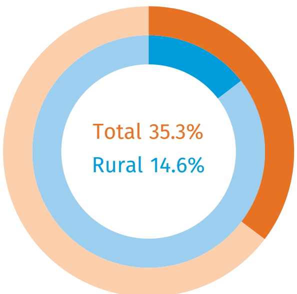
Source: AfDB,[3] USAID[9]

The decades' long civil war has undermined and destroyed much of the energy sector of Somalia. The combination of the protracted conflict and subsequent statelessness has significantly reduced the country's electrical generation capacity, namely through the destruction of electrical grids and by allowing infrastructure to fall into disrepair. Perhaps just as damaging was the effect that the war had on reducing international investment, the availability of a skilled workforce and Government regulatory oversight. In recent years, an added element of concern is the security risk that Al Shabaab and other armed militia groups pose to any large-scale infrastructure projects due to the potential for inflicting significant damage to the country's economic system.[11]

Precise and reliable data relating to installed capacity and electricity generation is difficult to obtain due to the fragmented nature of the energy sector and the sparse availability of data. The World Bank reported that 29.9 per cent of the population has access to electricity in 2016, which translated into an estimated 270,000–679,073 individual connections to households and businesses, while the most recent World Bank estimate indicates a 35.3 per cent electricity access rate in 2018 (Figure 2).[11,12] Other recent estimates put electricity access at as low as 16 per cent of the total population.[9] In terms of overall electricity consumption, estimates indicate that Somalis rank in the bottom 1 per cent of the world average at 28.7 kWh per capita and that some 2.4 million households do not have electrical power.[11]

These numbers do not reflect the vast disparity that exists between rural and urban populations' access to electricity. Electrification in rural areas is limited or non-existent due to the lack of infrastructure and connections to a larger electrical grid structure.[11] However, it should be noted that rural electricity access has shown gradual improvement with the added accessibility and convenience of solar photovoltaics (PV) technology, which has allowed some households and businesses to access electricity on a smaller, individual scale. Urban electrification varies by city and region, depending on the level of infrastructure and the generating capacity of privately owned electrical companies.[3] For example, estimates of electricity access in Mogadishu and Somaliland have reached as high as 60 to 70 per cent, whereas smaller cities, such as Merka, only have 23 per cent access.[13] The latest World bank estimates suggest a 60.5 per cent electricity access in urban areas, but only 14.6 per cent access in rural areas.[12]

Figure 2. **Electrification Rate in Somalia in 2018 (%)**



Source: World Bank[12]

As a result of the weakened state of the Somalian public energy sector, the private sector has taken a primary role in sourcing and providing electricity. Rather than through large, centralized systems of power generation, the majority of electricity in Somalia is generated by small independent providers operating through local or regional companies.[14] Without the Government oversight, these independent power companies have improvised their own local systems of electricity distribution, but lack a coherent interconnected grid between generators that could promote more efficient and cost-effective economies of scale.[11] In addition to these independent networks, there is also a smaller subset of semi-public utility companies that provide electricity to large urban areas, but they operate on dated grid systems and are only present in selected cities, including Hargeisa, Qardo, Berbera and Bosaso.[3]

While the flexible and adaptive nature of the private sector energy companies has its advantages, including access to private funding sources in the Somali diaspora and fast mobilization, they also have distinct weaknesses. The radial system of individual electrical networks is characterized by medium- to low-tension power supplies, which are further diminished by transmission losses of up to 50 per cent of starting power levels. Compared to other African countries or even other fragile and conflict-affected countries, this is four and two times higher than the average rate of losses, respectively.[3] This means that, on average, voltage rates are typically 220–400 V, but are often as low as 150–220 V. As a result, most households with access only use electricity for lighting purposes or other low current appliances.

The national and regional Governments are responsible for overseeing and implementing the energy sector policy. In 2010, the Ministry of Mining, Energy and Water Resources of Somaliland passed an Energy Policy that initiated a regulatory framework for the region. In conjunction with the Energy Policy, Somaliland has made multiple attempts to pass an Electrical Energy Act, which would establish a formal legal framework overseeing tariff rates, administration and skilled training initiatives; however, the Act has not been adopted as of 2021.[15] Overall, no legislation has been passed at the federal level that specifically addresses the electricity industry. However, in 2016 the Government partnered with the African Development Bank Group to complete an Energy Sector Needs Assessment, which laid out multiple strategies aimed towards expanding the electrical capacity of Somalia. One such strategy calls for increasing the supply of electricity to regional capitals through hybrid mini-grids, implying close to 200 MW of additional generating capacity over a 10-year period.[3] To date, the Government does not have the necessary staff or budget to initiate such projects and requires international donor support to accomplish its large-scale energy infrastructure goals.

This lack of regulation and oversight extends into the affordability of electricity as well. With average rates between 0.80 and 1.20 USD/kWh (Table 1), the electricity tariffs in Somalia rank among the highest in the world, especially when considering that the GDP per capita in 2017 was USD 434.21.[3,12] Most power companies do not have a formal metering system and instead charge by the number of light bulbs or the number of appliances powered within a household or business. Some independent providers have even utilized tiered rates, meaning that some public and private institutions like mosques or government facilities pay a lower rate as compared to other consumers or nothing at all.

Table 1. **Electricity Tariffs in Somalia**

Tariff type	*Price (USD/kWh)*
Nationwide average	0.80–1.20
Single-phase supply	0.60–1.20
Three-phase supply	0.65–0.80

Source: AfDB,[3] REEEP[13]

Regional variation in price is largely dependent upon the energy provider, the level of available infrastructure and the consumer's proximity to urban centres or the primary electricity generation source. In order to supplement its energy needs and to offset high tariffs, Somalia has tapped into power surpluses in neighbouring countries. In 2014, the Federal Government entered into a shared understanding with Kenya and Ethiopia to build a hydropower plant on their shared border on the Dawa River and has worked with Ethiopia to connect to its grid system in areas along the Somaliland border as well as in Puntland.[3] In the long term, there has also been discussion around utilizing the Eastern African Power Pool (EAPP) as a potential source of electric power, but the current load and lack of interconnection in Somalia suggest limited benefits for the required cost.[11]

SMALL HYDROPOWER SECTOR OVERVIEW

Somalia has no official definition for small hydropower (SHP). This chapter adopts the working definition of hydropower plants with an installed capacity of up to 10 MW. Currently there are no operational hydropower plants in the country; however, there is some potential to rehabilitate plants that were in place prior to the civil war. The current state of SHP does not reflect the historical development and use of hydropower in Somalia. Though it has fallen into disrepair, the Fanoole hydropower dam was completed in 1982 in partnership with China. The plant was designed to generate electricity for local communities in Jilil and Marere and to support an agricultural programme focused on sugar cane and rice irrigation.[16] In their 2016 Intended Nationally Determined Contributions (INDC) report, the Somali Federal Government announced plans to rehabilitate the dam's hydropower infrastructure for an estimated USD 28 million.[16] If completed, the refurbished plant would restore 4.6 MW of power as well as re-establish two standby generators with a capacity of 1,600 kW. This dam has the potential to reinvigorate the agricultural sector in the Middle and Lower Jubba Valley, but the project includes extensive repairs and rechannelling the path of the river which was diverted during the 1998 El Niño rainy season. The SHP potential of Somalia is unknown and is based only on known planned projects. Somalia remains a very challenged jurisdiction and no changes have occurred in its SHP sector since the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2019/2022 in Somalia (MW)**

Source: AfDB,[3] REEEP,[13] *WSHPDR 2019*[17]

Note: Somalia was not covered in *WSHPDR 2013* and *WSHPDR 2016*.

Relative to the abundance of hydropower generation in Ethiopia, Somalia has a much more limited capacity. The country has an estimated economic potential capacity of 100–120 MW of total hydropower, which is concentrated along the Shabelle and Juba Rivers in the south.[3,11] Historically, there were also plans to construct the Bardheere plant upstream of the Fanoole plant with a capacity of 493 MW, but the civil war effectively halted the project.[16] This reflects many of the challenges faced by Somalia in initiating SHP projects, namely the lack of financing from the Government and international donors, the current unpredictable weather patterns affecting Eastern Africa, concentration of already scarce resources to combat the COVID-19 pandemic and the high degree of terrorist activity conducted by Al Shabaab in the region.

RENEWABLE ENERGY POLICY

As mentioned, charcoal currently represents the most cost effective and accessible energy source in Somalia. However, the proliferation of charcoal consumption and its export to international markets in the Middle East has resulted in widespread deforestation, environmental degradation and negative health outcomes. The rising cost of charcoal (which sits at approximately 50 per cent of household incomes) and the vast potential for solar and wind power generation have driven the Federal and regional Governments to integrate renewable energy into their development plans and policies (Table 2).[3]

Table 2. **Renewable Energy Potentials in Somalia**

Type	*Potential*	*Location/Region*
Solar power	200 kW/km²	Coastal south-central Somalia
Wind power	30–45 GWh/km²	Puntland and Somaliland
Hydropower	100–120 MW	Juba and Shabelle River region

Source: Federal Government of Somalia,[10] REEEP[13]

Given the lack of any regulatory frameworks, renewable energy has been integrated into the larger discussion and the legislative push towards formal energy policy in Somalia. The different regional Governments have committed to a number of energy and renewable energy policy objectives (Table 3).

Table 3. **Energy Policies in Somalia**

Source	*Year*	*Policy*	*Objective*
Federal Government of Somalia	2014	2014–2015 Economic Recovery Plan	Incorporated provisions for renewable energy integration
	2016	2017–2019 National Development Plan	Sustainable Energy Investment Policy and Energy Strategy provision
Somaliland Ministry of Energy and Mining	2010	Somaliland Energy Policy	Promotion of renewable energy technologies and reduction of taxes and duties on importing renewable equipment;
			Increased budget allocation to ministries overseeing renewable energy activities;
			Infrastructure resources (i.e., transportation and communications) to help administrators implement and monitor renewable energy–related activities;
			To develop and sustain efficient use of renewable energy resources as part of the energy mix, in ways that increase affordable access in urban and rural areas.
Puntland	2013	2014–2016 Puntland Government Plan	Identified renewable energy as one of four key priorities for the economy;
			Set a target of a 20 per cent increase in solar and wind power generation and usage over a five-year period.

Source: Federal Government of Somalia,[10] One Earth Future,[11] REEEP,[13] Watanabe & D'Aoust[14]

COST OF SMALL HYDROPOWER DEVELOPMENT

There is very little data on the cost of potential SHP projects in Somalia now or in the future. However, a partial estimate of the costs of the refurbishment of the Fanoole plant is provided in Table 4.

Table 4. **Cost of the Refurbishment of the Fanoole Hydropower Plant**

Project component	*Cost (USD million)*
Initial cost of construction (1977–1982)	50.0
Refurbishment of dam and electrical facilities	17.0
Rehabilitation of canals and river channel	2.0
Rebuilding of offices, residential buildings and connected agricultural facilities	5.5
Contingency and administrative costs	3.7
Total (refurbishment)	**28.2**

Source: Federal Government of Somalia[16]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

As there is no current or projected SHP development in Somalia, it is difficult to gauge the possible impacts of climate change on its trajectory. While some increase in rainfall is expected over the next 30 years, precipitation and, thus, runoff are also likely to become less predictable and experience greater variation. However, the main aspect of climate change that is adversely affecting the prospects of SHP development in Somalia are the climate change impacts on the local population, including:

- Drought and land degradation undermining agricultural and pastoral livelihoods;
- Extreme weather displacing populations from affected regions;
- Increased confrontation between communities over dwindling resources.

These factors have led to continued social, political and economic instability in Somalia and have effectively made any kind of large-scale construction impossible in many parts of the country, particularly in the Shebelle and Juba River basins where much of the country's SHP potential is located.[7]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key challenges that Somalia faces in developing SHP are as follows:

- Security concerns surrounding regional terrorist groups, such as Al Shabaab, and the potential for SHP infrastructure and energy grids to be targeted or attacked;
- Limited regulation and oversight of the electricity sector;
- Lack of field studies for SHP potential;
- Low domestic resource mobilization coupled with on-going efforts to combat the COVID-19 pandemic have deepened fiscal pressures;
- Limited Government capacity to administer and regulate the energy sector;
- Lack of a skilled workforce to design, build and maintain SHP and renewable energy infrastructure due to the protracted conflict;
- Absence of an interconnected grid system with high enough capacity to support transmission and usage of electricity for both urban and rural populations;
- Aging equipment and poor infrastructure in thermal generation, which contributes to up to 50 per cent of electricity loss;
- Scarcity of private sector financing for renewable energy projects and materials;
- Limited interconnection with regional power pools, particularly those in Ethiopia and Kenya;
- Low donor support for large-scale government projects, including those for rehabilitating SHP plants in poor condition and initiating a mini-grid system in key urban areas.

The main prospect for SHP development in Somalia remains the refurbishment of the Fanoole plant on the Juba River. The plant's infrastructure is still largely intact and preliminary plans for proposed works were drawn up in 2015. Refurbishment of the plant, if completed, is expected to have a major positive impact on local agricultural productivity.

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South Sudan

International Center on Small Hydro Power

KEY FACTS

Population	11,381,377 (2020)[1]
Area	633,907 km^2 [2]
Topography	South Sudan mostly consists of mountains, plains and plateaus. The central region is relatively flat and has multiple swamps, while the peripheral areas are higher in elevation. Near the southern border with Uganda lies the Imatong Mountain Range, home to the country's highest peak, Mount Kinyeti, which culminates at 3,187 metres.[3]
Climate	South Sudan has a tropical climate. Temperatures are generally high at an average of 25 °C, often exceeding 35 °C in the dry season (January-April). In the centrally-located capital city of Juba, temperatures reach an average high of 34.5 °C and an average low of 21.6 °C.[4]
Climate Change	South Sudan is affected by global warming. In recent years, the frequency and intensity of extreme climatic events has increased, including floods and droughts. Heatwaves and droughts have also been reported. Since the mid-1970s, the country has experienced a 10–20 per cent decrease in long rains. The agricultural areas, usually receiving the most rainfall in South Sudan, have experienced an 18 per cent decrease in precipitation. This country-wide decrease in precipitation is projected to reach a peak decrease, between 2010 and 2039, of 150 mm between June and September. Average temperatures in the country are projected to increase by 0.6-1.7 °C by 2030 and by 1.1-3.1 °C by 2060.[5]
Rain Pattern	South Sudan experiences a rainy season from April to November, although this can vary from region to region. The lowland areas of Jonglei, Bahr El Ghazal, Eastern Equatoria and the Upper Nile receive annual precipitations between 700 mm and 1,300 mm. However, the southern tip of Eastern Equatoria receives less rainfall (approximately 200 mm). The southern upland areas receive the most rain and the northern areas the least. Western Equatoria receives between 1,200 mm and 2,200 mm of precipitation annually.[4]
Hydrology	The hydrological landscape of South Sudan is dominated by the Nile River system, which runs from south to north and is joined by its tributaries: the Bahr Al-Arab, Sobat and Bahr El Ghazal. A large swampy area, the Sudd wetland, occupies the centre of the country and is one of the largest freshwater ecosystems in the world. It incorporates an area of about 57,000 km^2.[5]

ELECTRICITY SECTOR OVERVIEW

Due to the status of South Sudan as the newest nation in Africa, which it became after gaining independence in 2011, the electricity sector in the country is still undeveloped. The transmission system has not been updated nor has the country's renewable energy potential been exploited. The main source of electricity in South Sudan is thermal power, which accounted for 580 GWh, or 99.8 per cent, of the total electricity generation of 581 GWh in 2019 (Figure 1). Solar power accounted for 0.2 per cent, or 1 GWh, of the total electricity generated that year.[6]

Due to the country's history of civil war and its relatively recent cessation from Sudan, little electrical infrastructure has been built. There is no extensive electricity grid in the country and most businesses and individuals rely on their own diesel-powered generators for electricity. The total installed electricity capacity in South Sudan in 2020 was 175 MW, with thermal power and solar power accounting for approximately 99.4 per cent and 0.6 per cent, respectively (Figure 2).

Figure 1. **Annual Electricity Generation by Sources in South Sudan in 2019 (GWh)**

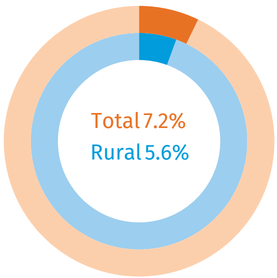
Source: IRENA[6]

Figure 2. **Installed Electricity Capacity by Source in South Sudan in 2020 (MW)**

Source: IRENA[6]

Due to the lack of an extensive electricity grid and overall electricity infrastructure, South Sudan has the lowest rate of electrification in the world. The total electrification rate in the country was 7 in 2020, with less than 6 per cent rate of access in rural areas (Figure 3).[7,8]

Figure 3. **Electrification Rate in South Sudan in 2020 (%)**



Source: World Bank[7,8]

South Sudan is endowed with considerable natural resources, including crude oil and natural gas. Crude oil exports form the backbone of the country's economy, with Sudan being one of the main importers.

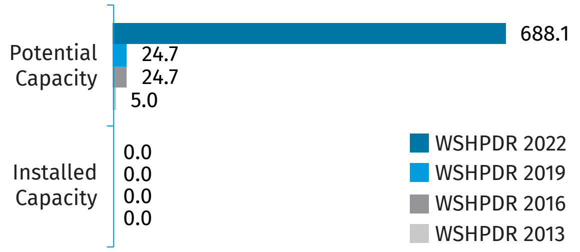
The South Sudan Electricity Corporation (SSEC) is the only electricity utility in the country and is mandated with the production, distribution and supply of electricity. It is overseen by the Ministry of Electricity, Dams, Irrigation and Water Resources. The SSEC has also undertaken the task of overseeing the rehabilitation of the few power plants damaged during the civil war through partnerships with other countries, particularly China. This partnership with China has also resulted in the construction of 33 kV transmission lines that are to supply 20,000 customers with electricity, as well as the production of 13,450 prestressed concrete poles for power plants that are being built for the purpose of creating an extensive national grid and establishing interconnections with neighbouring countries. A loan of USD 14.6 million from the African Development Bank has been approved for the grid project, supplementing the initial loan of USD 26 million issued in 2013. The new loan was approved in 2017 and construction began in 2018.[9]

Electricity tariffs in South Sudan were set in 2014 and reviewed in 2017 to reach an average of 0.43 USD/kWh.[10]

SMALL HYDROPOWER SECTOR OVERVIEW

South Sudan does not have an official definition of small hydropower (SHP). Despite abundant natural resources and considerable hydropower potential, there are no SHP plants in the country. There is an estimated SHP potential of 688.1 MW that is yet to be exploited.[11] This is a 2,686 per cent increase from the estimated SHP potential in the *World Small Hydropower Development Report (WSHPDR) 2019* and is based on a more recent study of SHP potential in Sub-Saharan Africa (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in South Sudan (MW)**



Sources: Korkovelos et al.,[11] *WSHPDR 2013*,[12] *WSHPDR 2016*,[13] *WSHPDR 2019*[14]

RENEWABLE ENERGY POLICY

South Sudan does not have a renewable energy policy framework. Despite considerable renewable energy potential, the developed renewable energy is in the form of individual rooftop solar panels. Plans have been discussed and technical evaluations have been completed for a 20 MW solar farm financed by the African Import-Export Bank. There are also plans to build hydropower plants. The SSEC is looking for investors to build a 120 MW hydropower plant near the capital city of Juba and a 1,080 MW Grand Fula Dam near the border with Uganda, with construction expected to start within five years of securing funding. The hydropower projects proposed by the Government are all large-scale.[9]

BARRIERS AND ENABLERS TO SMALL HYDROPOWER DEVELOPMENT

The development of new SHP projects is hampered mainly by:

- A lack of feasibility studies on potential sites due to civil war;
- Focus on developing the national grid and exploiting the natural crude oil and gas reserves;
- Lack of attention to SHP projects in favour of larger hydropower projects;
- Lack of private investors due to the volatile economy and concerns over renewed armed conflicts;
- Lack of a renewable energy policy framework.

Enablers for SHP development in South Sudan include:

- Considerable identified SHP potential;
- The particularly low rate of access to electricity might influence the Government of South Sudan to provide solutions to isolated peoples in the form of SHP.

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Tanzania

Wakati Ramadhani Mwaruka, Small Hydropower Centre Tanzania, University of Dar es Salaam

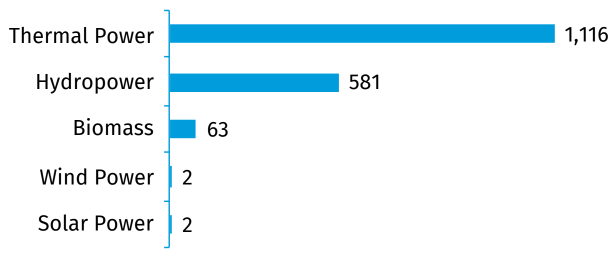
KEY FACTS

Population	57,637,628 (est. 2020)[1]
Area	948,740km^2 [1]
Topography	The landscape of mainland Tanzania is generally flat and dominated by plains along the coast, transitioning to a central plateau and highlands in the north and south. The highest peak in the country is Mount Kilimanjaro at 5,895 metres, located in the north-east.[2]
Climate	The climate in Tanzania is tropical. In coastal areas climate is hot and humid, while in the north-western highlands it is cool and temperate. There are two rainy seasons: the short rains are generally from October to December, while the long rains last from March to June. In the central plateau, climate tends to be dry and arid throughout the year.[3]
Climate Change	In 2020, annual precipitation in the country reached 1,227 mm, 198 mm above the long-term (1981–2010) average, making 2020 the fifth wettest year on record since 1970. Projections of climate change predict an increase in mean seasonal temperatures of over 2.0 °C by 2050 and of up to 3.8 °C by 2100 in various parts of the country, with increases most pronounced between June and August.[3,4]
Rain Pattern	Mean annual rainfall in Tanzania ranges from 500 mm to more than 2,500 mm. The average duration of the dry season is between five and six months. Rainfall patterns have recently become much more unpredictable, with some regions receiving extremely low or extremely high annual rainfall.[5]
Hydrology	Tanzania is surrounded by water bodies covering an area of 59,050 km^2, or approximately 6 per cent of the total area of the country. Major water bodies include the Indian Ocean on the east coast, Lake Victoria in the north-west, Lake Tanganyika in the west and Lake Nyasa in the south. River resources in Tanzania are divided into nine water basins: the Pangani River Basin, Rufiji River Basin, Lake Victoria, Wami-Ruvu, Lake Nyasa, Lake Rukwa, Lake Tanganyika, Internal Drainage and the Ruvuma and Southern River Basins. Major rivers in Tanzania include the Rufiji, Great Ruaha, Kagera, Ruvuma, Wami, Malagarasi, Mara and Pangani.[2,6]

ELECTRICITY SECTOR OVERVIEW

The total installed capacity of Tanzania as of 2022 amounted to 1,764 MW, with thermal plants (primarily gas-fired) providing 1,116 MW (63 per cent) of the total, hydropower providing 581 MW (33 per cent), biomass providing 63 MW (4 per cent) and other energy sources, including wind and solar power, providing 4 MW (less than 1 per cent) (Figure 1).[7]

Figure 1. **Installed Electricity Capacity by Source in Tanzania in 2022 (MW)**

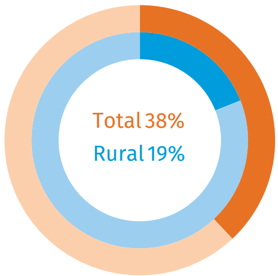


Source: USAID[7]

The country's electricity subsector is dominated by the grid network owned by the state-owned company Tanzania Electric Supply Company Limited (TANESCO). However, the 2009 Electricity Act opened the sector for private companies and ended the 40-year monopoly held by TANESCO. The penetration of independent power producers (IPPs) so far has been limited but steadily increasing.

Domestic generation of electricity in Tanzania during the 2019/2020 fiscal year reached 7,594.3 GWh, while imports amounted to 111.3 GWh. TANESCO accounted for 81 per cent of the domestically-generated electricity, while IPPs accounted for the remaining 19 per cent.[8] According to the World Bank, access to electricity in 2019 was approximately 38 per cent nationwide and 19 per cent in rural areas (Figure 2).[9] Peak electricity demand in 2018 was 1,045.7 MW and is projected to reach approximately 4,020 MW by 2025.[10,11]

Figure 2. **Electrification Rate in Tanzania in 2019 (%)**



Source: World Bank[9]

Despite the abundance of small hydropower (SHP) resources in most parts of the remote areas of Tanzania, the rural areas of the country remain virtually unelectrified. For many years the country's rural electrification efforts were focused on grid extension, which has proved to be economically unsustainable and financially prohibitive. Decentralized renewable energy has been considered as an alternative to shift the country's focus from grid extension to rural electrification. The Rural Energy Act of 2005 established the Rural Energy Board, Rural Energy Fund and Rural Energy Agency, which are responsible for the promotion of improved access to modern energy in rural areas. Standardized Power Purchase Agreements (SPPA) and Standardized Power Purchase Tariffs (SPPT) have been established specifically for small power producers. Since the country's energy sector reform in 2005, there has been a considerable increase in electrification rates in urban and rural areas, which has been largely underpinned by the efforts of the Government in deploying renewable energy technologies, including hydropower. These efforts have resulted in nearly 70 per cent of rural villages achieving electricity access by the end of 2021.[12]

In December 2020, TANESCO entered into an agreement with six renewable energy producers to purchase 19.16 MW of generation capacity to be connected to the national grid in various parts of the country. The agreement includes 10 MW from the Kahama solar power project, 5 MW from the Kigoma solar power project, 1.7 MW from the Madope hydropower project, 1.2 MW from the Maguta hydropower project, 0.9 MW from the Luponde hydropower project and 0.36 MW from the Ijangala hydropower project, developed by Nishati Lutheran Investment.[13] Furthermore, development of the privately-owned 5.39 MW Kitewaka SHP project is underway, with construction to commence in 2022.[14]

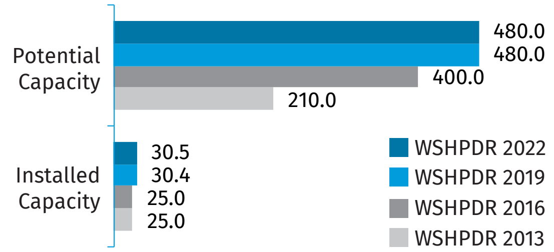
The biggest power infrastructure project in Tanzania in recent years is the 2,115 MW Nyerere hydropower plant, with construction ongoing as of 2021.[15] The project is expected to greatly boost electricity generation in the country upon completion, reducing both generation costs and end-user electricity tariffs.

Electricity tariffs for consumers in Tanzania are approved by the Energy and Water Utility Regulatory Authority (EWURA) and are divided into categories based on consumer type and electricity use. Service and energy charges were last reviewed in 2016, with the average tariff set at 250.62 TZS/kWh (0.11 USD/kWh).[16]

SMALL HYDROPOWER SECTOR OVERVIEW

Tanzania defines SHP plants as hydropower plants with an installed capacity below 10 MW. The installed SHP capacity of Tanzania is estimated at approximately 30.5 MW as of 2022, including isolated and off-grid SHP plants. The total estimated potential SHP capacity is 480 MW, indicating that approximately 6 per cent has been developed so far.[6,17,18,19] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed SHP capacity increased marginally by less than 1 per cent due to a new SHP plant commissioned in 2019, while potential SHP capacity remained the same, owing to lack of up-to-date studies of SHP potential (Figure 3).[6]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Tanzania (MW)**



Source: *WSHPDR 2019*,[6] Small Hydropower Centre Tanzania,[17] Michael,[18] Kassana et al.,[19] *WSHPDR 2013*,[20] *WSHPDR 2016*[21]

Most of the developed SHP projects in Tanzania are owned by private entities and are not connected to the national electricity grid. For many years, SHP development was promoted mainly by missionaries for provision of power to community facilities such as health centres, schools and vocational centres. Grid-connected SHP plants contribute just 15 MW of the total installed SHP capacity. Five SHP plants in the 300–8,000 kW range are owned by TANESCO, while faith-based groups operate more than 1,617 SHP plants, with a range of capacities from 15 kW to 800 kW and an aggregate capacity of 2 MW. A partial list of existing SHP plants in the country is displayed in Table 1, while several ongoing SHP projects are listed in Table 2.[17]

Table 1. **List of Selected Existing Small Hydropower Plants in Tanzania**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Tanapa-Arusha	Arusha	0.080	Arusha National Park	2019
Salala/Ludilu	Makete/Ludewa	0.068	Nishati Associate / Village Community	2017
Kiliflora	Arusha	0.280	Kiliflora Company LTD	2017
Tulila	Songea/Ruvuma	5.000	Benedictine Sisters of St. Agnes, Chipole	2016
Lilondo	Songea/Ruvuma	0.040	Village Community	2015

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Iyovi	Kilosa/Morogoro	0.950	Private	2015
Mbangamao	Mbinga/Ruvuma	1.000	Andoya Hydroelectric Power Company	2015
Matombo	Matombo/Morogoro	0.020	Village community	2013
Mawengi	Ludewa/Njombe	0.300	RC Njombe diocese and village community	2013
Mwenga	Mufindi/Iringa	4.000	Mufindi Tea Company	2010
Mbingu	Ifakara/Morogoro	0.850	Mbingu Sisters Convent	2009
Kinko	Lushoto/Tanga	0.010	Village community	2006
Mavanga	Ludewa/Njombe	0.150	RC mission/Mavanga Village community	2002
Matembwe	Njombe	0.150	RC mission/CEFA/Matembwe Village	1986
Ngaresero	Arusha	0.015	M.H Leach	1982
Lugarawa	Ludewa/Njombe	0.140	RC Mission	1979
Kitai	Songea/Ruvuma	0.045	Prisons Dept/Government	1976
Ikonda	Makete/Njombe	0.040	RC Mission	1975
Nyagao	Lindi	0.016	RC Mission	1974
Isoko	Tukuyu/Mbeya	0.016	Moravian Mission	1973

Source: Small Hydropower Centre Tanzania,[17] Michael,[18] Kassana et al.[19]

Table 2. **List of Selected Ongoing Small Hydropower Projects in Tanzania**

Name	*Location*	*Capacity (MW)*	*Developer*	*Development stage*
Sunda Falls SHPP	Tunduru	3.000	Tunduru DC & CAMS SKY AFRICA	Feasibility study completed
Lupali SHPP	Njombe	0.640	Benedictine Sisters – Imiliwaha	Under construction
Ijangala SHPP	Makete	0.360	Tandala Diaconical Centre/Nishati Lutheran Investment	Under construction
Makurukuru SHPP	Lumeme River	0.350	Andoya Hydro Electric Company Ltd	Feasibility study completed
Mbulu SHPP	Mbulu	0.070	Arusha Technical College	Under construction

Source: Small Hydropower Centre Tanzania[17]

A number of surveys have been carried out assessing SHP potential in Tanzania. At least four different studies have identified hundreds of potential SHP sites in different parts of the country, with estimates of total potential capacity ranging between 77.76 MW and 408.12 MW. Considering a probable degree of overlap between these studies, the total potential SHP capacity in the country is somewhere in the 300–500 MW range, with 480 MW considered a reasonable upper limit.[17,18,19,22]

The most recent comprehensive assessment of the SHP potential in Tanzania was carried out by the World Bank in 2017 through its Energy Sector Management Assistance Program (ESMAP), under close supervision of the Rural Energy Agency. Several prospective SHP sites identified by ESMAP are listed in Table 3.

Table 3. **List of Selected Potential Small Hydropower Sites in Tanzania**

Name	*River*	*Connection*	*Potential capacity (MW)*
Momba I	Momba	Sumbawanga Minigrid	5.860
Mbagala	Mbagala	Masasi Minigrid	3.530
Mfizi II	Mfizi	Mpanda Minigrid	3.040
Lwazi	Lwazi	Sumbawanga Minigrid	2.100
Kitandazi II	Mbinga	Mbinga Minigrid	0.330

Source: ESMAP[23]

RENEWABLE ENERGY POLICY

While there is no comprehensive renewable energy policy in Tanzania, the Government has issued policy statements and legislation that include provisions in support of renewable energy. These include the Rural Energy Act of 2005, which established the Rural Energy Agency and Rural Energy Fund, as well as the Electricity Act of 2008, which established procedures for the diversification of generation sources. The SPPA/T framework established by EWURA provides additional regulatory support for small producers and is reviewed annually to reflect operating costs. As of 2018, a renewable energy feed-in tariff (REFIT) policy draft was under review by EWURA.[24]

Small-scale power producers (0.1–10 MW) based on RES are regulated by EWURA under the small power projects (SPP) framework, which assigns technology-specific standardized power purchase tariffs (SPPT) based on a capacity range. SPPTs effective as of May 2019 are displayed in Table 4.

Table 4. **Standardized Power Purchase Tariffs for Small Power Producers in Tanzania in 2019**

Capacity (MW)	*Price (USD/kWh)*				
	SHP	*Wind power*	*Solar power*	*Biomass*	*Bagasse*
0.10–0.50	0.1065	0.1082	0.1054	0.1015	0.0971
0.51–1.00	0.0990	0.0995	0.0984	0.0934	0.0909
1.01– 5.00	0.0895	0.0942	0.0924	0.0864	0.0856
5.01–10.00	0.0783	0.0888	0.0834	0.7600	0.0755

Source: EWURA[25]

Additionally, EWURA applies separate regulations to very small power projects (VSPPs) up to 100 kW, which are able to set retail tariffs without EWURA's approval. To qualify for the VSPP status, a project must meet several thresholds including a return on equity of 18.5 per cent, a debt-to-equity ratio of 70:30 and a depreciation period of 20 years, among others. SHP up to 100 kW must have a capacity factor of no less than 55 per cent to qualify for the VSPP status.[25,26]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Tanzania has nine Basin Authorities, which in addition to other functions are responsible for issuing water permits to water users (including SHP developers and operators) as well as for annual fee collection from permit holders. The developer must submit project details to the relevant Basin Authority prior to the start of the project in order to receive the water use permit. After receiving the permit, the developer pays annual water use fees based on the volume of water used for power generation.

COST OF SMALL HYDROPOWER DEVELOPMENT

SHP projects in Tanzania are heavily reliant on imported technology and foreign expertise, driving up development costs. The 850 kW Ifumbo hydropower plant, constructed in 2008, carried a total project cost of USD 5.5 million, indicating a cost of USD 6,470 per installed kW. Funding for this project was largely provided by a Swiss donor.[27] The ongoing construction of the Kitewake SHP plant, with a total planned capacity of 5.39 MW, is expected to cost a total of USD 21 million, or 3,896 USD/kW. Meanwhile, two run-of-river cascades currently under construction in the Rift Valley and the Great Ruaha Basin, consisting of several plants and totalling 17 MW of planned capacity each, will cost USD 46 million and USD 65 million, with respective costs of 2,706 USD/kW and 3,824 USD/kW.[28] These numbers indicate a clear cost-saving trend as projects increase in scale.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Observed and projected changes in the hydrological regime in Tanzania both point to an increase in surface runoff and precipitation in the coming decades. Climate projections under the RCP8.5 scenario indicate an increase of as much as 27 per cent in annual precipitation by the mid-21st century. Surface runoff is expected to increase by anywhere from 13 per cent to 94 per cent during the same period across the country, with certain watersheds experiencing an increase of up to 160 per cent.[29] While gradual increases in runoff could be beneficial for the long-term sustainability of hydropower generation in the country, extreme locally concentrated runoff events and flooding could pose a threat to hydropower infrastructure in those areas.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Tanzania is endowed with abundant SHP potential but most of the surveyed sites have not yet been developed. The major challenges hampering SHP development in the country are summarized below:

- Low financial sustainability for project developers including NGOs and municipal authorities;
- Lack of local expertise and human resource development in the SHP sector, additionally hampered by a framework that tends to concentrate knowledge and talent in government ministries and cause a lack of qualified third-party personnel at the local level, particularly in rural areas;
- Lack of local technology and manufacturing capacity for SHP;
- Inability of rural customers to bear the financial burden of power infrastructure development;
- Lack of long-term planning with regard to rural electrification;
- Insufficient information about potential sites and other hydrological data, with existing inventories not exhaustive or up-to-date;
- Inadequate development incentives and awareness of the benefits of SHP;
- Lack of joint ventures in the form of public-private partnerships.

Enablers for SHP development in Tanzania include the following:

- Substantial existing untapped SHP potential across the country;
- Abundant water resources and stable prospects for water resource exploitation even in the face of climate change;
- Existing studies and surveys mapping hundreds of potential SHP sites;
- Substantial national experience with SHP development and generation;

- Government policy supportive of off-grid generation and small power plants as the primary means of rural electrification.

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Uganda

George Kimbowa, Wageningen University and Busitema University

KEY FACTS

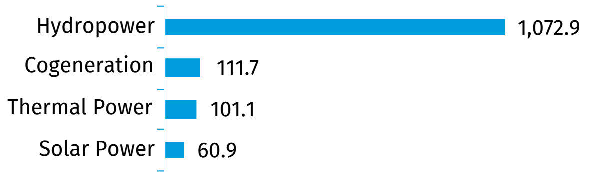
Population	44,269,594 (est. 2020)[1]
Area	241,551 km^2 [2]
Topography	The topography of Uganda mainly consists of a plateau with heights ranging from 800 metres to 2,000 metres. The country is bounded by several mountain ranges including the Rwenzori Mountains along the western border, with Margharita Peak on Mount Stanley, the third highest in Africa, rising to 5,109 metres, and Mount Elgon rising to 4,320 metres. The Western Rift Valley runs north to south through the western half of the country. The lowest point in Uganda is at 621 metres on the surface of Lake Albert.[3]
Climate	Uganda has a generally warm, tropical climate varying from a rainforest/monsoon climate in the south-east to a savannah climate in the north. The country's mean annual temperature is approximately 26 °C, with maximum temperatures between 18 °C and 31 °C and minimum temperatures between 15 °C and 23 °C. Temperatures are lower in the south-west and higher in the north and north-east, where the country experiences semi-arid conditions. Seasonally, temperatures are coolest between June and August and warmest from December to May.[4,5]
Climate Change	Climate change projections for Uganda vary according to different scenarios, but an increase by 1.5–2.0 °C is projected by the 2060s and by as much as 2.5 °C by the 2090s under RCP4.5, relative to the 2010s. Under RCP8.5, an increase of as much as 5.0 °C is projected by the 2090s.[6]
Rain Pattern	Uganda receives an annual rainfall ranging from 400 mm for the eastern Karamoja region to 2,800 mm for the Lake Victoria and Mountain Elgon regions, with an average of 1,180 mm.[6,7] The country experiences two rainy seasons, with heavy rains from March to May and lighter rains from October to December. The dry seasons are from December to February and from June to August.[4]
Hydrology	Most of Uganda belongs to the Nile drainage basin, except a small portion in the north-east of the country that drains into the Lake Turkana and Lotikipi basins in Kenya. Approximately 16 per cent of the total land area of the country is covered by wetlands and open water, with the south-east dominated by Lake Victoria, the source of the White Nile River, which extends into neighbouring Kenya and Tanzania.[7] The White Nile flows north, connecting Lake Victoria, Lake Kyoga in Central Uganda and Lake Albert on the border with the Democratic Republic of the Congo.[2] The Albert Nile flows northwards out of Lake Albert into South Sudan. Other major waterbodies in Uganda include Lake George and Lake Edward, located along with Lake Albert in the western arm of the East African Rift Valley. Most of the lakes in Uganda are transboundary, with the exception of Lake Kyoga and Lake George.[8]

ELECTRICITY SECTOR OVERVIEW

Uganda is endowed with a variety of natural energy resources, including both renewable and non-renewable energy sources such as hydropower, biomass, solar power, geothermal power, peat and fossil fuels. Biomass is the predominant energy type in Uganda, accounting for 94 per cent of the country's total energy consumption. In terms of power generation, the renewable energy power generation potential of Uganda is estimated at 5,300 MW. This includes over 2,000 MW of hydropower potential, 1,650 MW of biomass cogeneration potential and 450 MW of geothermal power potential. Uganda additionally has considerable peat reserves estimated at 250 million tons and an average daily irradiation of 5.1 kWh/m^2.[9]

The total installed capacity in Uganda was 1,346.6 MW in 2021, including hydropower with 1,072.9 MW (approximately 80 per cent of the total), bagasse-fired cogeneration plants with 111.7 MW (8 per cent), thermal power with 101.1 MW (8 per cent), and grid-connected solar power with 60.9 MW (5 per cent) (Figure 1).[10] Over the last 20 years the installed capacity of Uganda has more than tripled, amounting to just 400 MW in 2000. By mid-2022, total installed capacity in the country was expected to increase by another 600 MW with the upcoming commissioning of the Karuma hydropower plant.[11,12]

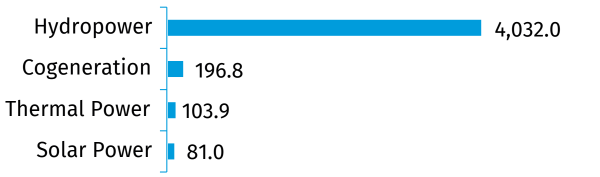
Figure 1. **Installed Electricity Capacity by Source in Uganda in 2021 (MW)**



Source: ERA[10]

In 2019, total generated electricity amounted to 4,413.7 GWh, with hydropower accounting for 4,032.0 GWh (91 per cent of the total), cogeneration for 196.8 GWh (4 per cent), thermal power for 103.9 GWh (approximately 2 per cent) and solar power for 81.0 GWh (less than 2 per cent) (Figure 2). While overall electricity generation has been rising steadily since 2015, the contribution of thermal power has been on the decline since 2017, underlining the ongoing shift towards renewable energy sources, particularly, the expansion of hydropower and solar power[13]

Figure 2. **Annual Electricity Generation by Source in Uganda in 2019 (GWh)**

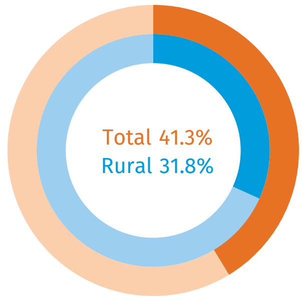


Source: ERA[13]

The single bulk supplier of electricity in Uganda, Uganda Electricity Transmission Company Limited (UETCL), purchased 4,329.4 GWh of electricity during the 2019/2020 fiscal year and sold 4,171.4 GWh, with transmission losses (approximately 4 per cent) accounting for the difference. Electricity sales are partially driven by exports to neighbouring countries including Kenya, Tanzania, Rwanda and the Democratic Republic of the Congo. During the 2019/2020 fiscal year, electricity exports amounted to 220.8 GWh, a 7 per cent decrease from the previous fiscal year.[14] The decline in exports was largely caused by declining demand in Kenya, which has been improving domestic generation and transmission capacities in the regions importing electricity from Uganda. The previous high demand in Kenya for electricity from Uganda was driven in part by an earlier price reduction of nearly 50 per cent on electricity from the latter. As such, Uganda has been gradually losing revenue from electricity exports.[15]

According to the World Bank estimates, the national rate of access to electricity in Uganda was 41 per cent in 2019, with almost 71 per cent access in urban areas and 32 per cent in rural areas (Figure 3). Access to electricity has been improving rapidly over the last few years, having stood at 19 per cent nationwide in 2015.[16] However, Uganda still has one of the lowest levels of per capita electricity consumption in the world at 215 kWh per year, compared to the Sub-Saharan Africa average of 552 kWh per capita and the world average of 2,975 kWh per capita.[17] Electricity consumption is dampened by significant electricity export volumes.

Figure 3. **Electrification Rate in Uganda in 2019 (%)**



Source: World Bank[16]

The demand for electricity has been growing at an average annual rate of 10–12 per cent. The number of customers connected to the grid has also been increasing rapidly, from a total of 801,667 in 2015/2016 to 1,620,505 in 2019/2020, driven primarily by the expansion of connectivity in the domestic sector.[17,18] Domestic peak demand had declined in 2020 from an average of 650 MW to approximately 530 MW due to the impact of the COVID-19 pandemic, but recovered later in the year and reached a maximum value of 689 MW in December.[15,19] In anticipation of growing demand, the Government has undertaken several large hydropower projects, including the aforementioned ongoing 600 MW Karuma hydropower project, as well as the 183-MW Isimba Falls hydropower plant commissioned in 2019.[20] A key element in the energy sector policy of Uganda is the Uganda Vision 2040 strategic plan, which identifies electricity generation as a key intervention for ensuring the socioeconomic transformation of the country. With Uganda having met the 2020 target of 30 per cent electricity access, the plan aims to reach 80 per cent access by 2040, targeting an increase of approximately 6 per cent year-on-year.[2]

Prior to 2001, all generation, transmission, distribution, sale, import and export of electricity in Uganda was managed by the Uganda Electricity Board (UEB), a mandated monopoly. In 2001, UEB was unbundled into three separate companies in line with the stipulations of the Electricity Act of 1999. The Uganda Electricity Generation Company Limited (UEGCL), the UETCL, and the Uganda Electricity Distribution Company Limited (UEDCL) are now each responsible for generation, transmission and distribution of electricity, respectively. In addition to UEGCL, generation is also carried out by a number of independent power producers (IPPs), including Eskom Uganda Limited and public-private partnerships (PPPs). Private companies also play a significant role in electricity distribution. These include Umeme Limited, West Nile Rural Electrification Company (WENRECo), Bundibugyo Electricity Cooperative Society (BECS), Kyegegwa Rural Energy Co-operative Society (KRECS), Pader-Abim Community Multi-Purpose Electric Co-operative Society (PACMECS), Kilembe Investments Limited (KIL), Hydromax and Kalangala Infrastructure Services Limited (KIS). The emergence of private distribution companies in recent years has been one of the factors behind the significant rise in electricity access across the country.[11,21]

The Electricity Regulatory Authority (ERA), established in 2000, is the legal supervisor of the electricity sector and is mandated by the Electricity Act of 1999 to issue licences for electricity generation, transmission, distribution, sale, import and export, in addition to establishing a tariff structure and approving rates of charges, among other functions. The UETCL negotiates prices with power generation companies through power purchase agreements (PPAs) subject to approval by the ERA. Power is sold to distribution companies at a bulk supply tariff (BST), reflective of the power purchase and transmission costs. The distribution companies then sell electricity to the end users in line with an ERA-approved tariff schedule. The setting and approval of end-user electricity tariffs considers changes in macro-economic factors such as fluctuations in international fuel prices, the variation of the currency exchange rate (UGK/USD), local and international inflation levels and energy generation mix.[1,21,22]

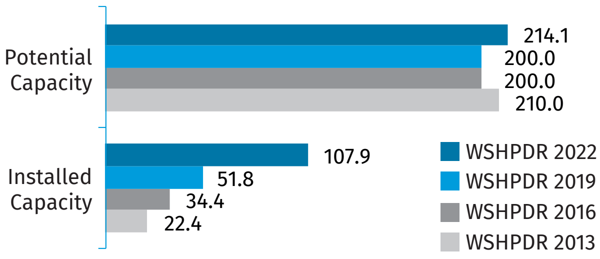
The largest electricity distribution agency in Uganda is Umeme Limited. Tariffs for end users purchasing electricity from Umeme Limited are updated quarterly, with tariffs for the period July–September 2021 ranging from 177.5 UGX/kWh (0.05 USD/kWh) to 816.9 UGX/kWh (0.23 USD/kWh).[23]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Uganda is hydropower plants with an installed capacity of up to 20 MW.[2] However, for the purposes of comparison with the *World Small Hydropower Development Report (WSHPDR) 2019*, the up to 10 MW definition of hydropower will also be referred to in the current chapter.

In Uganda, SHP plants are largely privately owned and operated by IPPs, with some supplying electricity to isolated grids. As of 2022, 25 SHP plants up to 20 MW were operating in Uganda with a total installed capacity of 186.0 MW. Of these, 20 plants were up to 10 MW, with a total installed capacity of 107.9 MW.[2,10,21,24] The most recent estimate of potential capacity for SHP of up to 20 MW was approximately 400 MW, while potential capacity for plants up to 10 MW is estimated at 214.1 MW, based on the combined total of existing SHP plants, ongoing projects and identified potential SHP sites.[2,21,25-27] This suggests that approximately 50 per cent of estimated SHP potential has already been developed in the country. Compared to the *WSHPDR 2019*, the installed capacity of SHP up to 10 MW in Uganda has more than doubled, due to the construction of many new SHP plants in recent years (Table 1). Meanwhile, the estimate of potential capacity for SHP up to 10 MW increased by approximately 7 per cent, due to more accurate data on existing SHP plants and planned projects (Figure 4).[27]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Uganda (MW)**



Source: Nabutsabi,[2] van der Ven,[21] *WSHPDR 2019*,[27] *WSHPDR 2013*,[28] *WSHPDR 2016*[29]

Note: Data for SHP of up to 10 MW.

Table 1. **List of Selected Existing Small Hydropower Plants in Uganda**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Kikagati	Isingiro District	15.57	Reservoir	Kikagati Power Company (KPC)	2022
Nyamasagani 1	Kyarumba, Kasese District	15.00	Run-of-river	Rwenzori Hydro (PVT) Ltd	2021
Nyamasagani 2	Kyarumba, Kasese District	6.00	Run-of-river	Nyamagasani 2 HPP Ltd	2021
Siti II Hydroelectric Power Station	Chesowari, Bukwo District	16.50	Run-of-river	Elgon Hydro Siti (Pvt) Limited	2019
Ziba-Kyambura Hydroelectric Power Station	Rubirizi District	7.60	Run-of-river	Ziba (U)	2019
Ndugutu Hydroelectric Power Station	Bundibugyo District	5.90	Run-of-river	Sindila Power Company Uganda Limited	2019
Sindila Hydroelectric Power Station	Bundibugyo District	5.25	Run-of-river	Sindila Power Company Uganda Limited	2019
Nkusi power station	Kyangwali, Hoima District	9.60	Run-of-river	PA Technical Services	2018
Nyamwamba Power Station	Kilembe, Kasese District	9.20	Run-of-river	South Asia Energy Management Systems (EMS) LLC	2018
Lubilia Power Station	Kawembe, Kasese District	5.40	Run-of-river	Lubilia Kawembe Hydro Limited	2018
Waki Power Station	Butiaba, Masindi District	4.80	Run-of-river	Hydromax Ltd	2018

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Mahoma Power Station	Mahoma, Kabarole District	2.70	Run-of-river	Mahoma Uganda Limited	2018
Bwindi	Buhoma, Kanungu District	0.06	N/A	Bwindi Community Micro Hydro Power Ltd	2018
Muvumbe power station	Maziba, Kabale District	6.50	Run-of-river	Muvumbe Hydro (U) Ltd	2017
Rwimi power station	Rwimi, Bunyangabu District	5.54	Run-of-river	Rwimi EP Company Limited	2017
Siti I Hydroelectric Power Station	Siti, Bukwo District	5.00	Run-of-river	Elgon Hydro Siti (PVT) Limited	2017
Kabalega Power Station/ Buseruka	Buseruka, Hoima District	9.00	Reservoir	Hydromax Ltd	2013
Nyagak power station	Paidha, Zombo District	3.50	Run-of-river	WENRECo	2012
Mpanga Power Station	Mpanga, Kamwenge district	18.00	Run-of-river	Africa Energy Management Systems EMS Mpanga Ltd.	2011
Kanungu Hydroelectric Power Station/ Ishasha	Kanungu, Kanungu district	6.60	Run-of-river	Eco Power Uganda Limited.	2011

Source: Nabutsabi,[2] ERA,[10,30] van der Ven,[21] Frontier Energy,[31,32] AKDN,[33] KHPL,[34] African Power Platform[35]

Table 2. **List of Selected Ongoing Small Hydropower Projects in Uganda**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Developer*	*Planned launch year*
Agbinika	Yumbe, Yumbe District	20.0	Run-of-river	N/A	2025
Nyagak II	Paidha, Zombo District	5.0	Run-of-river	UEGCL	2023
Achwa III	Achwa, Gulu District	10.0	Run-of-river	N/A	2022
Nengo Bridge	Nengo, Rukungiri District	6.7	Run-of-river	Jacobsen Elektro AS	2022
Nyagak III	Paidha, Zombo District	5.6	Run-of-river	UEGCL	2022

Source: van der Ven,[21] *WSHPDR 2019*,[27] Katutsi et al.[36]

In recent years, intensive SHP construction has been taking place in Uganda. As of 2020, there were 20 SHP projects in various phases of completion with a total potential capacity of 141.8 MW, of which 91.8 MW were for SHP of up to 10 MW; however, by 2022 three of these projects had been completed, including the 6 MW Nyamasagani-2 SHP plant, leaving the remaining undeveloped capacity up to 10 MW at 85.8 MW. Additionally, 20 potential SHP sites of up to 10 MW have been identified with a total estimated potential capacity of approximately 20.4 MW.[10,21,24-27] Several ongoing SHP projects and identified potential SHP sites are listed in Tables 2 and 3, respectively.

Table 3. **List of Selected Potential Small Hydropower Sites in Uganda**

Name	*Location (district)*	*Potential capacity (MW)*	*Type of site (new or refurbishment)*
Kaka	Kasese	7.20	New, preliminary technical studies carried out under Greenewus Energy Africa Ltd
Rwizi	Mbarara	1.00	New, preliminary technical studies carried out under Ntama Bamwine Hydropower Company Ltd.
Nyahuka	Bundibugyo	0.65	New, preliminary technical studies carried out under AERDP by MEMD
Sezibwa	Mukono	0.50	New, preliminary technical studies carried out under AERDP by MEMD
Tokwe	Bundibugyo	0.40	New, preliminary technical studies carried out under AERDP by MEMD

Source: ERA,[25] CSTD,[26] *WSHPDR 2019*[27]

The cost of SHP development in Uganda is considerable, averaging approximately USD 3–4 million per installed MW.[2] Nevertheless, SHP development is considered an important element of poverty reduction efforts in Uganda, especially for isolated rural communities suffering from poor or non-existent connectivity to the national grid.

RENEWABLE ENERGY POLICY

The Renewable Energy Policy of Uganda, adopted in 2007, aims to increase the use of modern renewable energy sources through the introduction of the feed-in tariff (FIT) remuneration mechanism and standardization of PPAs. The objective is to encourage both individual investors and companies to invest in renewable energy generation in Uganda. The policy mandated the publication of a standardized PPA with FITs determined periodically; the creation of a renewable energy department; promotion of biofuel cultivation, in collaboration with the National Forestry Authority (NFA) and Ministry of Agriculture, Animal Industry and Fisheries (MAAIF); and the development of appropriate legislation and financial incentives for the production of biofuels.[37]

Renewable Energy Feed-in Tariffs (REFITs) introduced under the Renewable Energy Policy apply to renewable energy power plants of installed capacity of 0.5–20 MW, including

SHP plants. However, to qualify for REFIT, renewable energy projects must be connected to the national grid and must represent the development of additional capacity, whether on existing power plants or through the construction of a new power plant. Existing capacities are thus excluded from applying for support under the REFIT programme. The REFIT should be able to translate into cash revenue that will not require the investor to resort to a capital subsidy and be included in the standardized PPA. Initially, REFITs were structured to differentiate between peak, shoulder and off-peak prices, to reflect the higher value of power in the peak period, as well as between short-to-medium and long-term prices to reflect the higher risk of load shedding in the short to medium term. Subsequently, REFITs were simplified to a single rate based on installed capacity only.[2,37,38]

For the period 2021-2023, base REFIT tariffs for hydropower of 0.5–20 MW were set as follows, with a 20-year guaranteed payment period:

- 0.5–5 MW: 0.0792 USD/kWh;
- 5–10 MW: linear tariff structure ranging from 0.0751-0.0792 USD/kWh, with each 0.1 MW increment assigned a progressively lower tariff;
- 10–20 MW: 0.0751 USD/kWh.[38]

Further financial support for renewable energy projects became available with the adoption of the Global Energy Transfer Feed-in-Tariff (GET-FIT) in 2013. The GET-FIT is applied on top of the REFIT as a result-based subsidy on a per kWh basis, to cover the difference between the REFIT and the Levelized Cost of Electricity (LCOE). GET-FIT is assigned in the form of grants through a competitive bidding process.[2,39] The significant recent improvements in the distribution and access to electricity in Uganda are in large part owed to the favourable regulatory environment created by the Renewable Energy Policy.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Developers of renewable energy sources apply for a generation licence or licence exemption with the ERA and applications are processed within a maximum of 180 days following submission. Additional licensing bodies include the Directorate of Water Resources Management (DWRM) for the water abstraction permit; the National Environment Management Authority (NEMA) for the environmental permit; and UETCL, which concludes the PPA agreement with the power producer. The licensing process for SHP also involves the publication of notices in the National Gazette and the national newspaper to solicit any potential objections to the project from other potential stakeholders. The Hydro Power Association of Uganda (HPAU), a non-profit organization that brings together private hydropower development companies in Uganda, is involved in the promotion of and lobbying efforts for SHP.[40,41]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change projections for Uganda under RCP4.5 predict little change in annual precipitation, with fluctuation within the range of ±10 per cent by 2065–2095, relative to 2015. Seasonally, large increases in winter rainfall of upwards of 100 per cent are possible, while regionally, a decrease of up to 20 per cent is likely in the Lake Victoria area. Under RCP8.5, significant decreases of up to 30 mm per month are possible in the southern part of the country by 2065–2095.[6] As Uganda is heavily dependent on hydropower, fluctuations and changes in regional precipitation distribution could have potentially far-reaching effects. In 2003–2007, a particularly severe drought decreased hydropower generation in the country by over 60 per cent.[2] According to some calculations, available hydropower capacity may decline by as much as 26 per cent by 2050 relative to 2025, although other models predict an increase of approximately 15 per cent over the same period. The uncertainty of projections suggests that the impact of climate change on hydropower will be manageable as long as the Government maintains course with its current large-scale expansion plan in the sector.[6]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Although the development of SHP in Uganda has accelerated in recent years, it still faces a number of significant obstacles, including the following:

- Access to electricity primarily hampered by poor transmission and distribution infrastructure despite growth of generation capacity;
- Potential for adverse environmental impacts due to institutional and legal weaknesses, in particular poorly implemented environmental and social impact assessments (ESIA);
- Bureaucratic, complex and slow land acquisition process that affects overall project costs and timely construction of transmission line infrastructure;
- Limited local manufacturing capability for hydropower equipment as well as insufficient implementation experience and technical capacity;
- The need for substantial upfront investment capital;
- Social concerns including the resettlement and compensations for populations affected by development projects.

Factors enabling SHP development in Uganda include:

- The 'unbundling' of the state-owned Uganda Electricity Board (UEB);
- The establishment of a Rural Electrification Agency (REA) by the Government of Uganda to promote on-grid and off-grid rural electrification led by the private sector;
- Government investment in least-cost power technologies to provide adequate and reliable service;

- Collaboration with the East African Community on regional power interconnection;
- Conducive regulatory environment and incentives aimed at diversifying the country's generation mix.

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Zambia

Ernest Banda, Kangwa Bwembya, Reynolds Mukuka and Oscar Sinkala, ZESCO Ltd.

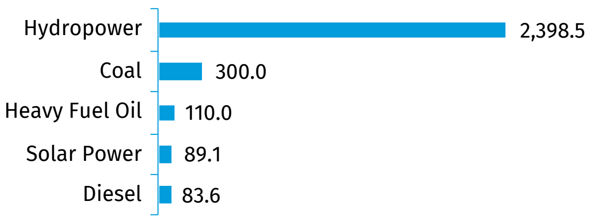
KEY FACTS

Population	17,885,422 (2020)[1]
Area	752,612 km^2[2]
Topography	The country is located on the great plateau of Central Africa, at an average altitude of 1,200 metres and rises to a higher plateau in the east. The country has three main topographical features: mountains, with an altitude of at least 1,500 metres; a plateau, with an altitude ranging from 900 metres to 1,500 metres; and lowlands, with an altitude of 400–900 metres.[3]
Climate	There are three seasons in Zambia: cool and dry from May to August, hot and dry from September to November and warm and wet from December to April. In the warm wet season, frequent heavy showers and thunderstorms occur. Average temperatures are moderated by the height of the plateau. In the cool season maximum temperatures vary from 15 °C to 27 °C, with morning and evening temperatures as low as 6–10 °C and occasional frost on calm nights in valleys and hollows which are sheltered from the wind. During the hot season maximum temperatures range from 27 °C to 35 °C.[4]
Climate Change	Zambia has continued to experience climate change and climate variability. The projected climate change impacts include: rises in temperature, shifts in precipitation and possible increases in the frequency and intensity of weather events. The country has experienced some of its worst droughts and floods in the last two decades. The mean annual temperature in Zambia has increased by 1.3 °C since 1960, representing an average increment rate of 0.29 °C per decade. Meanwhile, the mean annual rainfall over the country has decreased by an average rate of 1.9 mm per month (2.3 per cent) per decade since 1960. The mean annual temperature is projected to increase by 1.2–3.4 °C by the 2060s and by 1.6–5.5 °C by the 2090s. The proportion of total rainfall coming from extreme precipitation events, sometimes resulting in flooding, is expected to increase. The future trends in the country are towards higher average temperature, erratic precipitation and possible decrease in total rainfall.[3]
Rain Pattern	Zambia receives moderate rainfall ranging from an annual average of approximately 600 mm in the south of the country to over 1,400 mm per year in the north. The country's annual average rainfall is 1,000 mm. The rainfall pattern over the whole country is similar, with most precipitation falling between November and March, but the amount of rain varies considerably. In the north of the country rainfall is 1,250 mm or more a year, decreasing southwards to Lusaka where it is approximately 750 mm annually. South of Lusaka rainfall is dictated more by the east and south-east trade winds. Rainfall in this area is 500–750 mm.[5]
Hydrology	The country has five main rivers: Zambezi, Kafue, Luangwa, Luapula and Chambeshi. The five main river basins incorporate the several small river basins at which small hydropower potential is vast. The country's major lakes are Tanganyika, Mweru, Mweru Wa Ntipa, Bangweulu and the artificial lakes include Kariba and Itezhi-tezhi. Large hydropower plants are mainly located in the lower areas of the above catchments, while the small hydropower potential is mainly concentrated in the upper areas.[3,6]

ELECTRICITY SECTOR OVERVIEW

The electricity generation mix in Zambia is predominantly made up by hydropower. In the fourth quarter of 2019, of the total installed capacity of 2,981 MW hydropower accounted for 80 per cent (Figure 1). The remainder of the generation mix was composed of coal (300 MW, 10 per cent), heavy fuel oil (110 MW, 4 per cent), solar power (89 MW, 3 per cent) and diesel (84 MW, 3 per cent).[7]

Figure 1. **Installed Electricity Capacity by Source in Zambia in 2019 (MW)**

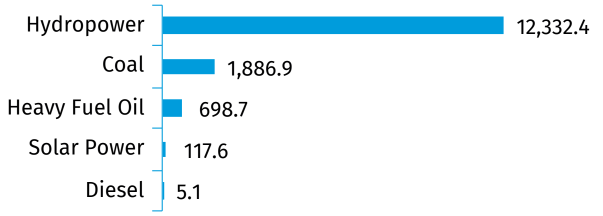


Source: ERB[9]

In 2019, the country's installed capacity increased to 2,981.2 MW from 2,898.2 MW in 2018, representing a near 3 per cent increase. This was mainly attributed to the commissioning of the 54.3 MW Bangweulu and 34 MW Ngonye solar power plants as well as the 67 kW of solar-powered micro-grids. On the other hand, the Zambia Electricity Supply Corporation (ZESCO) decommissioned 5.28 MW of diesel power plants, including: Kabompo (2.0 MW), Zambezi (1.4 MW), Mufumbwe (0.8 MW), Lukulu (0.3 MW) and Chavuma (0.8 MW). The diesel decommissioning was largely motivated by the connecting of the districts to the national grid.[9]

Despite the increase in installed capacity, the generation sent out to the grid declined from 16,189 GWh in 2018 to 15,040 GWh in 2019, reflecting a 7 per cent decrease. This was due to a poor rainfall pattern recorded in the 2018/2019 rainy season. Of the total generation in 2019, hydropower accounted for 82 per cent (Figure 2).[9]

Figure 2. **Annual Electricity Generation by Source in Zambia in 2019 (GWh)**



Source: ERB[9]

The electricity industry in Zambia is governed by the Electricity Act of 1995 and the Electricity Amendment Act of 2003. The electricity industry was liberalized in 1995 to attract investment in power generation, transmission and distribution. Currently, it consists of the vertically integrated public utility company ZESCO Limited, independent power producers (IPPs) and power distribution companies. These entities are responsible for the generation, transmission, distribution and supply of electricity. Private sector players that provide services include Copperbelt Energy Corporation (CEC), Lunsemfwa Hydro Power Company, Maamba Collieries Ltd and Zengamina.

ZESCO owns the four main hydropower plants located in the southern part of the country: 990 MW Kafue Gorge, 720 MW Kariba North Bank, 108 MW Victoria Falls and the newly commissioned 120 MW ITT. A fifth large hydropower plant is owned by Itezhi Tezhi Power Corporation (120 MW). The country also has operational small hydropower (SHP) plants with a combined installed capacity of 89.8 MW and owned by ZESCO and IPPs.[9]

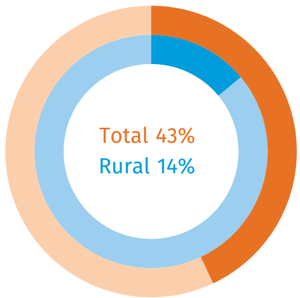
The electricity sector is overseen by the Ministry of Energy (MoE), which provides policy guidance, while the Office for Promoting Private Power Investment (OPPPI) has the role of promoting private investment in power projects. The sector is regulated by the Energy Regulation Board (ERB), which is responsible for licensing, tariff setting and monitoring the quality of supply and service standards. The Rural Electrification Authority (REA) is a statutory body that was created through the enactment of the Rural Electrification Act 2003 to increase access to electricity in rural areas.[9]

The general outlook for the electricity industry in Zambia is positive both in the short and long term. To address the current power deficit, ZESCO established a special purpose vehicle (SPV), Kafue Gorge Lower Power Development Corporation (KGLPC), to spearhead the construction of the 750 MW Kafue Gorge Lower hydropower plant at an estimated cost of USD 2.2 billion. The first unit of the plant was commissioned in July 2021.[8]

Zambia is divided into 10 provinces: Central, Copperbelt, Western, Eastern, Luapula, Lusaka, Muchinga, Northern, North-Western and Southern. Copperbelt and Lusaka are the only provinces with access to electricity above 50 per cent, while many other provinces have 10 per cent or less.[9]

In 1994, the Government established the Rural Electrification Fund (REF) by committing the sales tax to electricity and has been trying to increase the electrification rate in rural areas by executing projects funded by REF. At that time, the household electrification rate was approximately 20 per cent countrywide, and only 2–3 per cent in rural areas. As of 2019, 43 per cent of the population had access to electricity, and 14 per cent of rural population had access (Figure 3).[11]

Figure 3. **Electrification Rate in Zambia in 2019 (%)**



Source: World Bank[11]

The Government has been strengthening policies and institutions related to rural electrification. In December 2003, the Rural Electrification Act was ratified to establish the REA and to improve the management of the REF.[10] The Government, through the Rural Electrification Master Plan (REM), has set a target to increase electrification rates to 66 per cent of households by 2030, of which 90 per cent would be for urban areas and 51 per cent for rural areas.[12]

Despite the country's vast renewable and non-renewable energy sources, few of these have been developed to improve the attractiveness of the energy sector and to transfer the benefits for industrial expansion, employment creation and poverty reduction.[11,12] The development of large hydropower plants in Zambia has historically been driven by the industrial needs of energy for mining, whereas SHP development has historically been initiated to provide power to areas that are far from the national grid, areas that were extending from the Southern Province towards the Copperbelt.

ZESCO transmits power at various voltage levels, namely 330 kV, 220 kV, 132 kV, 88 kV and 66 kV.[13] These voltage levels are stepped down to 33 kV and 11 kV for distribution at substations. The main 330 kV transmission lines are running north to south in the middle of the country because the copper mines, which are the largest load centres, are located in the north and the main generation plants are located in the south. Copperbelt Energy Corporation (CEC) has most of the mining and large industrial customers, who are supplied at 66 kV or higher voltage in Copperbelt Province, while small customers within the CEC service area are supplied by ZESCO. In 2019, ZESCO recorded annual average transmission and distribution losses of 5 per cent and 11 per cent, respectively.[9] In off-grid locations, small IPPs and non-governmental organizations (NGOs) are supplying electricity with either SHP or diesel power plants through the isolated distribution network.

The country has made progress in gravitating towards cost-reflective electricity tariffs through an upward adjustment of tariffs by 75 per cent implemented in 2017, following the electricity crises of 2015 and 2016. This is after Zambia was identified as having the lowest electricity tariffs in sub-Saharan Africa in 2014.[13] In 2019, the ERB commissioned a cost-of-service study to establish the efficient cost of supplying power to various customer categories and determine the cost-reflective tariff levels. [7,14] The 2020 tariff rates for residential customers, commercial customers and social services are reflected in Table 1. Fixed monthly charges were abolished in 2020.[15]

Table 1. **Electricity Tariffs in Zambia in 2020**

Customer category	*Consumption band (kWh/month)*	*Final electricity price (ZMW (USD) per kWh)*
Residential	R1 < 100	0.47 (0.026)
	R2 101 – 300	0.85 (0.047)
	R3 > 300	1.94 (0.110)
Commercial	C1 < 200	1.07 (0.059)
	C2 > 200	1.85 (0.100)
Social Services	Schools, hospitals, orphanages, churches, water pumping & street lighting	1.19 (0.066)

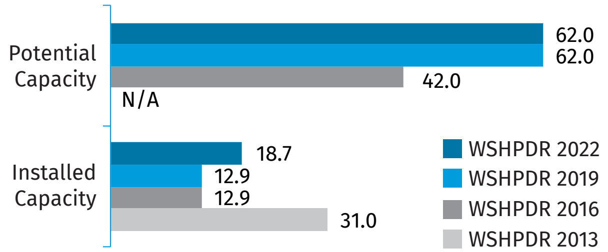
Source: Energy Regulation Board[15]

SMALL HYDROPOWER SECTOR OVERVIEW

Zambia classifies SHP plants as units between 0.5 MW and 20 MW. Plants less than 0.5 MW are regarded as micro-hydropower plants. Plants from 20 MW to 100 MW are classified as medium hydropower plants and those having installed capacities greater than 100 MW as large hydropower plants. Despite the national definition, this chapter takes the 10 MW definition, keeping consistent with previous editions of the *World Small Hydropower Development Report* (*WSHPDR)* for reasons of accurate comparison.

Based on the up to 10 MW definition, there are 18.7 MW of SHP capacity. The increase in installed capacity compared to the *WSHPDR 2019* is mainly attributed to the commissioning of the 10 MW Musonda and 0.64 MW Kasanjiku SHP plants in 2020. There has been no change in potential capacity estimates (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Zambia (MW)**



Source: ERB,[7,14,16] JICA,[10] Ministry of Energy and Water Development,[11] ZESCO LTD,[12] *WSHPDR 2013*,[17] *WSHPDR 2016*,[18] *WSHPDR 2019*[19]

Note: Data for SHP up to 10 MW.

The SHP sector in Zambia is currently undergoing a rehabilitation transformation, with the scaling-up of old plants and development of new plants being in various stages of project development. As of 2021, based on the local definition of SHP up to 20 MW, the total installed capacity for micro- and small hydropower plants stood at 60.5 MW (Table 2).[9] ZESCO Ltd is currently rehabilitating two SHP plants: the Chishimba plant is being rehabilitated and upgraded from 6 MW to 15 MW and the old Lusiwasi 12 MW plant is being replaced by new plants upstream and downstream with capacities of 15 MW and 86 MW. The Musonda plant was upgraded from 6 MW to 10 MW in 2020. In 2019, REA commissioned the 0.64 MW Kasanjiku plant in Mwinilunga district.[20]

Table 2. **List of Installed Small Hydropower Plants in Zambia**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Musonda	Mansa	10.000	29	Run-of-river	ZESCO	2020
Lusiwasi Upper 11	Serenje	15.000	90	Run-of-river	ZESCO	2020
Kasanjiku13	Mwinilunga	0.640	10	Run-of-river	REA	2019
Lunzua	Mbala	14.800	248	Run-of-river	ZESCO	2015
Shiwang'andu	Shiwang'andu	1.000	14	Run-of-river	ZESCO	2012

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Zengamina	Ikelenge	0.750	17	Run-of-river	Zengamina Power Company	2007
Mporokoso	Mporokoso	0.005	3	Run-of-river	Private Local Developer	2007
Mayukwayukwa (not operational since 2015)	Kaoma	0.028	2	Run-of-river	UNHCR	1993
Mutanda	Solwezi	0.003	–	Run-of-river	Mutanda Evangelical Centre	1990
Sachibondu	Mwinilunga	0.015	–	Run-of-river	Private Local Developer	1987
Lwawu	Mwinilunga	0.050	–	Run-of-river	Lwawu Mission	1984
Mangango	Kaoma	0.017	–	Run-of-river	Mangango Mission	1960
Lusiwasi	Serenje	12.000	90	Run-of-river	ZESCO	1967 (1974)
Chishimba	Kasama	6.000	–	Run-of-river	ZESCO	1959 (1971)
Nyang'ombe	Mwinilunga	0.073	–	Run-of-river	Nyang'ombe Cooperative	–
Katibunga	Katibunga	0.080	–	Run-of-river	Katibunga Mission	–

Note: Based on Zambian SHP definition of up to 20 MW.

Source: ERB,[7,16] JICA,[10] Ministry of Energy and Water Development,[11] ZESCO LTD[14]

With electricity demand in Zambia projected to increase at a rate of approximately 4 per cent per annum and given the current national and regional power deficit, there is need to deal with various bottlenecks in the hydropower development process in Zambia.[21] ZESCO hydropower database, updated in 2016, indicates that the statistics of theoretical hydropower potential was on the order of 8,000 MW.[14] However, only 30 per cent of this potential has been developed to date.[11] Several SHP plants are in planning at various stages of development (Table 3).

Table 3. **List of Selected Planned Small Hydropower Projects in Zambia**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Developer*	*Stage of development*
Mumbururuma	Mporokoso	18.8	33.1	Run-of-river	ZESCO	Pre-feasibility
Chishimba	Kasama	15.0	–	Run-of-river	ZESCO	Implementation
Mbulumotuta	Mporokoso	12.3	87	Run-of-river	TBA	Pre-feasibility
Kapamba	Mpika	12.0	175	Run-of-river	TBA	Feasibility
Kakonko	Kawambwa	8.0	73	Run-of-river	ZESCO	Pre-feasibility

Source: ZESCO,[22] UNIDO,[23] OPPPI,[24] Hangzhou Guowang Technology Co. Ltd.,[25] JICA[12]

RENEWABLE ENERGY POLICY

The policy framework governing renewable energy in Zambia is driven by the National Energy Policy. It was formulated in 1994 and sought to promote optimal supply and utilization of energy for socioeconomic development in a safe and healthy environment. Due to the realization of the strategic nature and integrated nature of energy in economic development, the National Energy Policy 1994 has been revised to ensure that the role of energy in relation to other economic dynamics are taken care of. In particular, emerging cross-cutting aspects related to sustainable industrial development were not addressed in the National Energy Policy 1994.[26] The National Energy Policy of 2019 recognizes the critical role played by renewable energy in poverty alleviation and national development. The policy also considers the need for climate change mitigation and adaptation measures while advancing the sustainable development of the sector.[14]

The demand for renewable energy has seen significant growth in recent years as the market has been exploring alternative sources of energy, with renewable energy proving to be a viable alternative. In 2016, the ERB completed developing The Renewable Energy Regulatory Framework (RERF). The RERF was developed in line with the National Energy Policy (2008), the Biofuels Regulatory Framework, the Regulatory Framework for Off-Grid Systems, the Renewable Energy Feed-in-Tariff (REFIT) Strategy and other relevant legislation. These documents individually strive to facilitate the implementation and diversification of the energy sector to promote renewable energy technologies and improve access to modern forms of energy. The RERF puts all these requirements in one document covering renewable energy-based electricity generation with the aim of achieving the following:

- Facilitating implementation of the Government's policy to diversify the energy mix and provide modern forms of energy to rural communities;

- Consolidating and rationalizing existing regulatory frameworks;
- Promoting investment by having a clear regulatory framework that outlines entry requirements for the sector;
- Providing clear internal guidelines to facilitate renewable energy deployment.[14]

In 2016, the Government of the Republic of Zambia and Kreditanstalt für Wiederaufbau (KfW) initiated the Global Energy Transfer Feed-in Tariff (GETFIT) programme. The programme is designed to leverage private sector investment into renewable energy generation projects. It intends to fast-track a portfolio of small-scale renewable energy generation projects, up to a maximum of 20 MW each, including SHP projects promoted by private developers. It is envisaged that the full implementation of the GETFIT programme will be done as soon as the REFIT Strategy is launched and is also contingent on the finalization of the following support mechanisms:

- Development of the procurement guidelines;
- Development of the Standard Implementation Agreement;
- Agreeing on the quantum of the GETFIT subsidy on the REFITs.[8]

To develop a balanced REFIT, various methodologies and options were considered. Zambia shall apply a methodology following the cost-based approach, which implements a rate of return methodology and payment calculated using costs and return expectations of project investors.[27] In 2020 39 SHP sites were approved for feasibility study rights under the program.[15]

Licences to generate electricity from renewable energy sources are to be issued by the ERB. The generation licence essentially grants the producer the right to develop, finance, construct and operate the power plant, as well as the right to sell the electricity to the off-taker. ZESCO shall be the designated buyer of all the power delivered under the REFIT programme. The details of the off-take arrangement shall be set out in a standardized, technology-neutral power purchase agreement (PPA). The term of the PPA shall be at least 20 years from the commercial operation date.[26]

The greenhouse gas (GHG) emissions of Zambia are relatively low given the country's reliance mostly on hydropower for electricity generation. However, recently, more conventional energy sources have been commissioned such as the Maamba coal-fired power plant, which started operation in 2016. As a result, CO_2 emissions per capita have been slowly increasing since 2007. Furthermore, approximately 70 per cent of energy consumed in Zambia comes from firewood and charcoal, which is both unsustainable and unhealthy for consumers. Under the framework of the Intended Nationally Determined Contributions (INDC) to the 2015 Climate Change Agreement, Zambia intends to reduce its CO_2eq emissions by 25 per cent by 2030 compared to the baseline business-as-usual scenario through domestic efforts with limited international support, and by 47 per cent with substantial international support. This is equal to a total emissions reduction of 38 MtCO_2eq, which will require an investment of USD 50 billion by 2030. This will be achieved by implementing three programmes driven by the country's Climate Response Strategy and supported by the National Policy on Climate Change and national development policies, including energy, forestry, agriculture, water, town and country planning, sanitation and transport.[28]

Zambia does not have a national uniform tariff and developers may charge different tariffs subject to regulatory approval. However, retail tariffs must be approved by the ERB, which uses the revenue requirement or rate of return methodology. In principle, cost-reflective tariffs may be proposed by developers. The country does not yet have an electricity pricing regime for behind-the-meter storage applications. Apart from the tariff, ERB also approves customer connection charges. The ERB draws its mandate to determine electricity tariffs from the Electricity Act, Cap 433, Section 8.[29]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The relevant policies and regulations in Zambia that govern developments such as SHP projects include the following:

- Zambia National Energy Policy (2019);
- Electricity Act No. 14 of 1995;
- Energy Regulation Act Cap 436 (2003);
- Rural Electrification Act (2003);
- Zambian Grid Code 2006;
- REFIT Strategy (2017);
- Water Resources Management Act (2011);
- Environmental Management Act (2011);
- Lands Act (2015);
- National Heritage Conservation Commission Act (1989).

The feasibility study rights for the development of SHP plants in Zambia are granted by the MoE through the following process:

- Application for the issuance of feasibility study rights to the Permanent Secretary;
- OPPPI/DOE assessment of the application;
- Interim rapid grid assessment and OPPPI/DOE recommendation;
- Permanent Secretary issues a letter granting feasibility study rights.

Permitting and licensing of SHP plants involves the acquisition of land that in most cases sits under customary tenure in Zambia. Hydropower projects also require water rights and stringent health safety and environmental standards are compulsory to prevent accidents during construction or operation of power plants. All projects must comply with requirements from the regulatory government agencies. The steps for obtaining a licence for combined generation, distribution and supply of electricity for solar and hydropower plants are as follows:

- Business registration with the Patents and Companies

Registration Agency (PACRA);
- Securing land tenure rights;
- Clearance from the Department of National Parks and Wildlife;
- Concession from the National Heritage Conservation Commission (NHCC);
- Environmental permit from the Zambia Environmental Management Authority (ZEMA);
- Water use permit for power generation from the Water Resource Management Authority (WARMA);
- Investment endorsement from the ERB;
- Tariff approval from the ERB;
- Issuance of a combined licence for generation, transmission, distribution and supply of electricity.

COST OF SMALL HYDROPOWER DEVELOPMENT

The capital cost of SHP development in Zambia depends on the size of the project and existing site conditions, such as topography, geology and hydrology. Based on the estimates of planned and recently commissioned plants, capital cost ranges from USD 8.7 million for a less than 1 MW plant to USD 76 million for an 18.8 MW plant. Costs per MW of installed capacity range from USD 2.4 million to USD 14.5 million.[10,16,21,22,23,24,25]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

GETFIT Zambia has received significant contributions from the Government of Germany, which will ensure the successful implementation of the first phases of the programme. The largest share of the funds (approximately 70 per cent) will be used for subsidies for SHP projects. In the GETFIT Zambia context, such subsidies are referred to as Viability Gap Funding, designed to close the gap between the offered power tariffs and the tariff necessary for investors to achieve the required rate of return on investment. This way, substantial amounts of private capital can be leveraged to the Zambian power sector.[30]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Hydropower is directly affected by climate change in the sense that the latter alters the amount of water available for generation and potentially the seasonal distribution of runoff. Climate change has an impact on firm energy yield, the cost of energy production and plant operations. Furthermore, climate change will also affect design risks for new hydropower projects in terms of changes that will result in greater uncertainty concerning extreme weather phenomena such as flooding and droughts, which will in turn affect the project costs. Based on the report on the climate impacts on hydropower in Africa, the regional mean hydropower capacity factor is projected to decrease due to climate change by approximately 3 per cent by the year 2099 compared to the baseline period of 2010–2019.[31]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Notwithstanding the barriers and challenges highlighted, SHP development is expected to accelerate in response to recent initiatives, including studies highlighting the magnitude of the untapped SHP potential in Zambia, the transparent permitting processes, new financial incentives and the introduction of better policies. In many cases, SHP development can be achieved with minimal impact, thus supporting the country's economic and environmental goals. Further, it is anticipated that SHP will form part of the solution to the growing demand for a rural electrification programme in the country.

The Zambian hydropower industry presents great opportunities for investment and growth. However, the industry also faces challenges that include, among others, the following:
- Water resources development and management: Lack of the hydrological data necessary to adequately asses the available potential on the small river basins;
- Energy policy: Lack of a comprehensive energy policy to deal with the requirements of private plants interfacing with the national grid, for example, the feed-in-tariff has affected the process of private sector participation in hydropower generation especially SHP, which are vital for the sustainable development of rural districts;
- Transmission of power: The challenge of the cost of transporting electricity generated from renewable sources through the transmission system to the consumption centres of the country affects the bankability of projects considering that suitable hydropower potential is mainly located in remote areas of Zambia;
- Tariff structure and return on investment: The tariff structure in Zambia is still not cost-reflective;
- Financing: Access to capital markets remains a challenge for the general local private sector investors newly entering the hydropower industry. Due to the high capital investments required in hydropower, the development of SHP plants has not progressed at the pace required to meet various load requirements;
- Inability to attract investment: The challenges related to energy policies, feed-In-tariffs and cost-reflective tariffs directly affect the ability to attract investment;
- Access to sites: The poor road networks in rural areas make it difficult and expensive to carry out any work.

Despite of the barriers stated above, the hydropower industry presents great opportunities for investment and growth. In addition, the Government of Zambia has put in place enabling polices and regulations meant to attract investments in energy sector. The key enablers for the development of SHP include, among others, the following:

- The power sector was declared a priority sector under the Zambia Development Agency Act No. 11 of 2006 through the issuance of SI No. 15 of 2011. This regulation declares the building of mini-hydropower plants, solar power, thermal and hydropower plants eligible for fiscal incentives;
- The GEFIT Zambia programme aims to facilitate private sector investment in small- and medium-scale renewable energy IPPs in Zambia;
- The REFIT strategy is aimed at accelerating private investments in small- and medium-sized renewable energy projects in order to increase the number of players in the electricity subsector and ultimately increase access to clean energy services;
- Transparent project allocation procedures, with projects being committed to developers by way of feasibility study rights granted by the MoE;
- Economic incentives to encourage investment, including fiscal incentives (e.g., tax incentives), non-fiscal incentives (risk cost sharing, support of land acquisition) and a capital-smart subsidy (for projects developed under the REA);
- Migration towards cost-reflective tariffs from tariffs that were highly subsidized was commenced in 2017;
- Sufficient and sustained market for the generated electricity, with the demand for power growing at a rate of approximately 4 per cent per annum.

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Zimbabwe

Shorai Kavu, Ministry of Energy and Power Development

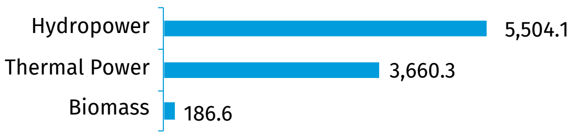
KEY FACTS

Population	14,645,000 (2019)[1]
Area	390,760 km^2 [2]
Topography	Zimbabwe is a landlocked country lying entirely within the tropics. It straddles an extensive high inland plateau that drops northwards to the Zambezi Valley, where it borders Zambia, and drops southwards to the Limpopo Valley and the border with South Africa. Zimbabwe has an average elevation of 1,500 metres above sea level and the highest peak is in the Nyangani Mountains to the north-east of the country at 2,592 metres.[3,4]
Climate	The hot season occurs from mid-August to mid-November, with daytime temperatures ranging from 26 °C to 36 °C. The rainy season is from mid-November to mid-March and can be interrupted by 4-5 dry spells. The cool season occurs from mid-May to mid-August with mild daytime temperatures ranging from 20 °C to 29 °C. The dry season occurs from mid-March to mid-May, with mild and sunny weather and temperatures ranging from 23 °C to 31 °C.[4]
Climate Change	Zimbabwe, like many other areas of Southern Africa, has increasingly been exposed to rising temperatures and increased rainfall variability due to a changing climate.[4]
Rain Pattern	The maximum rainfall is received in the eastern highlands, with annual rainfall of more than 1,000 mm. The Highveld receives an annual average of more than 500 mm of rainfall. The climate and rainfall patterns of Southern Africa have varied greatly for at least the last three centuries, leading to recurrent droughts of varying severity.[3,4]
Hydrology	Zimbabwe has six drainage basins. The largest being the Zambezi and the Limpopo basins. The western parts of the Matabeleland region are connected to the Okavango inland drainage basin through the Nata River. Parts of the Mashonaland and Masvingo regions drain through the Save River into the Indian Ocean. Two other drainage basins covering parts of the Manicaland region and draining into the Indian Ocean through Mozambique are the Pungwe River to the north and the Buzi River to the south.[3,5]

ELECTRICITY SECTOR OVERVIEW

The electricity sources in Zimbabwe include coal for thermal generation, large hydropower, small hydropower (SHP), solar power and diesel/petrol for backup systems.[6] In 2018, a total of 9,351 GWh of electricity was generated in the country, including by individual power producers (IPPs) (Figure 1). Generation from power plants owned by Zimbabwe Power Company (ZPC) increased by 25 per cent from 7,216 GWh in 2017 to 9,037 GWh in 2018, mainly due to the increased water allocation at the Kariba Dam.[7] Renewable energy generation made up 61 per cent of all electricity generation in 2018 (5,688 GWh).[7] This is a significant increase from 2017, when renewable generation made up 50 per cent. The individual contributions from the power plants in 2018 are depicted in Table 1.

Figure 1. **Annual Electricity Generation by Source in Zimbabwe in 2018 (GWh)**



Source: ZERA[7]

Note: Data for solar power generation from IPPs and off-grid sources is not publicly available and thus not included.

Table 1. **Annual Electricity Generation from ZPC and IPPs**

Power plant	*Energy source*	*Generation 2017 (GWh)*	*Generation 2018 (GWh)*
ZPC-owned plants			
Hwange	Coal	3,202.0	3,425.0
Kariba	Hydropower	3,850.0	5,377.0
Harare	Coal	75.0	66.0

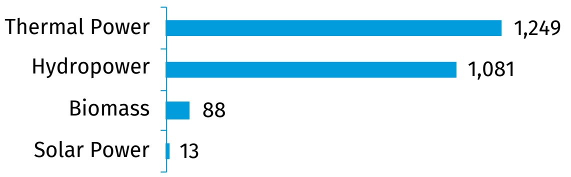
Power plant	*Energy source*	*Generation 2017 (GWh)*	*Generation 2018 (GWh)*
Munyati	Coal	38.0	81.0
Bulawayo	Coal	51.0	88.0
IPPs			
Nangani Renewable Energy	Mini-hydropower	111.0	112.0
Hippo Valley Estates	Biomass	0	63.2
Triangle Limited	Biomass	3.3	83.9
Border Timbers	Biomass	0	0
Chisumbanje	Biomass	10.8	39.5
Dema Emergency Peaking Plant	Diesel	48.2	0.2
Kupinga	Mini-hydropower	7.9	13.1
Claremont	Mini-hydropower	0.4	1.7

Source: ZERA[7]

As of 2021, Zimbabwe had a total installed capacity of 2,431 MW, of which 1,050 MW was from the Kariba South hydropower plant, 920 MW from the Hwange thermal power plant, a combined 329 MW from small coal-fired thermal plants (Harare, Bulawayo and Munyati) and 132 MW were contributed by IPPs and community-owned off-grid systems (Figure 2, Table 2). The capacity from bagasse was for the private use of sugarcane and ethanol producing firms. Available capacity stood at approximately 1,924 MW.[6,8]

The Kariba South hydropower plant extension project of 300 MW was completed in 2018 raising the plant's installed capacity to 1,050 MW.[9,10] The Hwange thermal power plant extension project with a capacity of 600 MW is under construction and expected to have the first 300 MW unit in operation by 2022 despite delays due to COVID-19 restrictions.[10,11]

Figure 2. **Installed Electricity Capacity by Source in Zimbabwe in 2021 (MW)**



Source: AfDB,[6] MoEPD[8]

Table 2. **Installed, Available and Achievable Capacities from Different Producers in Zimbabwe in 2021 (MW)**

Source	*Energy source*	*Installed capacity (MW)*	*Available capacity (MW)*	*Achievable capacity (MW)*
Kariba South hydropower plant	Hydropower	1,050.0	1,050.0	1,050.0
Hwange thermal power plant	Coal	920.0	750.0	715.0
Small thermal plants (Munyati, Bulawayo, Harare)	Coal	329.0	80.0	45.0
IPPs	Small hydropower	30.6	30.6	30.6
	Solar PV	10.0	10.0	10.0
	Bagasse	88.0	N/A	N/A
Community-owned (off-grid)	Hydropower	0.4	0.4	0.4
	Solar PV	3.0	3.0	3.0
Total		**2,431.0**	**1,924.0**	**1,854.0**

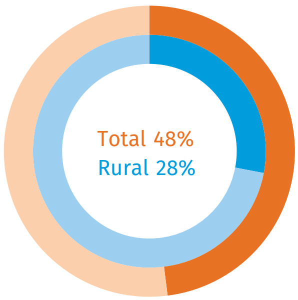
Source: AfDB,[6] MoEPD[8]

The capacity of IPPs from photovoltaic (PV) solar power plants includes the 2.5 MW Riverside power plant by Nyangani Renewable Energy Private Limited and the 2.5 MW Centragrid power plant. The Riverside power plant, commissioned in January 2018 to supply the national grid, is the first phase of the 10 MW project planned for a site in Mutoko, Mashonaland East Province of Zimbabwe.[12] The Centragrid plant is located in Nyabira, Mashonaland West Province of Zimbabwe, and was commissioned in October 2019.[13] Three planned solar power plants owned by ZPC, with 100 MW of capacity each, are yet to reach financial closure.[8]

The country imports electricity from the regional utilities to cover up for the local supply deficit: 50 MW of firm capacity from the Cahora Bassa Hydroelectric (HCB) of Mozambique and 50 MW of firm capacity from Eskom of South Africa. Variable imports operate on the Day-Ahead Market, managed by the Southern African Power Pool (SAPP) Coordination Centre. Zimbabwe has no firm capacity exports due to limited local generation capacity.[6]

According to the Zimbabwe National Statistics Agency (ZIMSTAT), the country's electrification rate was at 48 per cent in 2017 (Figure 3). Twenty-eight per cent of rural population had access to electricity and the urban electrification rate stood at 86 per cent.[14] Approximately 80–90 per cent of the rural population depend on wood fuel and kerosene for cooking and lighting according to the Zimbabwe Infrastructure Report published by the Africa Development Bank (AfDB) in 2019.[6] Food processing tasks, such as grain milling, are usually carried out with a diesel-powered system, with a few now using electricity. Although Zimbabwe is endowed with an abundance of renewable energy resources such as solar power, wind power, biomass and SHP, including run-of-river plants and inland dams, these are still not fully utilized.

Figure 3. **Electrification Rates in Zimbabwe in 2017 (%)**



Source: ZIMSTAT[14]

The energy sector in Zimbabwe is overseen by the Ministry of Energy and Power Development (MoEPD). Below MoEPD is the Zimbabwe Energy Regulatory Authority (ZERA), which ensures fairness in the sector. ZERA oversees the operations of the Zimbabwe Electricity Supply Authority (ZESA) Holdings Private Limited Subsidiaries, the oil companies and IPPs. The Zimbabwe Electricity Transmission and Distribution Company (ZETDC) and ZPC are subsidiary companies of ZESA Holdings, and the oil companies include both public and private companies. In addition, ZESA ensures fair tariffs and the quality of the provision of other services to the consumers.[7]

The national electricity grid has capacities ranging from 11 kV for low voltage to 33 kV, 36 kV, 66 kV, 360 kV and 420 kV for interconnections with the region. The grid is interconnected to the Southern African Development Community (SADC) region with the Zimbabwe grid being central. The operations of the regional grid are coordinated by the SAPP Coordination Centre, which is based in Zimbabwe.

To ensure the implementation of the country's pricing policy, Zimbabwe established the ZERA in 2012 in line with the SADC regional requirements. ZERA, in consultation with MoEPD, is responsible for the designing of the electricity pricing policy, as well as analyzing and approving tariff applications by both the state utility and the IPPs. ZERA may review tariffs for licensed operators when they apply, according to their needs. According to information recorded in the Zimbabwe Infrastructure Report of 2019 prepared by the AfDB, ZERA last reviewed the standard tariff schedule for the electricity sector in January 2013. An application for a 49 per cent tariff review was submitted by ZETDC as a bid to move from 0.099 USD/kWh to 0.147 USD/ kWh. However, after stakeholder consultations, it was resolved to keep the tariff at 0.099 USD/kWh.[6]

The tariff structure differentiates between domestic users who pay fixed charges and those who pay as per consumption levels. There is a lifeline support offered by subsidizing the first 50 kWh per month for all residents at approximately 0.02 USD/kWh. Low-demand non-residential consumers are charged both a fixed rate and flat variable rates depending on their consumption and metering system (Table 3). For comparison, the average electricity tariff in the SADC region ranges between 0.03 and 0.17 USD/kWh.[6]

Table 3. **Average Electricity Prices in Zimbabwe (USD/kWh)**

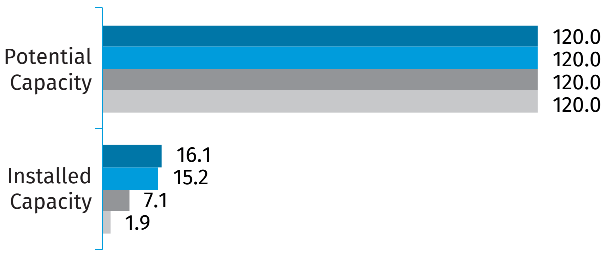
Sector	*2015*	*2016*	*2017*	*2018*
Industrial	0.0897	0.0940	0.0849	0.0804
Domestic	0.0980	0.0998	0.0996	0.0994
Overall approved	0.0991	0.1004	0.0966	0.0961
Average tariff	0.0986	0.0986	0.0986	0.0986

Source: AfDB[6]

SMALL HYDROPOWER SECTOR OVERVIEW

In Zimbabwe, SHP is defined as hydropower with an installed capacity of up to 30 MW.[4,15] Based on the up to 10 MW definition, Zimbabwe had an installed SHP capacity of 16.1 MW (grid-connected and off-grid) as of December 2020.[7] The total potential capacity for SHP up to 10 MW is estimated at 120 MW according to MoEPD, which includes both reservoir and run-of-river sites.[16] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the potential capacity remained the same, whereas the installed capacity increased by 6 per cent (Figure 4). The total installed capacity for SHP up to 30 MW in Zimbabwe is 31.35 MW, which includes a 15.25 MW power plant not included under the up to 10 MW definition of SHP.[9,16,17]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Zimbabwe (MW)**



Source: MoEPD,[16] *WSHPDR 2019*,[17] *WSHPDR 2013*,[18] *WSHPDR 2016*[19]

Note: Data are for SHP up to 10 MW.

The off-grid systems, which are community-owned and have been sponsored by the non-governmental organizations Practical Action and Oxfarm, reached an operational capacity of approximately 400 kW by 2017.[18] The grid-connected SHP plants are privately owned by IPPs, which include Nyangani Renewable Energy (NRE), Kupinga Renewable Energy (KRE) and Bonemarrow Investments. These have separate Power Purchase Agreements (PPAs) with ZETDC as the sole owner and operator of the national grid (Table 4).[7,8]

A number of SHP projects are currently under development (Table 5).

Table 4. **List of Operational Small Hydropower Plants in Zimbabwe**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Pungwe B	Nyanga	15.3	Run-of-river	Nyangani Renewable Energy (NRE)	2014
Pungwe C	Nyanga	3.8	Run-of-river	Nyangani Renewable Energy (NRE)	2016
Pungwe A	Nyanga	2.8	Run-of-river	Nyangani Renewable Energy (NRE)	2011
Hauna	Nyanga	2.3	Run-of-river	Nyangani Renewable Energy (NRE)	2017
Duru	Nyanga	2.2	Run-of-river	Nyangani Renewable Energy (NRE)	2010
Tsanga B	Nyanga	2.1	Run-of-river	Nyangani Renewable Energy (NRE)	2018
Kupinga	Nyanga	1.6	Run-of-river	Kupinga Renewable Energy (KRE)	2017
Nyamingura	Nyanga	1.1	Run-of-river	Nyangani Renewable Energy (NRE)	2010
Claremont	Nyanga	0.3	Run-of-river	Bonemarrow Investment	2017

Source: ZERA[7]

Table 5. **List of Ongoing Small Hydropower Projects in Zimbabwe**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Developer*	*Stage of development*
Tsanga A	Nyanga	2.7	Run-of-river	Nyangani Renewable Energy (NRE)	Construction
Tsanga C	Nyanga	2.2	Run-of-river	Nyangani Renewable Energy (NRE)	Construction
Rusitu	Nyanga	1.0	Run-of-river	Rusitu Power Cooperation	Construction
Great Zimbabwe Hydro Power Plant	Masvingo	5.0	Inland dam	Great Zimbabwe Hydro Private Limited	Licensed

Source: ZERA[7]

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

Funding is required to update pre-feasibility and feasibility studies on several sites especially the inland dam sites. Partnerships and investors for the sites are welcome to boost electricity supply security in the country. Sites will be made available to potential investors and partners (Table 6).[8]

Table 6. **List of Selected Small Hydropower Projects Available for Development**

Name	*Location*	*Potential capacity (MW)*	*Type of site (new/refurbishment)*
Tokwe Mukosi	Mwenezi	15.0	Inland dam, new
Orsbone	Nyanga	3.0	Inland dam, new
Odzani	Odzi	2.4	Run-of-river, new
Nyahonde	Nyanga	1.7	Run-of-river, new
Immaculate Technology	Masvingo	1.6	Inland dam, new

Source: ZERA[7]

Note: List compiled in 2021.

RENEWABLE ENERGY POLICY

Since the establishment of the Electricity Act of 2002, IPPs have been allowed to develop power generation plants.[20] There is also a National Energy Policy (NEP) that was launched in 2012, which summarizes the potential of SHP in the country and encourages the increased use of renewable energy sources in the country's energy supply mix.[21] The NEP is also supported by the country's economic blueprint, the Zimbabwe Agenda for Sustainable Socio-Economic Transformation (ZIMASSET). The ZIMASSET was succeeded by the Transitional Stabilization Programme (TSP), which was launched in 2018 and ran from October 2018 to December 2020. The focal areas of the TSP included: stabilization of the macro-economy and the financial sector; introduction of necessary policy and institutional reforms to transform to a private sector–led economy; and launch of 'quick-wins' to stimulate growth.[21] The TSP was underpinned by Vision 2030 Towards an Upper Middle-Income Country. Vision 2030 will be implemented in two phases with the first National Development Strategy launched in 2020 to run from 2021 until 2025.[22] The above documents do not elaborate much on the development of renewable energy sources, such as SHP. The country now has a National Renewable Energy Policy (REP) in place which was launched in 2019.[17] The REP promotes investment in renewable energy sources, including SHP as well as both on- and off-grid projects.[17]

Zimbabwe, through the Ministry of Environment, Water and Climate (MEWC), has prepared and submitted the Third National Communications to the United Nations Convention on

Climate Change (UNFCCC). A Climate Change Response Strategy was developed for the country, as well as a Climate Policy.[23] The country also ratified the Paris Agreement and has submitted Nationally Determined Contributions (NDCs), with hydropower development as one of the measures aimed at the mitigation of, and adaptation to, climate change effects. It is also worth noting that future hydropower development in Zimbabwe will need to ensure robustness and capability for survival against climate change effects.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

There is no particular regulation or legislation targeting SHP development in Zimbabwe. The sector is governed by the same laws that apply to fossil fuels and other renewable energy sources. The principal law is the Electricity Act of 2002 supported by the Energy Regulatory Act of 2011. There are also the Electricity Licensing Regulations of 2008 amended by Statutory Instrument 55 of 2015. In 2018 the net-metering regulations also came into force.[21]

COST OF SMALL HYDROPOWER DEVELOPMENT

SHP projects in Zimbabwe have been developed mostly by private players and on a case-by-case basis. Therefore, the findings of feasibility studies as well as data on development costs are owned by the private developers.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The Infrastructure Development Bank of Zimbabwe (IDBZ) in 2019 called for a bid for consultancy to carry out feasibility studies for the Odzani power plant on the Odzani River.[24] However, there is no record of the finalization of the procurement process. ZERA developed some feed-in-tariffs (FITs), which have yet to be approved by the Government.[17] The REP has a policy statement for all SHP projects within a capacity of 30 MW to be procured through FITs once they are approved.[17]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Even though hydropower development is listed among the mitigation solutions for climate change, at the same time the sector is also at risk of being affected negatively by changes in rainfall patterns. Some negative effects have already been witnessed, as reduced water levels affected power generation at the Kariba hydropower plant during certain seasons over recent years.[25] Some climate records in the country have demonstrated that Zimbabwe is already experiencing the effects of climate change, especially rainfall variability. The induced water stress threatens to reduce the runoff necessary to sustain SHP plants, especially the run-of-river ones.[27]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Policies and regulations have a bearing on the rate of SHP development in the country. From 2011, when ZERA came into existence, followed by the NEP, the trend of SHP development has been on the rise. A greater impact is expected with the REP in place and a procurement framework being worked on by MoEPD.[8]

The following are the main barriers to SHP development in Zimbabwe:

- The effects of extreme weather conditions;
- Lack of FITs and standard procurement methods: currently tariffs are negotiated on a case-by-case basis;
- High costs of local funding: local banks offer short-term loans at high interest rates;
- Difficulties in accessing foreign funding by most potential developers: very few IPPs have managed to reach financial closure for an SHP project;
- Lack of funding for feasibility studies to ensure the bankability of projects: most project sites fail to attract funding due to the unavailability of bankable feasibility studies;
- No locally manufactured equipment: all turbines, generators and control equipment are imported.

The development of SHP in Zimbabwe is expected to be further enabled by the REP and the net-metering regulations which are now in place.[7]

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1.2. Middle Africa

Countries: Angola, Cameroon, Central African Republic, Congo, Democratic Republic of the Congo, Equatorial Guinea, Gabon, Sao Tome and Principe

INTRODUCTION TO THE REGION

Middle Africa is well-supplied with water resources and hydropower is the primary source of electricity generation for most countries in the region. The exceptions include Sao Tome and Principe and Congo, which rely heavily on thermal power, and Gabon, which is well-supplied with domestic fossil fuel resources and where thermal power forms the mainstay of electricity generation along with hydropower. In other countries in the region, thermal power plays a supplementary role, providing a very significant share of installed capacity but contributing only a small share of total electricity generation. Renewable energy resources other than hydropower are represented mainly by solar power and bioenergy, although their contribution to electricity generation is minor.

In many countries in the region, nationwide electricity access stands at less than 50 per cent, with very significant disparities between urban and rural areas across the entire region apart from Sao Tome and Principe. The lack of electricity access in such countries as Angola and the Democratic Republic of the Congo, both major electricity producers, highlights the insuf-ficient connectivity and reliability of the transmission and distribution networks, with transmission and distribution losses in some countries reaching 40 per cent of total generation. In this context, distributed power generation could potentially have a positive impact on regional rates of electricity access.

An overview of the electricity sectors of the countries in the region is provided in Table 1.

Table 1. **Overview of Middle Africa**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Angola	31	46	7	5,931	17,777	3,729	12,562
Cameroon	27	65	25	1,547	7,006	950	5,230
Central African Republic	5	32	16	41	157	19	148
Congo	6	48	13	794	2,988	228	872
Democratic Republic of the Congo	90	19	1	2,802	9,990	2,750	9,855
Equatorial Guinea	1	67	7	406	479	127	448
Gabon	2	93	63	632	2,332	332	981
Sao Tome and Principe	0.2	76	71	39	110	2	5
Total	-	-	-	**12,193**	-	**8,137**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

In the Middle Africa region, the definition small hydropower (SHP) as hydropower plants with an installed capacity of up to 10 MW is adhered to by Angola, the Central African Republic, the Democratic Republic of the Congo, and Sao Tome and Principe. Additionally, in Angola the up to 50 MW definition is used on occasion. In Cameroon, SHP is defined as plants up to 5 MW in the context of rural electrification programmes. No official definition of SHP exists in Congo, Equatorial Guinea and Gabon.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Middle Africa (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Angola	Up to 10 MW	46.1	600.0	46.1	600.0
Cameroon	Up to 5 MW	1.5	N/A	1.5	970.0
Central African Republic	Up to 10 MW	18.8	41.0	18.8	41.0
Congo	N/A	N/A	N/A	0.0	70.5
Democratic Republic of the Congo	Up to 10 MW	56.0	100.9	56.0	100.9
Equatorial Guinea	N/A	N/A	N/A	7.5	31.9
Gabon	N/A	N/A	N/A	6.0	518.1
Sao Tome and Principe	Up to 10 MW	1.9	63.8	1.9	63.8
Total	-	-	-	**137.8**	**2,396.2**

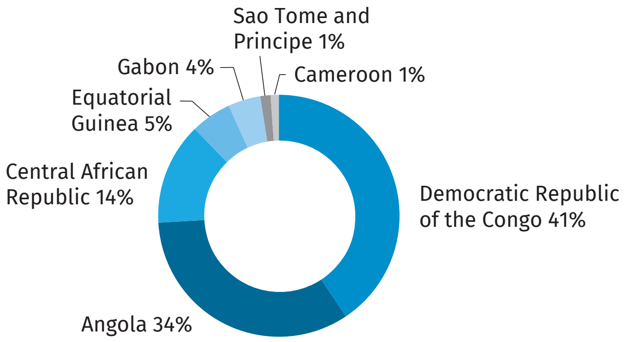
Source: *WSHPDR 2022*[1]

The total installed capacity of SHP up to 10 MW in Middle Africa is 137.8 MW, while the potential capacity is estimated at 2,396.2 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has increased by 21 per cent, largely due to more accurate data becoming available on the total capacity of SHP plants in Angola. Small increases in installed capacity were also observed in Cameroon and Gabon, while in the rest of the region installed SHP capacity either remained the same or actually declined. The estimate of potential capacity increased by 29 per cent, largely due to the availability of new data on the technical SHP potential in Gabon.

SHP plays a particularly important role in the Central African Republic and Sao Tome and Principe, where it accounts for 100 per cent of installed hydropower capacity. In other countries in the Middle Africa region, the hydropower sector is dominated by large-scale plants and the contribution of SHP to the generation of electricity is relatively small. Recent activities in the SHP sector in the region have mainly focused on the rehabilitation of existing SHP plants, although one new plant was commissioned in 2021 in Cameroon.

The national share of regional installed SHP capacity by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

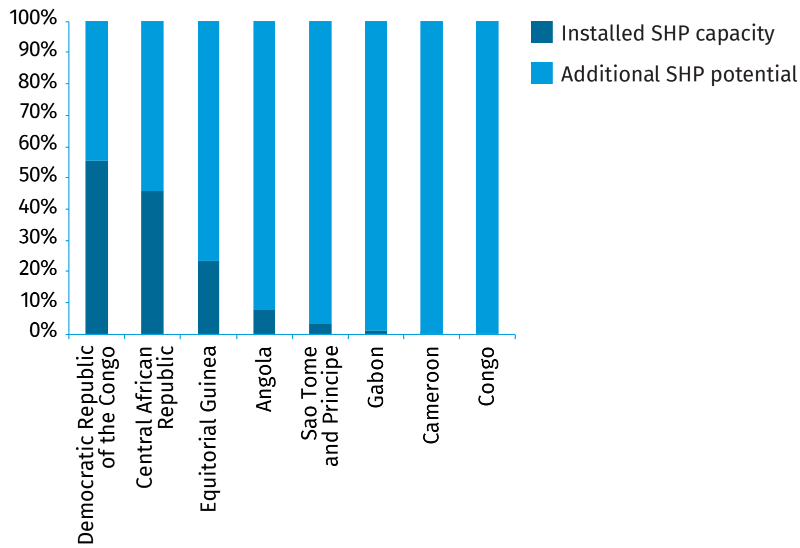
Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Middle Africa (%)**



Source: *WSHPDR 2022*[1]

Note: Congo not included due to a lack of SHP capacity.

Figure 2. **Utilized Small Hydropower Potential up to 10 MW by Country in Middle Africa (%)**



Source: *WSHPDR 2022*[1]

The installed capacity of SHP up to 10 MW in **Angola** is 46.1 MW, while the potential capacity is estimated at 600 MW, indicating that nearly 8 per cent has been developed. The identified potential is contained in 100 different sites identified in 2015 as part of the country's Energy Strategy to 2025. Of these, at least six have been selected for priority investment by 2025.

In **Cameroon**, the installed capacity of SHP up to 10 MW is 1.5 MW, accounted for by a single SHP plant. The country's SHP potential is estimated at 970 MW, indicating that less than 1 per cent has been developed, but no detailed assessment of existing sites is available. One SHP project with an installed capacity of 2.9 MW is under development, but its commissioning was stopped due to the civil war.

The **Central African Republic** has an installed capacity of 18.8 MW for SHP of up to 10 MW, while estimated potential capacity is 41 MW, indicating that 46 per cent has been developed. The country has two SHP plants in operation, while construction of a third plant with a capacity of 10 MW was suspended due to political instability, and the plant is in need of rehabilitation.

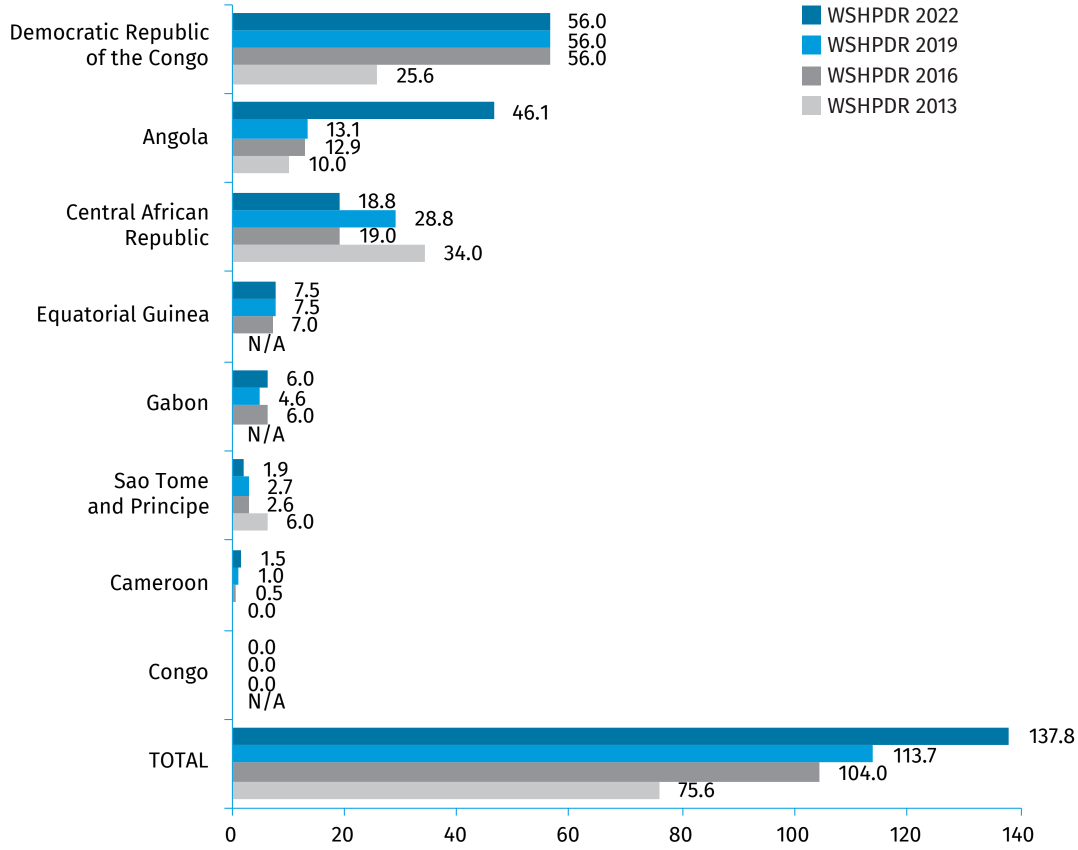
At least 15 sites suitable for SHP development have been identified in the country, and the construction of one additional SHP project is ongoing as of 2021.

There is no installed SHP capacity in **Congo**. The potential capacity for SHP has been most recently estimated at 75 MW and is entirely undeveloped. At least 27 potential SHP sites have been identified throughout the country, with capacities ranging between 6 kW and 10 MW. Several feasibility studies of potential SHP sites supported by various international institutions have been recently completed, and a number of additional studies were either ongoing or in the planning stages as of 2021.

In **the Democratic Republic of the Congo**, the installed capacity for SHP of up to 10 MW is 56 MW, while potential capacity is estimated at 100.9 MW, indicating that 55 per cent has been developed. No new SHP construction has taken place in the country in the last several years, although five new SHP projects were in the planning stages as of 2021.

The installed capacity for SHP of up to 10 MW in **Equatorial Guinea** is 7.5 MW, while potential capacity is estimated at 31.9 MW, indicating that nearly 24 per cent has been developed. There are three operational SHP plants in the country, with the largest one, the 3.8 MW Riaba SHP plant, operating at only a fraction of its installed capacity and in need of extensive repairs and upgrades. At least 36 potential SHP sites have been identified in the country and detailed evaluations of the sites are ongoing.

Figure 3. **Change in Installed Capacity of Small Hydropower up to 10 MW from *WSHPDR 2013* to *WSHPDR 2022* by Country in Middle Africa (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

Gabon has an installed capacity of 6 MW for SHP of up to 10 MW, provided by three SHP plants. The potential capacity is estimated at 518.1 MW, indicating that approximately 1 per cent has been developed. Recent activity in the SHP sector in the country has been limited to the refurbishment of existing plants and updated studies of the country's SHP potential.

In **Sao Tome and Principe**, the installed capacity for SHP up to 10 MW is 1.9 MW while potential is estimated at 63.8 MW, indicating that approximately 3 per cent has been developed. There is only one operational SHP plant in the country, while three others have been decommissioned and are in need of extensive refurbishment or reconstruction. Thirty-four potential SHP sites have been identified in the country, but no new SHP projects are currently planned.

Changes in the installed capacities of SHP up to 10 MW in the countries in the region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Climate Change and Small Hydropower

Countries in the Zambezi River basin, which includes Angola, have already experienced climate change, especially rainfall variability. The projected continuous rise in evaporation and evapotranspiration due to increased temperatures could spur higher water stress in the region. However, the impacts on runoff are yet uncertain.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers to SHP development in **Angola** are the lack of stability in regulations governing asset ownership, the awarding and return of concessions, land acquisition and power purchase agreements, as well as a general lack of experience with investor relations, public-partner partnerships and Build-Operate-Transfer schemes. Additionally, the country has limited technical expertise in the SHP sector, with large hydropower taking precedence in national development.
At the same time, the large untapped SHP potential in the country and favourable topography, a multitude of identified SHP sites offer many opportunities for investment in the sector, particularly in light of increasing access to international financing.

Obstacles to SHP development in **Cameroon** include a lack of detailed assessments of SHP potential, lack of financing, unreliable infrastructure and an absence of local capacity for manufacturing electromechanical equipment. Enablers include the very significant untapped SHP potential in the country, increasing momentum in favour of renewable energy resource development and the strong need for rural electrification.

SHP development in the **Central African Republic** is hampered by a lack of incentives, monopolization of the electricity sector, which discourages investors, lack of technical capacity, limited financial resources and political unrest. However, the topography and hydrology of the country are overall favourable for SHP and projects can be undertaken with the support of a number of international institutions and financing mechanisms that have a presence in the country.

In **Congo**, barriers to SHP development include a lack of incentives and technical capacity, high cost of electricity transmission, gaps in the legal and regulatory framework regarding SHP, and expected decreases in river flow during the dry season, which could undermine the viability of run-of-river plants. The main enablers for SHP development in the country are the untapped SHP potential and a relatively liberalized electricity market.

The development of SHP in **the Democratic Republic of the Congo** is held back by the weak enforcement of the institutional and regulatory framework for private investment in the energy sector, high cost of development, lack of affordable financial mechanisms, lack of a renewable energy policy and focus on large-scale generation. The liberalization law passed in 2014 could act as an incentive for SHP development if properly enforced, allowing the country to take advantage of its substantial untapped SHP potential.

The main barrier to SHP development in **Equatorial Guinea** is the high cost of SHP relative to other energy sources, in particular subsidized fossil fuels, as well as lack of incentives for renewable energy and lack of detailed data on potential sites. The main enablers are the remaining untapped SHP potential and interest in SHP development in the country on the part of international development institutions.

Barriers to SHP development in **Gabon** include inadequate infrastructure, lack of local expertise, high costs and excessive bureaucratization. However, the regulatory environment for private investment is expected to improve and the country is aiming to transition from an oil-based economy to one reliant on renewable energy. The SHP sector is expected to benefit from the system-scale approach outlined in the Government's planned changes to the licensing process for hydropower projects, and be able to take advantage of the recently-identified and large SHP potential.

The main barrier to SHP development in **Sao Tome and Principe** is the lack of an institutional framework and policy mechanisms that would enable the realization of the country's identified SHP potential. However, SHP is seen as a promising solution for extending electricity access to the country's rural and remote areas, as well as decreasing its heavy reliance on fossil fuels.

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Angola

Pedro Manso, Mathieu Barnoud & Lara Carimo, MHYD water & energy solutions sàrl

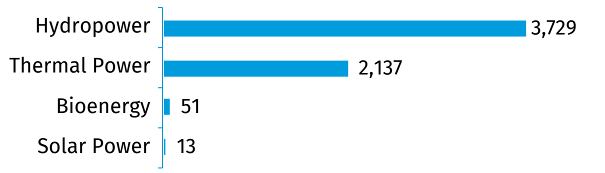
KEY FACTS

Population	31,127,674 (est. 2020)[1]
Area	1,246,700 km^2 [2]
Topography	The topography of Angola is characterized by a narrow coastal plain in the west from which rise broad tablelands lying at over 1,000 metres above sea level, a high plateau in the centre and mountain ranges to the south reaching up to 2,400 metres. The highest point is Mount Moco, at 2,620 metres above sea level, in the Huambo Province.[3,4]
Climate	The climate in Angola is tropical, with a warm rainy season from September to May and a cooler dry season from June to August. The country is divided into two climatic regions, the coast and interior. The annual average temperature ranges between a minimum of 17 °C and a maximum of 27 °C.[2]
Climate Change	Based on historical data, the mean temperature increased by 1.5 °C from 1960 to 2016. The frequency of hot days increased, while cold days decreased in the period of 1960–2003. The mean annual precipitation has been decreasing, at an average rate of 2 mm per decade. A greater decrease in late summer precipitation and increase in precipitation variability in the central-south transition area have also been observed. Climate models have predicted a continuous increase in temperature. From 2040 to 2059, an increase of 2 °C is projected, with rapid warming to take place in the interior and eastern parts of the country. There is a wide range of predictions for the change in precipitation across the country, with the predominant prediction indicating a decrease of mean annual precipitation by almost 14 mm (CMIP5 projections, RCP 8.5, Ensemble). However, the annual maximum 5-day rainfall for a 25-year period return is expected to rise by 15 mm.[5,6]
Rain Pattern	The cooler months in Angola (June–August) are very dry, with almost no rainfall. The wet season (October–April) receives between 100 mm and 250 mm of rainfall per month. The total rainfall decreases from north-east towards south and the western coast. Annual rainfall averages 984 mm.[2,4,5]
Hydrology	Most of the rivers in Angola rise in the central mountains, draining in all directions. The perennial rivers are concentrated in the north and centre, while in the south there are only three perennial rivers: the Cunene, Cuando and Cubango. Of the many rivers draining into the Atlantic Ocean, the most important ones are the Cuanza and Cunene. Other major rivers include the Cuango, draining northwards to the Congo River system, as well as the Cuando and Cubango Rivers, draining south-eastwards to the Okavango Delta in Botswana. There are no sizable natural lakes in Angola.[4,7]

ELECTRICITY SECTOR OVERVIEW

Electricity generation in Angola in 2019 was 17,777 GWh. Approximately 71 per cent of this total was from hydropower, almost 28 per cent was produced by oil- and gas-fired thermal power plants and approximately 1 per cent was from bioenergy and solar power (Figure 1).[8]

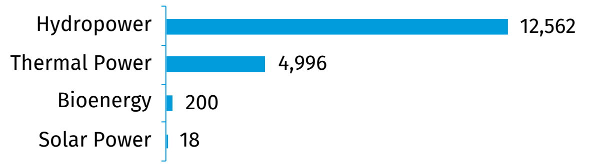
Figure 1. **Annual Electricity Generation by Source in Angola in 2019 (GWh)**



Source: IRENA[8]

In 2020, the total installed capacity of Angola reached 5,931 MW, of which 63 per cent was from hydropower, 36 per cent from thermal power and another 1 per cent from bioenergy and solar power plants (Figure 2).[8] The increase in capacity in recent years mainly originated from the hydropower plants of Cambambe 2 and Laúca, with 960 MW and 1,670 MW (five units out of six already commissioned), respectively, and the thermal combined-cycle power plant of Soyo, with 500 MW.[9]

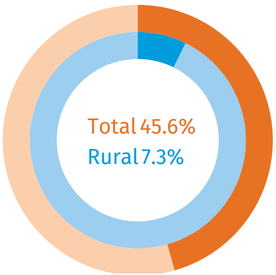
Figure 2. **Installed Electricity Capacity by Source in Angola in 2020 (MW)**



Source: IRENA[8]

In 2019, 45.6 per cent of the population of Angola had access to electricity, with almost 74 per cent access in urban areas, while the most recent data from the World Bank indicate that only 7.3 per cent of rural areas had access to electricity in 2018 (Figure 3).[10] The rate of electrification is not homogeneous throughout the country.[11] The National Company for the Distribution of Electricity (ENDE) had a total of 1,585,000 clients in 2018 divided into residential, services and industrial consumers. For comparison, in 2015 ENDE served 1,275,468 clients. Of the customers served by ENDE, approximately 200,000 were provided with electricity through prepaid meters.[9,12]

Figure 3. **Electrification Rate in Angola in 2018 (%)**



Source: World Bank[10]

The electricity consumption in Angola reached 11.6 TWh, in 2020.[13] According to United Nations Statistics Division (UNSD) data, between 2014 and 2018 electricity consumption increased by 24 per cent. In 2018, households accounted for 59 per cent of total consumption and losses amounted to 12 per cent.[14] With uneven electrification, the consumption is concentrated in the northern region.[4]

The Regulatory Institute for Electricity and Water (IRSEA) was established in 2016 by Decree No. 59/16, transferring all rights and obligations from the Regulatory Institute for Electricity Sector (IRSE). The role of IRSEA is to regulate activities of production, transport, distribution, sale and use of electricity in the Public Electricity System (SEP) as well as to regulate the commercial relationship between SEP and agents that are not linked to it.[15] The design principles of this established model aim to develop a competitive process for both public and private generation and to establish an Independent Transmission Operator, which will also act as a single buyer for all electricity generated in the SEP.[4]

The electricity tariff categories are approved by Presidential Decrees No. 4/11 and No. 178/20 and defined by Executive Decree No. 122/19, which provides the basis for the calculation of tariffs. The rates are composed of two components, one based on the power and the other one based on consumption. The low voltage tariff rates are within the range of 2.46–14.74 AOA/kWh (0.004–0.026 USD/kWh), medium voltage rates are 9.61–11.54 AOA/kWh (0.017–0.020 USD/kWh) and the high voltage rate is 7.31 AOA/kWh (0.013 USD/kWh) (Table 1).[15]

Table 1. **Electricity Tariffs in Angola**

Category	*Power component (AOA (USD) per unit)*	*Consumption component (AOA (USD) per kWh)*
Low voltage		
Social household I	0	2.46 (0.004)
Social household II	80.00 (0.140)	6.41 (0.011)
Street lighting	45.00 (0.080) x pc	7.05 (0.012)
Single-phase household	90.00 (0.160) x pc	10.89 (0.019)
Three-phase household	100.00 (0.180) x pc	14.74 (0.026)
Commerce and services	100.00 (0.180) x pc	14.74 (0.026)
Industry	100.00 (0.180) x pc	12.82 (0.023)
Medium voltage		
Commerce and services	160.00 (0.280) x P	11.54 (0.020)
Industry	160.00 (0.280) x P	9.61 (0.017)
High voltage		
Industry	115.00 (0.200) x P	7.31 (0.013)
Distributors	115.00 (0.200) x P	7.31 (0.013)

Source: IRSEA[15]

Note: pc — contracted power (kVA), P — the maximum point of 15 consecutive minutes (kW).

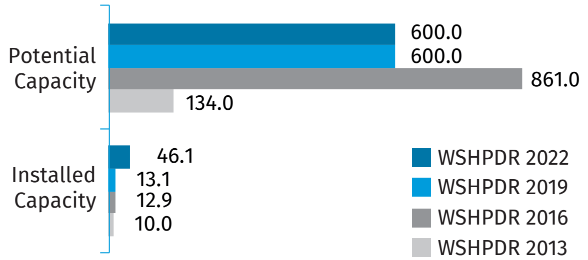
Presidential Decree No. 256/11, defining the National Policy and Strategy for Energy Security, established goals for the electricity sector until 2025.[16] For its implementation, short-term plans were defined. The plan for 2013–2017 fell short of what was initially planned. The following, 2018–2022 action plan has three development programmes and subprogrammes, which include the expansion of electricity access in urban areas, municipalities and rural areas; the optimization and sustainable management of the electricity sector; and private participation in the production and distribution of electricity.[4,11]

SMALL HYDROPOWER SECTOR OVERVIEW

The common definition of small hydropower (SHP) in Angola is up to 10 MW, although plants of up to 50 MW are often referred to as SHP as opposed to large hydropower of up to 1,000 MW and 2,000 MW. The installed capacity of SHP in Angola amounts to 46.1 MW (Table 2), indicating a significant increase since the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 4). The estimated potential capacity, as identified by the Angola Energy Strategy 2025 of the Ministry of Energy and Water (MINEA), is 600 MW from 100 different sites.[18] A list of known planned SHP projects is presented in Table 3.

Figure 4 presents a summary of SHP data made available by the National Water Resources Information System (INRH) and the Public Electricity Production Company (PRODEL-EP).[19,20] However, this list has not been updated since the publication of the *WSHPDR 2019*, providing the same estimate of SHP installed capacity of 13.1 MW as reported in the previous edition. Additionally, it is also known that ENDE manages SHP plants of up to 5 MW each, with a total installed capacity of 33 MW.[11] The sum of these two figures gives the installed capacity of 46.1 MW. The significant increase in SHP installed capacity since the previous edition of the report may be related to the uneven dispersion of information, in addition to the new investments made in this sector.

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Angola (MW)**



Source: *WSHPDR 2019*,[4] Gesto,[11] National Energy Atlas,[18] INRH,[19] PRODEL-EP,[20] *WSHPDR 2013*,[21] *WSHPDR 2016*[22]

Note: Data for SHP up to 10 MW.

Angola has a significant hydropower potential. However, the development and rehabilitation of power plants have not succeeded in keeping the supply in line with the expanding demand. The technical potential is estimated at approximately 80 TWh/year and the economic potential is 72 TWh/year (18 GW). Information on SHP potential in the country was assembled in the Atlas of the Hydropower Resource.[15,18,23]

Table 2. **List of Selected Operational Small Hydropower Plants in Angola (up to 50 MW)**

Name	*Location*	*Capacity (MW)*
Lomaum	Benguela	50.0
Matala	Huíla	40.8
Mabubas	Uíge	25.6
Chicapa	Lunda Sul Province	16.0
Biópio	Benguela	15.2
Chiumbe Dala	Lunda Sul Province	12.0
Cunje II	Bié	7.5
Luquixe II	Uíge	2.1
Cunje I	Bié	1.6
Rápidos do rio lifune	Nambuangongo, Muxaluando	1.1
Cuando	Huambo	1.0

Source: INRH,[19] PRODEL-EP[20]

Table 3. **List of Selected Planned Small Hydropower Projects in Angola**

Name	*Location*	*Capacity (MW)*	*Stage of development*
Luachimo	Lunda Norte	8.4	Works ongoing
Luquixi	Uíge	2.1	Rehabilitation

Source: INRH,[19] PRODEL-EP[20]

The national plan for the electricity sector up to 2025 intends to develop new SHP plants for achieving the renewable energy installed capacity targets and to promote electrification of isolated rural areas.[15] From the 100 potential locations identified for SHP by MINEA, seven were selected with potential to supply nine municipal townships through isolated systems, including the Cutato, Quedas de Kaquina and M'Pupa Rapids SHP plants.[15,24,27] The 2025 Angola Power Sector Long-Term Vision lists the priority investments for the 2018–2025 horizon, with several potential SHP projects identified for priority investment (Table 4). Other potential sites not identified in the long-term vision also remain available for SHP development (Table 5).

Table 4. **Small Hydropower Sites Prioritized for Investment for the 2018–2025 Horizon**

Name	*Capacity (MW)*	*Total Investment (USD million)*
Andulo	0.5	3.1
Kuito 2	0.6	3.7
Kuando	2.0	12.4
Liapeca	4.0	24.8
M'Bridge	4.6	28.4
Other ongrid	48.0	240.7
Cuemba (off-grid)	0.5	3.1
Other off-grid	28.3	220.5

Source: MINEA[17]

Table 5. **List of Small Hydropower Projects Available for Investment**

Name	*Location*	*Potential capacity (MW)*	*Type of site (new/refurbishment)*
F.Caála	Balombo	1.22	New
Balombo	Balombo	9.60	New
Freitas morna	Ambriz, Bela vista	8.00	New
Rápidos do rio lifune	Nambuangongo, Muxaluando	1.06	New
Bocoio	Bocoio	2.58	New

Source: National Energy Atlas[18]

RENEWABLE ENERGY POLICY

The Electricity Sector Transformation Programme (PTSE) is a result of the National Policy and Strategy for Energy Security and is divided into four implementation phases, the latest being over the period 2021–2025. It proposed a power sector reform involving three different measures: diagnosis, mobilization and change management; electric sector restructuring; and operational and functional improvement of public companies, implemented from 2012 to 2016. The studies conducted by this programme also recommend the incentivized participation of the private sector in renewable energy development in rural areas via feed-in tariffs and a partial liberalization of distribution systems and the energy sector, including full participation of independent power producers (IPPs) and the improvement of the energy mix.[4,25,28] This is proposed to be implemented until 2025.[28] Recently, in 2021, a law was established for independent energy production.

The restructuring of the electricity sector began in 1996, with the publication of the General Electricity Law 14-A/96, which, together with the Energy Security Policy of 2011, paved the way for the publication of new regulations essential for the energy market, and the amendment of the General Electricity Law, Law No. 27/15. Laws and Regulations published to establish the legal regime for the exercise of the activities of generation, distribution and supply of electricity, including by IPPs, are:

- General Electricity Law No. 14-A/96;
- General Electricity Law No. 27/15;
- Electricity Production, Transport, Distribution and Commercialization Activities Regulation, Presidential Decree No. 76/21;
- Electricity Supply Regulation, Presidential Decree No. 27/01;
- Regulation of Independent Electric Energy Production, approved by Presidential Decree No. 43/21;
- Regulation on the licensing of facilities for the use of electricity, Presidential Decree No. 40/04;
- Regulation of Electricity Production, Transport and Distribution facilities, Presidential Decree No. 41/04;
- Private investment law, Presidential Decree No. 10/21.[15,26]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

In early 2021, some changes were made in the regulatory framework of Angola which encourage the renewable energy sector, namely Decrees No. 76/21 and 43/21.[15] Furthermore, the Government of Angola has a specific decree for the model of concession contracts and the purchase and sale of electricity for SHP projects (No. 82/10). This is a legal instrument for public-private partnerships, aiming at the launch of the public tender for SHP and associated transport systems, as part of MINEA's intention to promote access to electricity in the isolated locations of the country.

The high-potential SHP sites identified under the Angola Energy Strategy 2025 programme are to be further studied. These feasibility studies aim to launch tenders for a total of 100 MW in mini- and small-scale hydropower projects.[17]

COST OF SMALL HYDROPOWER DEVELOPMENT

The mean cost of SHP installed in Angola is estimated at approximately 6.2 million USD/MW (Table 6), with the values being based on the Angola Energy 2025 strategy.[18]

Table 6. **Estimation of Small Hydropower Development Costs in Angola**

Name	*Cost (million USD/MW)*
Andulo	6.20
Kuito 2	6.17
Kuando	6.20
Liapeca	6.20
M'Bridge	6.17
Cuemba	6.20

Source: MINEA[18]

FINANCIAL MECHANISMS FOR SMALL HYROPOWER PROJECTS

The Angola action plan for the energy sector 2018–2022 mentions that the main sources of financing of energy sector projects are: the Public Investment Programme (ordinary revenue of the treasury or the external and internal funding); revenues and financing of companies in the sector; or private investment with contingency guarantees.[11] Some policies are planned to be defined in Angola, including financial incentives, such as:

- Agreement for power purchase (PPAs) with feed-in tariffs over a reasonable period of time;
- Setting rates of return-on-investment for capital;
- Tax reductions (e.g., on income tax and imports).

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The climate projections predict a continuous temperature increase of approximately 2 °C from 2040 to 2059. This increase will lead to a rise of evaporation and evapotranspiration. The loss of water by evaporation in a reservoir can reduce the attractiveness of storage SHP plants. Besides, climate change will globally decrease mean annual precipitation by approximately 13 mm in the same timeframe. The impact that increased temperature and evapotranspiration may have on runoff is yet uncertain and must be closely monitored since it may reduce the availability of water for SHP operation.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are still several barriers to SHP dissemination in Angola, including:

- Limited experience of developing energy projects with private investors, as IPPs under Build–Operate–Transfer (BOT) or similar arrangements, as well as in the form of public-private partnerships;
- Lack of stability in the rule of law and governance, for asset ownership, concession award and return, land acquisition, claim management, power purchase/selling and unpaid bills retrieval;
- Deficient long-term financial models for providing affordable renewable energy to customers;
- Limited availability of technologies for mini, micro- and pico-hydropower;
- Fragile operation and management framework, regarding norms and standards and human resources capacity;
- Power purchase agreements priced in the local currency.[4,29]

Nonetheless, there are also several enablers to SHP development in the country:

- Political will to facilitate investment in the energy sector;
- Favourable topography and water availability for SHP development;
- Increased presence of international financial institutions following the peaceful transition in presidential power in 2017.
-

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Cameroon

Joseph Kenfack, National Advanced School of Engineering

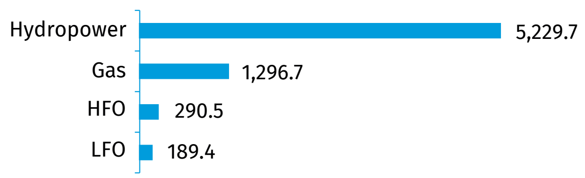
KEY FACTS

Population	27,224,262 (2021)[1]
Area	475,440 km^2
Topography	Four geographical regions can be distinguished in Cameroon. The northern region is occupied by a savannah plain sloping down towards the Chad Basin. The central region is a transitional area between the western and northern regions and is dominated by the Adamawa Plateau at 900–1,500 metres above sea level. The north-western region consists of volcanic mountains reaching over 2,400 metres, with Mount Cameroon (4,095 metres) being the highest point in the country. Finally, the west is occupied by lowlands reaching up to 600 metres above sea level.[2]
Climate	The climate differs between the north and the south of the country. In the south there are two dry seasons, in November–March and in June–August, with mean temperatures ranging between 22 °C and 29 °C along the coast. In the north, the dry season lasts from October to March and temperatures range from 23 °C to 26 °C.[3]
Climate Change	Climate change has significantly affected Cameroon and disrupted weather and precipitation patterns, making trend predicting more complex. The observed effects include more frequent extreme weather conditions, false starts to seasons, heavier rainfall and as a result floods as well as recurrent droughts, which, in turn, have resulted in the advancement of the desert. These impacts are expected to become more severe as global warming continues. By 2100, the average annual temperature is predicted to see a 1.5–4.5 °C increase depending on the region.[4]
Rain Pattern	The average precipitation varies from 500 mm to approximately 3,000 mm, peaking at 10,000 mm at Mount Cameroon.[5]
Hydrology	In the south of Cameroon, water flows towards the Atlantic Ocean or the Congo River catchment via the Sangha River and in the north, towards the Benoue River or Lake Chad. Thus, the river system can be broken down into four subsystems of different sizes. The Atlantic catchment is the largest of the four subsystems, with the Sanaga River alone draining a catchment area of 135,000 km^2 and having a plurennial flow reaching 2,000 m^3/s at Edea. The Sangha catchment includes three tributaries of the Sangha River, i.e., the Dja, Boumba and Kadei. The Sangha in its turn is a tributary of the Congo River. The Benoue River, forming the Benoue catchment area, is the largest of the Niger River's tributaries with a plurennial flow of 250 m^3/s. The tributaries of Lake Chad include the Vina and Mbere. Both rivers form the western branch of the Logone, which runs into the Chari that feeds Lake Chad.[6]

ELECTRICITY SECTOR OVERVIEW

Total electricity generation in Cameroon in 2019 was approximately 7,006 GWh, of which hydropower accounted for almost 75 per cent, gas for almost 19 per cent, heavy fuel oil (HFO) for 4 per cent and light fuel oil (LFO) for almost 3 per cent (Figure 1).[7]

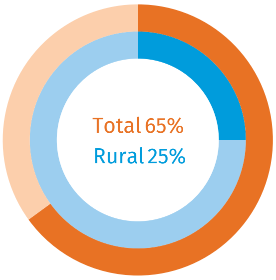
Figure 1. **Annual Electricity Generation by Source in Cameroon in 2019 (GWh)**



Source: Eneo[7]

The country's installed capacity is 1,547.3 MW, with hydropower accounting for 950 MW.[8] Hydropower is the main source of electricity generation. There are also several thermal power plants sustaining generation in grid-connected areas as well as operating off-grid. There are no electricity imports or exports, however, there are plans to connect Cameroon with Chad and Nigeria to mitigate the high cost of electricity generation in these countries. In 2020, the national electrification rate in Cameroon was nearly 65 per cent and the rural electricity access rate was 25 per cent (Figure 2).[9,10]

Figure 2. **Electrification Rate in Cameroon in 2020 (%)**



Source: World Bank[9,10]

The Ministry of Water and Energy (MINEE) and the Electricity Development Corporation (EDC) oversee the energy sector in Cameroon. The Rural Electrification Agency (AER) promotes rural electrification and the Electricity Sector Regulation Agency (ARSEL) approves electricity tariffs and determines electricity standards. The utility company Eneo is in charge of electricity generation and distribution, while the National Electricity Transport Company (SONATREL) manages the electricity transmission network. Cameroon has three main independent grids: the southern, eastern and northern grids. The electricity sector has been privatized since 1998. Kribi Development Corporation (KPDC), Dibanba Development Corporation (DPDC) and Memve'Ele are the most important generation companies outside Eneo. Nachtigal Hydro Company (NHPC) is constructing a 420 MW hydropower plant and will be the biggest generation company after Eneo.

After commissioning the first small hydropower (SHP) plants in the early 1930s, Cameroon switched to large-scale hydropower development, with a number of plants commissioned in the late 1980s. For several decades, no new hydropower plants were commissioned in Cameroon due to an unfavourable economic situation. Nonetheless, hydropower remains the main source of electricity generation in the country. However, there are also plans to develop large-scale solar power plants to reduce the currently high use or thermal power. The development of SHP can also have a high positive impact on the country, especially in rural and remote areas that experience such issues as high voltage drops due to the long distances of transmission and regular power shortages from selective power cuts or the aging medium-voltage network. Overall, in a developing country such as Cameroon, electricity demand is always on the rise (estimated to grow at an average annual rate of 4 per cent until 2040), to the point that the development of energy infrastructure does not manage to keep up, leading to selective power cuts even in large cities.[11]

The role of foreign investment is crucial for the development of the electricity sector in Cameroon. The ongoing generation projects are mainly funded through foreign funds as the national banking system provides very limited support to investment in the sector due to high interest rates.

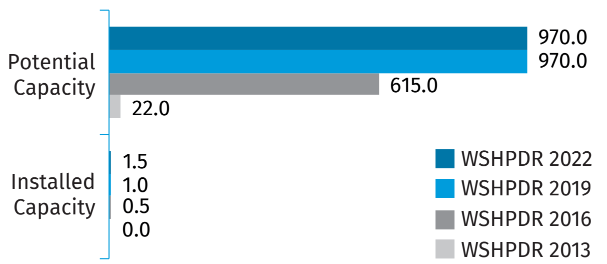
The electricity tariff system has remained unchanged since 2012. The rates are uniform all over the country and do not vary throughout the year but depend on the voltage level and the amount of energy consumed. Domestic consumers pay between 50 CFA/kWh and 99 CFA/kWh (0.077–0.150 USD/kWh).[12] Current tariffs do not represent the actual cost of electricity generation and are heavily subsidized by the Government.[13]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of SHP in Cameroon, however, there is a specific regulation for power plants of up to 5 MW for rural electrification. For the purposes of this chapter, the standard up to 10 MW definition will be followed.

In 2021, the 1.48 MW Mbakaou SHP plant was commissioned (Table 1), increasing the installed SHP capacity in the country compared to the *World Small Hydropower Development Report (WSHPDR) 2019*.[14] The Mbakaou plant became the first SHP plant to be developed in the country in decades and there are plans to further boost the SHP sector. The plants developed in the early 1930s were abandoned because of the grid extension from large-scale plants, but could be rehabilitated. There might also exist other smaller-scale plants developed by non-governmental organizations, such as the 20 kW plant in Tchouadeng, however, there is no accurate information on their installed capacity and operational status.[15] The total potential is estimated at 970 MW and remains unchanged compared to the previous edition (Figure 3).[16]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Cameroon (MW)**



Source: Afrik21,[14] *WSHPDR 2019*,[16] *WSHPDR 2013*,[17] *WSHPDR 2016*[18]

A detailed assessment of the SHP potential in the country is yet to be carried out, however, new SHP projects are most needed in the mountainous areas where the network experiences high voltage drops. One project under development is the 2.9 MW Ngassona plant (Table 2).

Table 1. **List of Existing Small Hydropower Plants in Cameroon**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Launch year*
Mbakaou Carriere	Mbakaou	1.5	15	2021

Source: Kenfack[8]

Table 2. **List of Planned Small Hydropower Projects in Cameroon**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Developer*	*Planned launch year*	*Development stage*
Ngassona (RUMPI)	Massaka	2.9	45	AER	N/A	Commissioning but stopped due to civil war

Source: Kenfack[8]

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

Table 3 shows a list of selected SHP sites available for development.

Table 3. **List of Selected Potential Small Hydropower Projects Available for Investment in Cameroon**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/refurbishment)*
Manjo	Manjo	4.6	24.3	New
Bafang	Bafang	2.9	100	New
Batie	Batie	1.6	115	New
Nchi	Maron	1.2	50	New

Source: Kenfack[8]

RENEWABLE ENERGY POLICY

The climate change policy is monitored by the Ministry of Environment in collaboration with other institutions. The Government's policies regarding renewable energy are being enhanced by new regulations under preparation, including plans and programmes relevant to SHP, especially the funds for feasibility studies.

According to the National Development Strategy 2020–2030, the country's total installed capacity is to reach 5,000 MW by 2030. The energy mix is to be based on hydropower, solar photovoltaics, gas-based thermal power and biomass. In the hydropower sector, the focus is on large-scale projects that are to be realized via public-private partnerships (PPP) or independent production. However, the Government will also encourage the construction of mini-scale hydropower to meet household demand for electricity. Legislation aimed at stimulating domestic private investment in such projects is to be developed.[19]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP is governed by the same regulations as the entire electricity sector. However, specific government plans and programmes targeting SHP are highlighted in the framework for rural electrification, especially for capacities below 5 MW. There are plans to review the legislation and regulations related to titles awarded to new plants, including SHP plants. The licensing process for SHP plants is the same as for other technologies and requires all documents from the feasibility studies, including the environmental impact assessment (EIA).

COST OF SMALL HYDROPOWER DEVELOPMENT

The total cost of the Mbakaou SHP project was approximately USD 6.9 million.[20]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

While subsidies and other incentives and forms of financial support can be obtained from the Government, SHP projects usually rely on foreign funds. Many international institutions are willing to fund the development of SHP in Africa, including Cameroon.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Despite the large potential and the strong will of the Government, the development of the SHP sector has been very limited so far. The key barriers to SHP development include:

- Lack of a detailed assessment of SHP potential;
- Lack of funds for SHP development;
- Need for capacity building;
- Lack of mature projects;
- Unreliable infrastructure;
- No local production of electromechanical equipment.

The key enablers for SHP development are:

- Great SHP potential,
- SHP can provide a solution to grid unreliability in rural areas;
- Liberalized sector;
- Available grid code;
- Strong policy focus on renewable energy development, including SHP.

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Central African Republic

Pedro Manso and Mathieu Barnoud, MHYD water & energy solutions sàrl

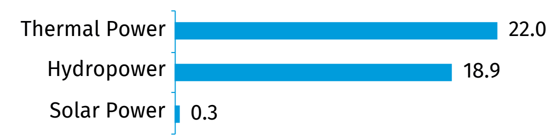
KEY FACTS

Population	4,745,185 (2019)[1]
Area	623,000 km^2 [2]
Topography	The Central African Republic is a landlocked country. The lowest point in the country is the Oubagui River at 335 metres above sea level, while the highest point is Mount Kayagangiri at 1,420 metres above sea level. Rolling hills cover the centre and the south of the country. The south-east is occupied by a dense tropical forest, while the northern part of the country is flat, similar to a savanna.[3]
Climate	The climate in the Central African Republic is warm, equatorial and humid, and has defined rainy and dry seasons. Temperatures vary between 19 °C and 30 °C during the wet season, from May to October, and range from 18 °C to 40 °C in the dry season, from November to April.[4]
Climate Change	Future climate scenarios indicate a temperature increase on the order of 1.4-2.2 °C, assuming low greenhouse gas emissions, and 1.8-2.7 °C, assuming high emissions. The probability of extreme climatic hazards occurring could increase with climate change, with the main hazards consisting of heavy rains followed by floods and droughts.[4]
Rain Pattern	Heavy rainstorms frequently occur during the rainy season (May–October). Maximum annual precipitation can reach up to 1,800 mm. In the Karre Mountains the average rainfall is estimated at 1,500 mm. The north of the country is drier than the south. The average annual precipitation across the country is 1,373 mm.[4,5]
Hydrology	There are important waterways harmoniously distributed across the territory of the Central African Republic. In the north of the country, the Chari River tributaries flow. The Ubangi River is one of the most iconic in the country, forming the southern border with the Democratic Republic of the Congo. The river has numerous tributaries, such as the Chinko, Kotto, Lobaye, Mbari and Ouaka. The Mbomou River (or Bomu) represents the Ubangi River’s headstream, flowing 725 km towards the west, and also contributes to forming the border with the Democratic Republic of the Congo.[4]

ELECTRICITY SECTOR OVERVIEW

The total installed capacity of the Central African Republic in 2019 was approximately 41.2 MW, including 22.0 MW of thermal power capacity, 18.9 MW of hydropower and 0.3 MW of solar power (Figure 1).[6]

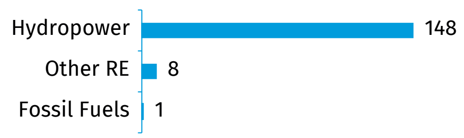
Figure 1. **Installed Electricity Capacity by Source in the Central African Republic in 2019 (MW)**



Source: African Energy Portal[6]

Gross electricity production was estimated at approximately 155 GWh at the end of 2018, and reached 157 GWh in 2019. Roughly 148 GWh were produced by hydropower in 2019, 8 GWh came from other renewable energy sources, and 1 GWh from thermal power plants (Figure 2).[7] Transmission losses are estimated at 7 per cent of the electricity produced in 2017, while distribution losses amounted to 33 per cent, which is higher than the average across Sub-Saharan Africa (between 18 and 20 per cent).[8]

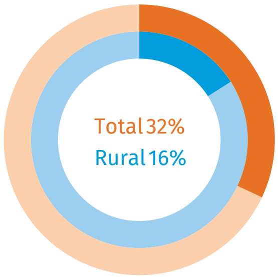
Figure 2. **Annual Electricity Generation by Source in the Central African Republic in 2019 (GWh)**



Source: AFREC[7]

Total access to electricity in the country reached 32 per cent at the end of 2019, indicating a three-fold increase since 2010.[9] However, access to electricity is unequally distributed between urban and rural areas. Thus, 55 per cent of the urban population had access to electricity in 2019 against 16 per cent of rural population.[9]

Figure 3. **Electrification Rates in the Central African Republic in 2019 (%)**



Source: World Bank[9]

Currently, the electricity supply in the Central African Republic remains lower than the demand. Furthermore, demand forecasts for the coming years predict a growth in peak demand from 80 MW in 2010 to 403 MW in 2030 in the low-growth scenario.[10]

The Ministry of Development for Energy and Water Resources (MDEWR) oversees the electricity sector in the country, with a Directorate General for Electricity established as part of the Ministry. The entity in charge of electricity production, transport and distribution is Energie Centrafricaine (ENERCA), which is a public organization founded in 1963 and owned by the Government. The two other main agencies in the Central African Republic are the Rural Electrification Agency (ACER) and the Autonomous Electricity Sector Regulatory Agency (ARSEC).[8]

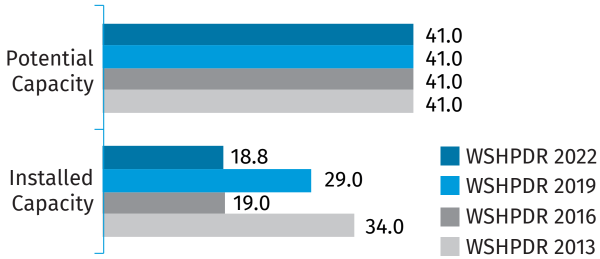
Hydropower in the country is delivered to the capital city of Bangui by two transmission lines with 17.5 MVA and 35 MVA of transit capacity. Losses in the electricity transmission and distribution system are high, due to the age of the facilities and difficulties to carry out adequate maintenance.[10]

Electricity tariffs are determined by cumulative hours of usage per month. The mixed tariffs for low-tension consumers in 2021 were 0.13 USD/kWh for usage of up to 65 hours, 0.14 USD/kWh for up to 130 hours and 0.15 USD for over 130 hours of usage. Mid-tension tariffs range from 0.044 to 0.070 USD/kWh.[11] Access to electricity in small cities and rural areas is very limited due to the price gap and the lack of infrastructure. To cover investment and operational expenses, the average electricity price should be approximately 0.2 USD/kWh.[12] This price difference induces a deficit of approximately USD 7 million per year (0.4 per cent of Gross Domestic Product).[12] The higher tariff needed is due mainly to losses in transportation and distribution as well as losses related to invoice collection and overstaffing, which are the highest in Africa, and represented 48 per cent of the budgetary deficit in the energy system in 2014.[12]

SMALL HYDROPOWER SECTOR OVERVIEW

The small hydropower (SHP) definition in the Central African Republic refers to plants of up to 10 MW. As of 2021, the total installed capacity of SHP in the country was 18.75 MW, made up of two plants: Boali I (8.75 MW) and Boali II (10.00 MW) (Table 1). It is estimated that Boali I could reach an additional capacity of up to 9.5 MW through rehabilitation works.[13] A further 10 MW was scheduled for the Boali III plant, which never was commissioned due to political instability in the country. At the current state, the Boali III plant is not complete and cannot produce electricity without a rehabilitation (dam monitoring and electro-mechanical devices). As a result of this, the total installed SHP capacity figure has decreased since the *World Small Hydropower Development Report (WSHPDR) 2019*, which counted the Boali III plant as operational. The potential estimate remains unchanged as no new data were made available (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in the Central African Republic (MW)**



Source: *WSHPDR 2013*,[14] *WSHPDR 2016*,[15] *WSHPDR 2019*,[16] Manso & Barnoud[17]

Table 1. **List of Operational Small Hydropower Plants in the Central African Republic**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Boali I	M'bali River	8.75	52	Run-of-river	ENERCA	1955–1969
Boali II	M'bali River	10.00	64	Run-of-river	ENERCA	1976

Source: International Journal on Hydropower & Dams[13]

Potential for SHP development in the country exists in the following locations: Baboua, Bambari, Bangassou, Berbérati, Bocaranga, Bossangoa, Bouar, Bria, Carnot, Kaga-Bandoro, Kembe, Mbaîki, Ndélé, Paoua and Sibut.[18] The SHP potential is estimated at 41 MW as was reported in the previous editions of the *WSHPDR*. Additionally, 30 sites suitable for development of hydropower plants of varying sizes were identified, with capacities between 0.5 MW and 180 MW.[19] However, the site names are not known.

The United Nations Development Programme (UNDP), in collaboration with the Global Environment Facility (GEF), attempted to develop electricity generation capacities and encourage investment in Western and Middle Africa, including the Central African Republic. The project aimed to develop 36 SHP plants in the region, alongside creating an SHP network. However, in 2011 the project was cancelled for the entire region due to regional political instability.[20]

Table 2. **List of Planned Small Hydropower Projects in the Central African Republic**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Developer*	*Planned launch year*	*Stage of development*
Boali III	M'bali River	10	~30	Reservoir	ENERCA	–	Feasibility study
Boali I bis	M'bali River	–	–	Run-of-river	–	–	Feasibility study
Boali II bis	M'bali River	10	64	Run-of-river	China Gezhouba Group Corporation (CGGC)	2022?	Under construction

Source: ENERCA[10]

The incomplete Boali III plant includes an embankment dam approximately 30 metres in height and 780 metres in length. The plant is located in the central concrete block of the dam between the overflow spillways, but has never been commissioned. The dam monitoring ceased in 2010. The dam is only used, at the current time, for water flow regulation for the hydropower cascade formed by the Boali I and Boali II plants downstream. Commissioning Boali III would allow adding up to 7.5–10.0 MW of capacity without an additional territorial footprint. A preliminary safety assessment was carried out in 2019 and revealed dam security and monitoring deficiencies. In the meantime, emergency measures have been recommended and further studies have started. It can already be stated that Boali III will need large civil and electro-mechanical works in order to put the 10 MW plant in operation and to secure water storage for the entire SHP cascade of Boali I, II and III.

A new power plant named Boali II bis is presently under construction next to the existing Boali II plant. Another new project called Boali I bis is planned downstream from the existing Boali I plant, but investment for it has not been yet secured.

In addition, ENERCA plans to develop small, mini- and micro-hydropower plants for a total of 40 MW before 2030. Additionally, also some larger hydropower plants (> 10 MW) are to be developed (Lobaye, Dimoli, Lancrenon, Kotto).[10] There are also plans to provide power supply to areas in the Central African Republic from the future Mobayi SHP plant in the neighbouring Democratic Republic of the Congo.[21]

RENEWABLE ENERGY POLICY

The Central African Republic aims to reduce its emissions by at least 5 per cent and 25 per cent by 2030 and 2050, respectively, compared to its baseline emissions in the business-as-usual scenario for both years.[22] The country also aims to reduce emissions of short-lived climate pollutants, which have a significant short-term global warming potential and harmful effects on health, agriculture and ecosystems. In addition, the entire national territory is exposed to extreme climatic hazards such as droughts and heavy rains followed by flooding. The Government aims to strengthen the country's resilience to climate change in key sectors.[22]

The Central African Republic envisages a holistic approach to climate change mitigation by integrating the adjustment of national policies and strategies, the improvement of legislative and regulatory frameworks, the development of capacities and technology transfers in certain priority areas. The following energy sources are being encouraged:

- Small and micro-hydropower plants;
- Solar thermal and photovoltaic energy;
- Processes for the methanization of organic matter;
- Improved carbonization.[22]

Apart from micro-hydropower plant development, the construction of a solar power plant at Bangui, a 72 MW hydropower plant at Lobaye, a 180 MW hydropower plant at Dimoli and the Mobayi hydropower plant is also planned in the next 15 years.

Micro-hydropower and solar power are the key targeted technologies, while most renewable energy sources, such as wind and geothermal power, are still widely unexplored in the country.[22] There is existent potential for the geothermal energy, however, no studies were conducted to determine it. Wind speed measurements show promising potential at above 5 m/s and, therefore, wind power could also be a viable alternative for electricity generation in the country. The high costs associated with the development of solar power might limit its use in the Central African Republic to certain applications or services.[23]

The economic reforms initiated by the Government to encourage private investment in the Central African Republic have led to the following framework document set:

- Law No. 01.10 of 16 July 2001, instituting a charter of investments in the Central African Republic;
- Ordinance No. 05.001 of 1 January 2005 on the Electricity Code of the Central African Republic;
- Decree No. 010.092 of 18 March 2010 defining the National Energy Policy.

These instruments provide a framework for investment in the energy sector but above all offer investors the means to implement their projects.[10]

There is no specific legislation or regulation for SHP.

COST OF SMALL HYDROPOWER DEVELOPMENT

No consolidated estimates of the average cost for the development of SHP in the Central African Republic are available. Of the three small Boali plants, only the cost of Boali III can be found in open sources.[24] However, the 10 MW capacity of this plant has never been fully installed and put into operation, therefore, the cost per MW may not be relevant. Cost estimates of the largest hydropower plant projects planned over the next 15 years were used to obtain an estimate of the cost per MW of installed capacity in the Central African Republic. The average cost of hydropower installed capacity appears to be approximately 3.7 USD/MW (Table 3). Average cost of SHP development is unavailable.

Table 3. **Cost Estimation for Hydropower Plants in the Central African Republic**

	Project cost (USD million)	*Cost per unit of installed capacity (USD million/MW)*
Dimoli (180 MW)	275	1.5
Lobaye (72 MW)	180	2.5
Kotto (60 MW)	500	8.3
Boali III (10 MW)	25	2.5
Average		**3.7**

Source: UNFCCC,[22] ADF[24]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Nowadays, the Central African Republic remains dependent on multilateral funding and donations (World Bank, African Development Bank and United Nations Industrial Development Organization) as well as bilateral financing (European Central Bank, French Development Agency and Export-Import Bank of China). This is not always a reliable way of funding projects, as they may be cancelled due to political instability in the region.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The evolution of rainfall due to climate change varies greatly according to the scenarios, with some projecting a slight increase in annual rainfall, while others project irregular variations in precipitation. Furthermore, there are no comprehensive studies for the Central African Republic showing the potential impact of future rainfall variation on available river runoff. Temperature increases may induce larger evaporation and therefore the water balance of existing reservoirs must be reassessed, in particular that of Boali III, where the reservoir surface is large (40 km^2). Besides, the probability of occurrence of extreme climatic hazards could increase with climate change. The main hazards are heavy rains followed by floods and droughts.[25] Existing SHP plants as well as new projects will need to be rehabilitated or designed to be resilient to such hazards (as recommended by the International Hydropower Association).

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are multiple barriers to SHP development in the country. Some of the most important ones are the following:

- The strong monopoly in the electricity sector disincentivizes investors, increases the project-related costs and limits potential profit;
- Lack of feed-in tariffs and other support schemes for SHP development;
- Lack of trained staff able to ensure efficient operation, maintenance and management of SHP plants;
- Limited financial resources and political unrest might deter future investment in SHP;
- No standards for SHP are developed in the region, which makes current access to electricity from SHP generators unreliable and affects the prospects for future projects.[13,20]

However, due to its known benefits and potential, also efforts are being made to implement future SHP policies in the Central African Republic. The main enablers for SHP development are:

- Existing contact with organizations in the field facilitates the development strategy (ENERCA, ACER);
- Climate and topography are suitable for hydropower development;
- The will to develop SHP and rural electrification projects;
- Local presence of International Financial Institutions;
- An investment programme through ENERCA, including SHP development scheduled between 2016 and 2030.

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Congo

Gilbert Nzobadila, African Energy Commission; Boniface Hervé Mabikana Voula, Ministry of Energy and Hydraulics1*

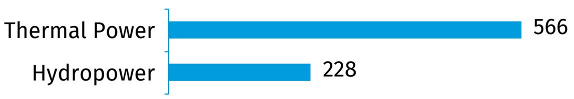
KEY FACTS

Population	5,518,000 (2020)[1]
Area	342,000 km[2]
Topography	The coastal area is a plain approximately 40 kilometres wide and 160 kilometres long between Gabon and Cabinda.[2] There are three dominant mountain ranges in Congo. The Mayombé Massif, or Mayumbe, is an old low-lying chain of mountains with deep river gorges that extends from the mouth of the Congo River in the south and to the Kouilou-Niari River in the north and parallels the coast.[2] The neighbouring Niari region hosts a valley and another mountain range, Chaillu Massif, reaching elevations of 400-700 metres above sea level before extending into south Gabon.[2] Beyond the Niari Valley lies a series of plateaus at approximately 490 metres. A vast plain occupies the north-eastern part of the country. The highest peak is Mont Nabemba (1,020 metres) located in the north-west.[2]
Climate	The climate in Congo is mostly hot and humid with heavy precipitation, due to the country's geographical location and the coastal plain. The north of the country has an equatorial climate, while the south has a tropical one. Average temperatures vary between 24 °C and 28 °C throughout the year.[3]
Climate Change	Congo is projected to see a 1 °C rise in mean annual temperatures by 2050 and to experience increased heat wave durations. The area will also see an increase in annual rainfall by 2046-2065 and an intensification of rainfall.[3]
Rain Pattern	Precipitation is abundant but varies throughout the year and across regions, with the equator crossing the country in the middle. The north of Congo experiences a dry season from November to April and a rainy season from April to November, whereas in the southern part the rainfall pattern is the exact opposite. Annual precipitation in the country averages 1,200 mm but often surpasses 2,000 mm. In the north, average annual precipitation ranges between 1,500 and 2,000 mm, while in the south precipitation can be lower than 1,500 mm and reach 1,200 mm near the coast.[2]
Hydrology	The major river is the Congo River. Its main northern tributary, the Ubangi River, flows southwards and forms the country's eastern border. The largest right-bank tributaries of the Congo River include the Sangha, the Likouala, the Alima, the Nkeni, the Lefini, the Djoue and the Foulakari.[2] The Kouilou-Niari is another major river that flows south-west from its source in the plateau region to Kayes and into the Atlantic. On the stretch from the Niari valley to Makabana it is known as the Niari River.[2]

ELECTRICITY SECTOR OVERVIEW

From 2018 to 2019, overall electricity generation in Congo increased by 5 per cent, however, most of this generation increase was made up by thermal power generation from the gas-fired Congo Power Plant (Centrale Electrique du Congo, CEC) Pointe-Noire (Figure 1).[4] In contrast, hydropower generation decreased by 22 per cent, from 1,120 GWh in 2018 to 872 GWh in 2019. This decrease mainly came from the Imboulou hydropower plant, whose generation in 2019 decreased by more than 30 per cent compared to 2018 (Table 1).[4]

Figure 1. **Annual Electricity Generation by Source in Congo in 2019 (GWh)**



Source: E2C (a.k.a E²C.SA)[4]

*Translated from French by Tamsyn Lonsdale-Smith, ICSHP

Table 1. **Annual Electricity Generation by Power Plant in Congo in 2015–2019 (GWh)**

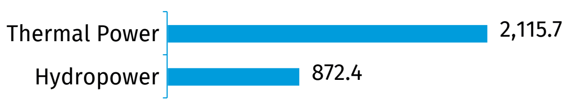
Power plant	*Installed capacity (MW)**	*Type*	*Annual generation (GWh)*				
			2015	*2016*	*2017*	*2018*	*2019*
Imboulou	120	Hydropower	703.5	684.4	702.8	645.3	433.1
Moukoukoulou	74	Hydropower	394.5	430.1	473.9	449.0	413.5
Liouesso	19	Hydropower	N/A	12.5	26.4	25.7	25.8
Djoué (non-operational since 2007)	15	Hydropower	-	-	-	-	-
CEC Pointe-Noir	484	Thermal power	1,434.5	1,643.5	1,646.7	1,719.2	2,115.3
Djeno (non-operational since 2018)	50	Thermal power	N/A	N/A	N/A	-	-
Brazzaville	32	Thermal power	4.8	2.2	2.0	3.0	0.4
Total	**794**		**2,537.3**	**2,772.7**	**2,851.8**	**2,842.2**	**2,988.1**

Source: E2C,[4] LCA,[5] ANDRITZ HYDRO,[6] E2C[7]

Note: *As of 2020.

As of February 2020, the installed capacity of Congo was at least 794 MW. Of this, thermal power accounted for approximately 71 per cent and hydropower for 28 per cent (Figure 2).[5,6,7] The renovation works of the gas-fired power plant CEC Pointe-Noire were completed in February 2020, increasing the plant's installed capacity to 484 MW and, therefore, the country's total installed thermal power capacity to 566 MW.[8] The total hydropower capacity is 228 MW, including the 15 MW of the non-operational Djoué plant. The largest hydropower plant in the country is the Imboulou plant of 120 MW, which came online in 2010 and supplies electricity to the city of Brazzaville. In addition to its domestic capacity, Congo imports 50 MW from the Inga hydropower plant in the Democratic Republic of the Congo (DRC).[5,6] The electricity grids of the DRC and the Republic of Congo are interconnected.

Figure 2. **Installed Electricity Capacity by Source in Congo in 2020 (MW)**

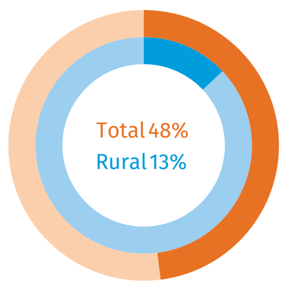


Source: LCA,[5] ANDRITZ HYDRO,[6] E2C[7]

More than half of the country's total installed capacity comes from the gas-fired power plant at Pointe-Noire (Table 1). The role of this plant is particularly important during the dry season when generation by hydropower plants decreases. The plant has three turbines, which have operated in parallel with the Inga hydropower plant in the DRC since 2015. The Government expanded the plant with the addition of a third 170 MW turbine. The two pre-existing turbines were at a capacity of 314 MW (each one was upgraded from 150 to 157 MW), bringing the total capacity of the plant up to 484 MW.[7] The work for this project commenced in 2019 and was completed on 18 February 2020.[8] The plant has the potential to reach up to 1 GW in the future with efficiency improvements and the addition of a proposed fourth turbine.[7] The Djeno thermal power plant has not been in operation since the transfer of its operating capacity to Kouilou Power SA in 2018.[9]

There are four hydropower plants in the country, however, only three of them are operational. In 2018, as part of the reforms undertaken in the sector, the Government launched the bidding for tenders for hydropower projects. The Djoué hydropower plant has not been functioning since 2007 due to flooding and subsequent rehabilitation work.[6] In 2018, Yunnan Linkun Investment Group agreed to rehabilitate the plant.[10] According to other sources, the task of completing a feasibility study and providing technical assistance for upgrading the power plant from 15 MW to 30 MW was awarded to Studio Pietrangeli Consulting Engineers.[11,14] It is unclear if any of this planned rehabilitation, extension and modernization work at the Djoué power plant is continuing as planned. The most recently constructed hydropower plant, the Liouesso plant, with a capacity of 19.2 MW, was commissioned in the northern Sangha Department on the Sangha River in 2017.[12] The installation of this plant aimed to foster economic activity in the region. Previously, users had access to electricity for only a couple of hours per day.[12]

Figure 3. **Electrification Rate in Congo in 2019 (%)**



Source: World Bank[13]

In 2019, 48 per cent of the country's population was connected to the electricity grid, and only 13 per cent in rural areas (Figure 3).[13] In comparison, 9 per cent of the rural population had electricity access in 2010, mostly due to access to mini-grids fuelled by diesel or gasoline.[14] The electricity demand of Congo has been growing and is expected to exceed 1 GW by 2027.[15] In particular, the demand of the Pointe-Noire special economic zone is expected to reach 700 MW, the demand of the city of Brazzaville 250 MW and the demand of the potash mines in Kouilou 150 MW.[15] With this in mind, the Government aims to increase the electricity generating capacity of the country.

The projects under development include the Chollet hydropower plant, with a capacity of 600 MW, which is to be jointly developed by Cameroon and Congo. The plant will be located in the Ngbala region of Congo on the Dja River and will make up part of the Central Africa Power Pool (CAPP). The project envisages the construction of electricity lines between the two countries and will interconnect their electricity networks. Congo will be the major beneficiary of the project, receiving 300 MW of the capacity, Cameroon will receive 60 MW and the remaining 240 MW will go to neighbouring countries. The contract on the construction of the plant was signed in 2010, however, little progress had been made until 2017 when the Intergovernmental Committee of the two countries met to confirm the intention to accelerate the development of the project.[16] Following another meeting in 2020, the technical and feasibility studies were scheduled to take place during the first quarter of 2021, after which the questions of financial mobilization and construction of the project are to be addressed.[17] Another project under consideration is the 80–100 MW hydropower plant of Mourala, on the Louessé River.[18] The feasibility study for the Mourala project has been completed and as of 2019 research for financing was underway.[19] A number of other potential hydropower projects are currently under consideration.[20]

On 9 April 2019, the Government of Congo and the Ministry of Energy and Hydraulics signed a memorandum of understanding with the China Railway 20th Bureau Group Co Ltd (CR 20GC) to develop the Gorges de Sounda hydropower project in the Kouiloi department.[21] The memorandum of understanding defined the manner in which the project will be implemented and that CR 20GC will lead the feasibility studies, including environmental and social impact reports, thereby completing preliminary studies undertaken by the International Finance Corporation (IFC). In November 2017, the IFC recommended a capacity between 486 MW and 616 MW and an optimal concept at a 70 metre full supply level, in consideration of the environmental and social impact of the project.[22,23] The studies performed by CR 20GC were expected to propose a higher capacity estimate than that proposed by the IFC study while minimizing the environmental and social impact. This new study is in response to the Government's aim to maximize the potential of the project and explore optimal options between 80 and 100 metres of full supply level.

The electricity sector of Congo is regulated by the Ministry of Energy and Hydraulics, and the National Agency for Rural Electrification (Agence Nationale d'Electrification Rurale, ANER) oversees the electrification of rural areas. In 2003 and after the creation of the Agency for the Regulation of the Electricity Sector (l'Agence de Régulation du Secteur de l'électricité, ARSEL), the sector was liberalized, legally ending the state-owned monopoly. However, a major role in the electricity market was still played by the state-owned company the National Electricity Company (Société Nationale d'Electricité, SNE), which was founded in 1967 through Law No. 67. SNE produced, transported, distributed and marketed electricity and maintained electrical infrastructure. After liberalization, it still held monopoly over electricity production until 2018.[24] The electricity sector opened up to private investors in 2018, and international financial institutions such as the International Monetary Fund and the World Bank have supported privatization, competition and economic reforms in the sector.[22]

In February 2018, the Government approved the plan to dissolve the SNE as well as the National Water Distribution Company (Societe Nationale de Distribution d'Eau, SNDE) since they proved to be inefficient and failed to reach sufficient profitability despite state investment. Following the sector reforms, the Heritage Company for the Electricity Sector (Société de Patrimoine pour le secteur de l'électricité, SPSE) was created. The creation of two other government agencies also ensued: the Society for Electricity Transportation (La Société de Transport de l'électricité, STE) and the Heritage Society for the Water Sector (La Société de Patrimoine pour le Secteur de l'Eau, SPSEA), which manage the sector based on public service concession contracts between the Government and public and private operators.[25] As of 2021, CEC S.A. is the main electricity producer, owned 20 per cent by ENI and 80 per cent by the state, and operates independently after attaining a licence from the Ministry of Energy and Hydraulics.[24] The reform of the electricity sector is expected to attract investment into the sector, and boost the struggling economy.[27]

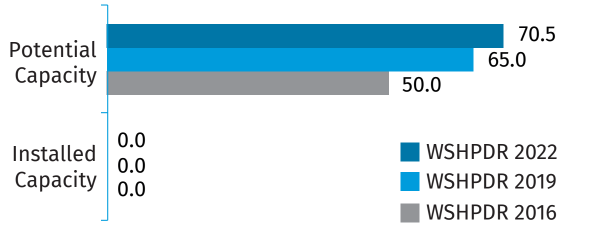
Electricity in Congo is transmitted via 110 kV and 220 kV lines and distributed via 30 kV, 20 kV, 6.6 kV, 380 V and 220 V lines. Following Decree No. 681 of 19 March 1994 by the Ministry of Commerce, Consumption and Small and Medium Enterprises, electricity tariffs in Congo have been unified across the country and divided into three categories: low voltage, public lighting and medium and high voltage. Electricity prices vary depending on these three categories and the level of consumption regardless of the type of consumer. Low voltage tariffs vary between 31.2 XAF/kWh (0.019 USD/kWh) and 49.08 XAF/kWh (0.030 USD/kWh).[28] Small producers outside of the national grid may negotiate prices with the consumers, according to Article 20 of the National Electricity Code.[14]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in Congo, therefore, this report uses the standard definition of SHP as hydropower plants with a capacity of up to 10 MW.

At present, Congo has four large hydropower plants. The smallest plant is at a capacity of 19.9 MW, the Liouesso plant, was commissioned in 2017 and constructed by the China Gezhouba Group.[29] The potential for hydropower development in the country has been estimated at approximately 14 GW, as defined by Government Decree No. 2010-822 of 31 December 2010.[29,30] The technical potential has been estimated at 3.9 GW, of which approximately 4 per cent has been developed.[25] The main potential for hydropower development is located in the Plateaux region, the Sangha region, Cuvette and Cuvette-Ouest. The potential for SHP development is assumed to be quite significant, but there are no publicly available feasibility studies and no ongoing SHP projects in Congo at this time. Compared to the results of the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed SHP capacity has not changed and stayed at zero, whereas the potential capacity increased by 9 per cent due to revised calculations (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2016/2019/2022 in Congo (MW)**



Source: *WSHPDR 2013*,[33] *WSHPDR 2016*,[34] *WSHPDR 2019*[35]

A Global Environment Fund–funded United Nations Development Programme (UNDP) project, Small Hydropower-based Mini-grids for Rural Electrification in Congo-Brazzaville, is planning 12 feasibility studies, but the project was still in its infancy as of 2019 and faced technical setbacks due to management and satellite data interruptions.[31]

The Hydropower Atlas developed by the UNDP in 2008 identified 17 potential SHP sites with capacities ranging between 6 kW and 6 MW and a combined capacity of almost 21 MW (Table 3).[18] Another study identified 10 potential sites with estimated capacities ranging between 5 MW and 10 MW with a combined capacity of at least 50 MW.[31] Based on these two estimates, the potential of SHP in Congo should be at least 70.5 MW. An additional feasibility study of seven potential mini-hydropower sites was proposed by the African Development Bank, and six feasibility studies are currently underway under the African Development Bank's Light up and Power Africa programme and expected to be approved for 2021.[32]

Although SHP could be used to meet the needs for electricity in rural areas as well as feed into the national grid, serving as an efficient and environmentally sustainable source, the sector has faced numerous barriers hindering its development. The gaps in the regulatory framework in relation to SHP projects, the lack of local skills to install, operate and maintain an SHP plant as well as of local technology make the sector less attractive than other power projects.[14] Another major barrier is low electricity tariffs.[34]

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

Table 2 offers details on SHP projects available for development in the country.

Table 2. **List of Selected Small Hydropower Sites Available for Development**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/refurbishment)*	*Type of project*
Mambouana	Lekoumou	0.43	424	New	Run-of-river
Assoumoundele	Sangha	6.18	202	New	Reservoir
Kimpanzou	Pool	5.51	380	New	Run-of-river
Kimbanda	Pool	4.02	250	New	Dam
Bela	Pool	3.18	260	New	Reservoir

Source: UNDP[14]

Note: Data from 2008.

RENEWABLE ENERGY POLICY

The Government envisages the development of renewable energy sources available in the country, including hydropower, biomass, solar power and wind power, in particular in remote areas. However, no policy or strategy promoting renewable energy has been developed to date. As a result, the available resources remain untapped.

The major laws and regulations of the electricity sector include:

- Law No. 14/2003 of 10 April 2003, defining the Electricity Code and liberalizing the market;
- Law No. 15/2003 of 10 April 2003, establishing the National Agency for Rural Electrification (ANER);
- Law No. 16/2003 of 10 April 2003, establishing the Agency for the Regulation of the Electricity Sector (ARSEL);
- Law No. 17/2003 of 10 April 2003, establishing the Development Fund of the Electricity Sector;
- Decree No. 2010-822 of 31 December 2010, approving the development strategy for the sectors of electricity, water and sanitation;
- Law No. 22-2018 of 13 June 2018 establishing the dissolution of the National Electricity Company (SNE);
- Decree No. 295-2018 creating the new Electrical Energy Society of Congo (Société Energie Electrique du Congo, E2C).

In accordance with the Electricity Act of 2013, independent power producers are required to obtain a licence. However, for small-scale projects of electricity generation, transmission, distribution and sales in rural areas, it suffices to obtain an authorization by the corresponding Ministry. Every project within the electricity sector is obliged to conduct an environmental impact study prior to the commencement of the project, according to Article 12 of the national Electricity Code. Financial incentives for the sector are non-existent.

COST OF SMALL HYDROPOWR DEVELOPMENT

The cost of transportation and distribution to remote villages can be quite high, especially in densely forested areas and when coupled with low demand, which lends the argument that in Congo hydropower investments should be made in close proximity to demand. In general, it costs 50,000 USD/km for 33 kV lines, and distribution costs can be as much as USD 2,000 per connection.[14] For this reason, the development of SHP is most economically feasible at the local village level and if connected to mini-grids.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The change in precipitation patterns and resulting hydrological shift in the country affect the potential of SHP development, mainly due to the risk of low water levels and unpredictability. There are frequent floods in the Congo Basin (Mossaka) and low-lying areas of the country.[32] Decreased rainfall leading to aquifer deficit has affected Point-Noire, putting pressure on the city's water supply and disrupting the operation of hydropower plants in the Niari Valley.[32]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Large hydropower is predominant in Congo, and the general trend in governance following the energy sector reforms in 2018 is to open up the sector to private competition. The Government is actively seeking maximum exploitation of power capacity and potential, despite preliminary environmental and social feasibility studies recommendations, as demonstrated by the rejected IFC study.

The SHP sector in Congo is currently non-existent, although several small-scale plants are in the planning phase due to international development programmes and investment. Meanwhile, the domestic hydropower sector has continued to invest in large-scale hydropower projects and thermal electricity generation. Due to the distribution and connection costs, SHP development is best suited to local, village-level projects.

The main obstacles to the development of SHP in Congo include:

- Low rainfall in dry season due to climate change that will decrease hydropower production, leading to decreased stability;[3]
- Gaps in the legal, regulatory and institutional framework;
- Lack of local skilled workforce to design, install, operate and maintain SHP plants;
- Lack of tax exemptions on SHP equipment;
- Low electricity prices;
- Low awareness of SHP among the population;
- Expensive transmission costs through densely forested areas;
- The country's current financial situation minimizes the potential for future financing programmes.[29]

Despite these barriers, Congo has significant water resources for the development of SHP. The national electrification policy is keen to develop this potential to serve rural areas remote from the national electricity grid.

The main enablers for the development of SHP in Congo include:

- Available SHP potential;
- Increased rainfall and intensity in wet seasons due to climate change could increase hydropower production;
- Existing interest from international development institutions in SHP development in the country;
- Liberalized energy market with a relatively restrained regulatory landscape.[3]
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Democratic Republic of the Congo

International Center on Small Hydro Power (ICSHP)

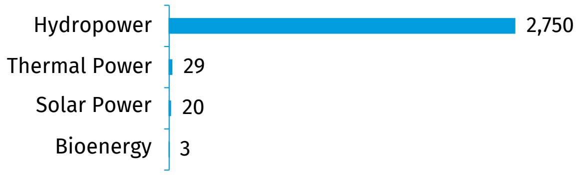
KEY FACTS

Population	89,561,404 (2020)[1]
Area	2,345,410 km^2 [2]
Topography	The Democratic Republic of the Congo (DRC) is a large and topographically diverse country with high plateaux, mountain ranges, a major valley, a large river basin and a low coastal plain. The Congo Basin, a large rolling plain at the centre of the country, has an average elevation of approximately 520 metres above sea level. The highest elevation in the country is at Margherita Peak, part of the Ruwenzori Mountain Range at the border with Uganda, with an estimated elevation of approximately 5,109 metres. This mountain range is part of the Western Rift Valley, which forms the country's eastern borders and includes the lakes Kivu, Edward, Albert, Mweru and Tanganyika. The active volcanic Virunga Mountains are also found in this area, at the border with Rwanda.[3]
Climate	The DRC has a largely equatorial climate with variations across the country's vast land area. The north and west of the country are hot and humid while the south, east and central areas are cooler and drier. The country's climate is driven by the seasonal migration of the Intertropical Convergence Zone across the equator. The mean annual temperature in the country is 24.4 °C. The northern and central to south-western areas average between 24 °C and 25 °C and the south and south-eastern savannah areas average between 22 °C and 23 °C. The tropical climate zones in the country experience a dry season (from April to October) and a rainy season (from November to March).[4,5]
Climate Change	Over the last 30 years, temperatures have been observed to increase by an average of 0.17 °C per decade. It is projected that the average temperature will increase by 1.7-4.5 °C and the average precipitation could increase by up to 8 per cent from the base period (1971–2000) by the end of the 21st century. Longer periods of dry seasons are also expected. However, no significant variations in rainfall patterns have been observed in the DRC.[5,6]
Rain Pattern	The DRC experiences a mean annual precipitation of 1,504 mm, with between 140 and 160 rainy days a year on average. In the central Congo Basin, precipitation averages between 1,800 mm and 2,200 mm a year. In the eastern regions, precipitation can reach 3,000 mm per year. In the coastal areas, the climate is drier and precipitation averages 810 mm a year.[6]
Hydrology	The DRC is home to over half of the African continent's surface water reserves and about one quarter of the continent's water resources, making it the most water-rich country in Africa. Approximately 30 per cent of the country's water resources originates from neighbouring countries. The Congo Basin covers approximately 98 per cent of the country, is the second largest in the world and hosts the world's deepest river, the Congo River. The other 2 per cent of the country is covered by the Nile Basin, which contributes approximately 20 per cent of the White Nile's flow. The DRC is also home to various rivers and lakes that it shares with its neighbouring countries, including the lakes Edward, Kivu, Albert and Tanganyika.[7]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in the Democratic Republic of the Congo (DRC) are hydropower and thermal power, accounting for 99 per cent and 1 per cent, respectively, of total production, which amounted to 9,990 GWh in 2019. A further 0.1 per cent was from solar power. Production from hydropower, non-renewable thermal power and solar power amounted to 9,855 GWh, 107 GWh and 28 GWh, respectively, in 2019 (Figure 1).[8]

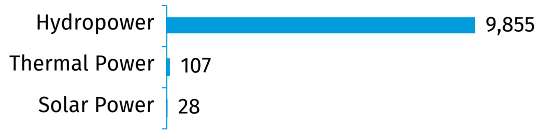
Figure 1. **Annual Electricity Generation by Source in the DRC in 2019 (GWh)**



Source: IRENA[8]

In 2020, the total installed capacity in the DRC was 2,802 MW with hydropower, non-renewable thermal power and solar power contributing 98 per cent, 1 per cent, 0.7 per cent and 0.3 per cent respectively. Installed hydropower capacity was approximately 2,750 MW, thermal power capacity was 29 MW, solar power capacity was 20 MW and bioenergy capacity was 3 MW in 2020 (Figure 2).[8]

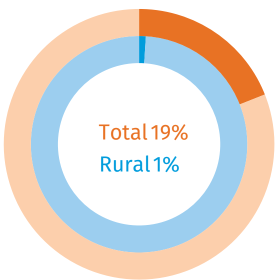
Figure 2. **Installed Electricity Capacity by Source in the DRC in 2020 (MW)**



Source: IRENA[8]

The electrification rate in the DRC was 19 per cent in 2020, with 49 per cent access in urban areas and 1 per cent in rural areas (Figure 3), making the DRC one of the countries with the lowest rates of electrification in the world.[9] There are significant issues of electricity shortage in the country, which make even customers connected to the national grid experience frequent blackouts. These issues are mainly caused by ageing and faulty equipment and lack of regular maintenance. Programmes for the rehabilitation of equipment were designed but have not succeeded in yielding considerable positive results yet mainly due to a gap in key skills and unrealistic objectives given the budgetary constraints.[10]

Figure 3. **Electrification Rate in the DRC in 2020 (%)**



Source: Energy Capital and Power[9]

The energy sector in the DRC is under the responsibility of the Ministry of Energy and Hydraulic Resources (MEHR), while the national utility responsible for the generation, transmission and distribution of electricity is the Société Nationale d'Électricité (SNEL). Due to the Government's promise to decentralize the electricity sector, private electricity operators have emerged, though remain regulated by SNEL. These include Virunga SARL, SOCODEE and BBOXX.[10]

Over the years, the electricity grid and transmission systems have been improved and enhanced. The high-voltage (HV) transmission system was 2,475.7 kilometres in 1970. This HV transmission system had extended to 5,260.7 kilometres by 1982, and by 2012 the distance serviced by the HV transmission network was 5,788 kilometres. In 2015, a second transmission system (400 kV) connecting Inga and Kinshasa and covering a distance of 277.3 kilometres was completed. This transmission network was financed by the European Investment Bank to reinforce and secure electricity generation for the city of Kinshasa. As of 2020, the total HV transmission system was 6,975.36 kilometres, including 1,774 kilometres of very HV direct current electric power transmission system extending from Inga in the west to Kolwezi in the south. There are several projects underway that aim to build transmission lines to neighbouring countries, including Uganda, Angola and Zambia. One of these projects is the proposed DRC–Angola Transmission Interconnector, which could link the two countries through a 250-kilometre 400 kV transmission line.[11,12,13,14]

There are several projects in various stages of completion to develop the energy sector in the DRC and increase access to electricity. These include the KivuWatt project, which has been partially completed and exploits the natural methane reserves of the Lake Kivu, shared with Rwanda, for electricity generation. There is also a concerted effort to accelerate the development of gas for domestic use, which could prove to be successful in providing value for the local community due to the country's vast resources in natural gas.[15,9]

The largest planned electricity project is the large-scale Grand Inga Dam Project, which, if completed, could single-handedly provide enough generation to meet 40 per cent of the continent's energy demand, making it the largest hydropower project in the world, with an estimated capacity of over 40,000 MW. One of the phases of the Grand Inga project, the Inga III dam, is currently underway and could provide 4.8 GW of capacity to the country. As the Inga III project advances, several other African countries have expressed interest in the project, with Eskom of South Africa and the Government of Angola signing agreements for the purchase of 2,500 MW and 5,000 MW of the project capacity, respectively.[9]

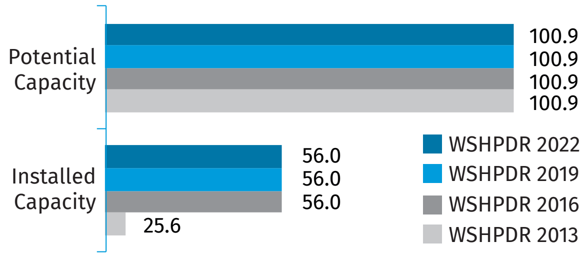
There are also projects that target other renewable energy sources such as the Kinshasa Solar City Project, which aims to build several solar power plants for a combined capacity of 1,000 MW. These energy projects contribute towards the country's goals of achieving universal electricity access by 2035 and reducing greenhouse gas emissions by 17 per cent by 2030.[9]

In the DRC, SNEL's tariffs are set by the Government and have not been revised since 2009 and are thus fixed at approximately 0.077 USD/KWh with variations based on inflation rather than changes in costs. Private operators fix their own tariffs in agreement with MEHR or relevant provincial authorities. Private operator Virunga SARL charges 0.21 USD/KWh (before taxes) in Goma and so does private operator SOCODEE for low-volume customers. For medium-volume customers, SOCODEE charges 0.16 USD/KWh. Private operator BBOXX charges between USD 17 and USD 100 per month for residential power service.[10]

SMALL HYDROPOWER SECTOR OVERVIEW

In the DRC, small hydropower (SHP) is defined as plants with an installed capacity of up to 10 MW. There was an estimated 56 MW of installed SHP capacity in 2017, which has not been updated as of the time of writing of this chapter. The total SHP potential identified has remained unchanged at approximately 101 MW since the previous edition of the *World Small Hydropower Development Report (WSHPDR 2019)* (Figure 4).[16]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in the DRC (MW)**



Source: *WSHPDR 2019*,[16] *WSHPDR 2016*,[17] *WSHPDR 2013*[18]

There are five planned SHP projects in the DRC in Butembo, Kakobola, Beni, Lungudi and Masisi (Table 1) out of approximately 780 sites that were found to be suitable for SHP development.[14,9,20,21,22,23]

Table 1. **List of Selected Planned Small Hydropower Projects in the DRC**

Location	*Potential capacity (MW)*
Butembo	9.50
Kakobola	9.30
Beni	2.40
Lungudi	1.50
Masisi	0.22

Source: UNDP[19], AfDB[20], IJHD[21], Energy Capitol and Power[22], Hydro Review[23]

RENEWABLE ENERGY POLICY

The DRC does not have a comprehensive renewable energy policy framework. There is, as part of the National Strategic Development Plan 2019–2023 (NSDP), a highlighted need for the development of renewable energy sources, particularly the tremendous hydropower potential. This, however, is accompanied by an emphasis on the development and exploitation of natural gas.[24]

There are no specific government policies that target SHP development and no direct incentives for the development of SHP by the Government of the DRC. There are, however, donors and funding institutions interested in investing in the development of RE since the Government authorized a liberalization of the electricity sector. These include the World Bank, the African Development Bank (AfDB), the European Union and the United Kingdom Department for International Development (DFIF).[25]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

In the DRC, SHP plants are regulated by the same legislation as larger hydropower projects. The main legislation and regulation documents in the DRC concerning hydropower are:

- The 2014 Electricity Liberalization Law ref. 14/011;
- The Decree No. 18/054 of 2018 on the reduction of production and import/export costs of electricity;
- The Decree No. 18/053 of 2018 on setting the conditions for the import and export of energy to/from the DRC.[26]

COST OF SMALL HYDROPOWER DEVELOPMENT

In the DRC, the construction costs of SHP are site-specific. The main cost indicators are waterfall height and strength, with the cost falling as the height rises (Table 2). These costs are estimated based on previously built plants.[26]

Table 2. **Mean Costs of Small Hydropower Construction in the DRC**

Waterfall height	*Construction costs (USD/kW)*
High (> 200 m)	1,500–2,000
Medium (30–200 m)	2,000–4,000
Low (≤ 20 m)	4,000–6,000

Source: ANAPI[27]

BARRIERS AND ENABLERS TO SMALL HYDROPOWER DEVELOPMENT

The development of SHP in the DRC is mainly hampered by:

- Weakened institutional and regulatory framework: the decentralization law, the 2014 liberalization, the state disengagement law and the law on public utilities' transformation have not been effectively enforced due to lack of institutional support. This constitutes a discouraging factor for private parties interested in SHP;
- The centralized grid expansion in the country favours large and centralized generation assets to the detriment of smaller and localized generators such as SHP;
- High cost of initial capital and lack of affordable financial mechanisms discourage potential investors in the energy sector;
- Lack of institutional support for small-scale electricity projects;
- Lack of clear renewable energy policy in the country.

Enablers for SHP development in the DRC include:

- The 2014 liberalization law promises the decentralization of the electricity sector, thus inviting private actors and international investors to get involved in the sector. This would, if enforced, provide an enabling environment for the development of SHP;
- The abundant water resources in the country and the multiple identified potential sites for SHP.

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Equatorial Guinea

Annabel Johnstone, Kaboni

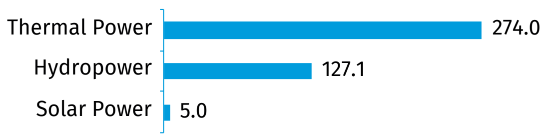
KEY FACTS

Population	1,432,744 (2021)[1]
Area	28,051 km^2[2]
Topography	Located in Middle Africa, Equatorial Guinea has a mainland region and an insular region. The latter comprises the islands of Bioko, which hosts the country's capital of Malabo, and Annobón in the Gulf of Guinea. The mainland of Equatorial Guinea begins on a narrow coastal plain, lined with mangrove swamps. From there, the land rises into an elevated plateau of thickly forested hills to the border with Gabon, reaching (in a few places) upwards of 1,219 metres above sea level. The highest point of Equatorial Guinea is Pico Basile at 3,008 metres and is located on the island of Bioko, which is dominated by three extinct volcanoes. The lowest point of the country is the costal border with the Atlantic Ocean (0 metres above sea level).[2]
Climate	The climate is tropical, hot and humid all year round with no specific rainy season, though rainfall is heaviest in October. The temperatures are higher from January to May (average of 27 °C in the city of Bata on the mainland and an average of 26 ° C in Malabo) and lower from July to September, when they drop to approximately 21 °C in the higher altitudes of the mainland, whereas Malabo experiences relatively constant temperatures all year round.[3]
Climate Change	Climate change projections for Equatorial Guinea encompass increased temperatures (average increase of 3-3.5 °C from a range of predictions under an average global temperature rise of 4.9 °C) and rainfall. Rainfall is projected to increase by a median of 40 mm in October-December, representing an increase of approximately 20 per cent.[4,5]
Rain Pattern	Mean annual precipitation is 2,205 mm, although rainfall patterns vary dramatically between the islands and mainland Equatorial Guinea. On the island of Bioko, precipitation is below 2,000 mm per year in Malabo, while it exceeds 3,000 mm per year in the rest of the island. The dry season on the island of Bioko runs from December to February, although it is more pronounced in the northern part, where Malabo is located; the rainiest period is from May to October. The slopes of Pico Basile experience high rainfall, with the location influenced by the prevailing wind. On the mainland, known as Rio Muni, there are two peak rainfall periods: from March to May and from September to November. The rains are also quite abundant from December to February, especially along the coast, and the only moderately dry period is from June to August.[3,4]
Hydrology	Aside from the sections of the Atlantic Ocean, the dominant water body is the Mbini River (known as the Woleu River in Gabon), which runs generally from east to west through central Rio Muni. To the north, the Campo River (called the Ntem in French-speaking Africa) marks part of the frontier with Cameroon. The Utamboni River flows through the south. To the south-west lies the Muni, which is an estuary of various rivers of Gabon and southern Equatorial Guinea. To the east, the de-facto border with Gabon follows the meandering course of the Kié (or Kyé) River, rather than the legal frontier.[6]

ELECTRICITY SECTOR OVERVIEW

Equatorial Guinea had an installed capacity of 406.1 MW in 2019, of which 127.1 MW came from hydropower, primarily from the Djibloho plant (120 MW) (Figure 1). This is set to more than double, once the 200 MW Sendje hydropower project is completed.[7,10] The completion date is unknown, but expected soon following a recent investment of EUR 122 million (USD 148 million) into the project. There is also a solar-powered micro-grid with a 5 MW plant installed in 2017 in Annobon.[8]

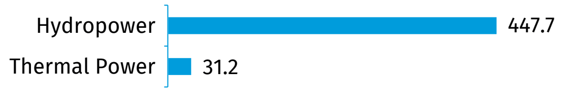
Figure 1. **Installed Electricity Capacity by Source in Equatorial Guinea in 2019 (MW)**



Source: Wise Power Systems,[8] African Energy Portal[9]

In 2019, the majority of the total electricity generation of 478.8 GWh was produced by hydropower (447.7 GWh), with the installed capacity of non-renewable sources (274 MW) only producing 31.2 GWh (Figure 2).[9] Final consumption was 598 GWh in 2019, excluding electricity imports, which are not documented. The amount of solar power generation from micro-grids is unknown.

Figure 2. **Annual Electricity Generation by Source in Equatorial Guinea in 2019 (GWh)**

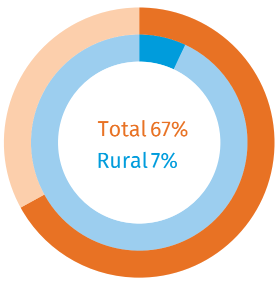


Source: African Energy Portal[9]

The state-owned electricity company Sociedad de Electricidad de Guinea Ecuatorial (SEGESA) under the Ministry of Mines and Hydrocarbons (MMIE) provides electricity under licensed monopoly and has several subsidiaries for generation, transmission and commercial operations. The SEGESA operates the country's two small electricity transmission networks, which comprise approximately 129 metres of high-voltage lines.[10] The network on the mainland serves the suburban area of Bata. The second distribution system, on Bioko, serves the capital Malabo and connects with the port of Luba. The electricity sector regulator is the Electricity Energy Regulatory Agency, while ownership of sectoral resources is left up to the national oil company GEPetrol. Equatorial Guinea is a member of the Central African Power Pool. Work on drilling three oil exploration wells in the Trident Energy-operated Block G oil production field commenced in 2021, and there are plans for the refurbishment and well intervention works across existing thermal plants.

In 2018, 67 per cent of the total population in the country had access to electricity: 90 per cent of urban residents and only 7 per cent of rural residents (Figure 3).[9]

Figure 3. **Electrification Rates in Equatorial Guinea in 2018 (%)**



Source: African Power Portal[9]

The Government of Equatorial Guinea is focusing on developing the fossil fuel industry within the country. In 2019, the Minister of Mines and Hydrocarbons (H.E Gabriel Mbaga Obiang Lima who is still in office at the time of writing) called for USD 1 billion of investment to develop 10 new fossil-based projects (of oil refineries and processing infrastructure). However, it is unclear whether suitable investment was raised for these projects.[12] The strategy to continue developing oil and gas resources in the country was repeated in discussions with the African Energy Chamber in 2020 as part of planning for recovery after the COVID-19 pandemic.[13]

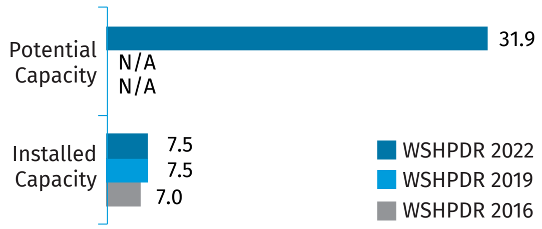
The Government of Equatorial Guinea has set electricity prices for enterprises and individuals in accordance with Law No. 3/2002. The electricity consumption price varies depending on the location and source of energy. Electricity consumers outside of Malabo and Bata are charged a fixed tariff per kWh. When the supplier is an independent producer, consumers are charged 0.099 USD/kWh. For independent diesel producers the price is 0.140 USD/kWh, while for independent hydropower producers the set price is 0.110 USD/kWh.[14]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in Equatorial Guinea. For this chapter, the definition of up to 10 MW will be used.

Although Equatorial Guinea is estimated to have 11–26 GW of hydropower potential, of which 50 per cent is deemed economically recoverable, SHP has received little attention in the country. Only three SHP plants were in use as of 2021.[11] In the south of Bioko, the old 3.8 MW hydropower plant in the town of Riaba has been operating at times at as low as 2 per cent of capacity due to lack of investment in maintenance and despite the increasing economic activity from the nearby freeport in Luba. The Riaba plant is to be refurbished and could see an increase in capacity to 6 MW, while the two micro-hydropower plants at Musola (0.4–0.5 MW) and Bikomo on the mainland (3.2 MW) are in need of upgrading.[11] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed SHP capacity remained unchanged (Figure 4). The reason for the change in potential capacity since *WSHPDR 2019* is due to access to a new geo-spatial study released in 2018.[18]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2016/2019/2022 in Equatorial Guinea (MW)**



Source: *WSHPDR 2013*,[15] *WSHPDR 2016*,[16] *WSHPDR 2019*,[17] Korkovelos et al.[18]

The Bikomo plant on the mainland (3.2 MW) was recently rehabilitated, as announced in a 2019 project review report.[19] Following the success of the Riaba and Musola plants, there were hopes for support for a 10 MW plant at Ilachi on Bioko island, as mentioned in a United Nations Development Programme (UNDP) project document.[19] Although details are not publicly available, a pre-feasibility study for the Ilachi location as well as water resource evaluations at sites in Belebu and Bococo Drumenwas were underway in 2019.[20]

Table 1. **List of Operational Small Hydropower Plants in Equatorial Guinea**

Name	*Location*	*Capacity (MW)*	*Launch year*
Musola I and II	Bioko	0.5	1942
Riaba	Bioko	3.8	1986
Bikomo	Rio Muni	3.2	–

Source: UNEP[11]

A geo-spatial analysis study conducted on GIS mapping software in 2018 identified 30 potential micro-hydropower sites (0.1–1.0 MW) totalling 10.9 MW and six SHP sites (1.01–10 MW) totalling 13.5 MW. The findings of the analysis suggest that there is at least 24.4 MW of undeveloped SHP potential in Equatorial Guinea. The exact locations, names and individual details of the sites are unknown, but the results from the geo-spatial mapping are visible in the study report.[18]

A separate study by Électricité du France (EDF) has identified 10 potential sites on Bioko Island at the six main rivers of the Cónsul, Balaopi/Tiburones, Musola, Tudela/Moaba, Ilachi, Ruma/Grande and Bao, though the individual capacities were not stated. The same study found that the most promising site for SHP development would be the Ilachi River with a height difference of 200 metres and a combined capacity of 12 MW in the dry season (and up to 18 MW in the rainy season).[11] The exact locations or names of these sites are not listed either and it is not known whether there is an overlap with the sites identified in the 2018 geo-spatial study. For this reason, the potential capacity estimate provided in this chapter is subject to error and potentially underestimated, due to possible overlap of data sources and lack of transparency.

Another project exploring SHP opportunities in Equatorial Guinea was conducted through the UNDP. The project aimed to complete a hydropower demonstration programme on the island of Bioko and to support the ongoing refurbishment of existing facilities at Riaba and Musola.[21] The project had a target of installing one SHP plant and as of 2019 this had not yet been achieved due to project delays.[19]

RENEWABLE ENERGY POLICY

Energy policy decision making in Equatorial Guinea primarily focuses on oil and gas developments, while in the power sector the focus is predominantly on larger-scale generation, grid extension and transmission concerns. Two main laws responsible for the energy sector are the Fundamental Law of 2012 and the Hydrocarbons Law No. 8/2006. As for the electricity sector, Decree 20/2005 allows for the transformation of the electricity sector.[14] Electricity tariffs were set by Decree No. 03/2002 of 21 May 2002.

Apart from the electrification plan, which was unveiled by the President in 2011, there is no longer-term renewable energy or off-grid electrification section or separate plan. There is a lack of procurement and licensing processes for independent power producers (IPPs), which creates only limited scope for renewable energy technology entrepreneurship and for IPPs in general.[14] There is no specific legislation relating to SHP and estimates of cost of SHP specific to the country are unavailable.

The European Union is a potential financing partner through the ACP-EU Energy Facility. The strong business relations between China and Equatorial Guinea may lead to additional development finance. Additionally, Spain and France continue to provide some project assistance.[21] The UNDP project on SHP mentioned above has been financed through the Global Environment Fund.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Equatorial Guinea is vulnerable to climate shocks and rainfall variability from climate change and measures are being taken within the country to address the risks, however, most are focused on forest conservation and weather analysis, rather than transitioning the energy system towards renewable electricity generation. These commitments are outlined in the country's National Adaptation Plan of Action (NAPA), which is overseen by the Ministry of Fisheries and Environment. However, within this plan, there is little mention of the energy system. There is also no large-scale international financial programme to specifically support these ambitions.[22]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Given the Government priority to develop oil and gas resources, it is not likely that Equatorial Guinea will become a priority location for SHP relative to other Middle-African countries, though there is a good availability of hydropower resources near large anchor loads (Bioko Island). Any SHP project in Equatorial Guinea will be entering an immature market and developers should expect the barriers that come with this, alongside a lack of institutional motivation for SHP.

Barriers to the development of the sector include:

- No consideration of innovative financing mechanisms for renewable energy developments (e.g., feed-in tariffs, carbon finance), nor regulation considering SHP development strategy;
- High upfront costs (augmented by custom duties) remain a factor further increasing the cost of introduction of renewable sources in a small market (no economy of scale);
- Policy objectives largely focus on expanding the oil and gas sector;
- Subsidized petrochemical products do not reflect the actual cost of fuel-generated electricity, distorting renewable generation as expensive;
- Data quality issues pertaining to the exact locations of the potential SHP sites identified.

Enabling factors include:

- Promising studies of viable sites for exploitation, particularly near the capital city on the island of Bioko;
- Interest in SHP from development institutions, such as the UNDP.

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Gabon

Annabel Johnstone, Kaboni

KEY FACTS

Population	2,172,579 (2019)[1]
Area	267,667 km^2 [2]
Topography	Gabon is divided into three distinct regions: a narrow coastal plain to the west, a hilly mountainous interior and a savanna in the far east and south. Rainforest covers nearly 85 per cent of the country's territory.[2] Significant mountains include the Cristal Mountains in the north-east and the central Chaillu Massif formed of granite, saddled by the Ogooué River, which carves through limestone. The highest peak in Gabon is Mount Bengoué, in the Crystal Mountains at an elevation of 1,070 metres. The highest peak in the Chaillu Mountains is Mount Milondo, at an elevation of 1,020 metres. The country also has hundreds of caves located in the dolomite and limestone rock formations in the central and eastern areas.[3]
Climate	Located on the Equator, Gabon has a hot and humid climate all year round in the north and in inland areas, with a short dry season from June to August. Average temperatures year-round range between 25 °C and 27 °C in coastal lowlands and between 22 °C and 25 °C inland. The country has experienced some of its highest temperatures along the coast and in the capital city of Libreville.[3]
Climate Change	Gabon has experienced a general warming trend with the mean annual temperature having increased by 0.6 °C since 1960. The number of hot days in the country is projected to increase by 25-75 per cent annually by 2060. Annual mean temperatures will increase by 1.8 °C by 2040-2059, according to the worst-case emissions scenario of up to 5.4 °C by 2100. Climate projections indicate that warming will occur across the country, with faster rates in the inland areas and slower rates in the coastal regions.[4,5]
Rain Pattern	Gabon receives an abundance of rainfall, typically ranging from 1,500 mm to 3,500 mm per year. The wet season lasts from October to May, with a mean monthly rainfall of 200–250 mm and peak average rainfall in October–November at 280 mm/month. However, mean annual rainfall in Gabon has dropped at an average rate of 3.8 mm monthly (approximately 2.6 per cent) per decade since 1960. The coastal areas of Gabon are expected to experience an increase in precipitation, while the inland areas may experience decreased precipitation. Country average precipitation is expected to experience a slight overall increase of 33.8 mm by 2040–2059, under a multi-model ensemble analysis of worst-case scenarios (RCP8). At the same time, rainfall variability is expected to increase with greater intensity and frequency of heavy rainfall.[4,5]
Hydrology	Gabon has substantial renewable water resources, with 166x10^9 m^3 per year, of which 98 per cent is produced internally and found as surface water (with a 36 per cent overlap with groundwater sources). The majority of the surface water is carried by the major river, the Ogooué (also spelt Ogowe), which is 1,200 km long and has several tributaries. Flowing through Gabon for almost its entire course, the river's drainage area extends for almost 222,700 km^2, within Gabon and also neighbouring Congo and Cameroon. The river originates in the north-east in Congo, and travels through the main watersheds of the Chaillu Massif and the Crystal Mountains, and empties into the Atlantic Ocean.[6,7]

ELECTRICITY SECTOR OVERVIEW

In 2019, Gabon had a total installed capacity of 632.3 MW, of which 334.3 MW came from renewable sources. The dominant renewable energy source in the mix is hydropower, accounting for 332.0 MW of installed capacity, with the remainder split between solar power (1.4 MW) and bioenergy (1.2 MW) (Figure 1).[8]

Net production plus imports of electricity in Gabon reached 2,331.5 GWh in 2018, compared to 2,327.1 GWh in 2017. In 2018, hydropower was the source of 980.9 GWh, a rise of over 7 per cent in just one year (913.6 GWh in 2017). Thermal generation stood at 839.8 GWh in 2018, down from 967.5 GWh in 2017.[10] Solar power and bioenergy generation were estimated at 2.1 GWh and 14.1 GWh, respectively, in 2018.[8] Thus, total electricity generation in the country in 2018 amounted to 1,836.9 GWh (Figure 2).[8,10] Gabon does not export electricity and is a net-importing country. Imports of electricity have been steadily increasing since 2013 and reached 445.6 GWh in 2019, demonstrating an increase of nearly 11 per cent compared to 2018.[8]

Figure 1. **Installed Electricity Capacity by Source in Gabon in 2019 (MW)**

Source: African Energy Portal,[8] Oxford Business Group[9]

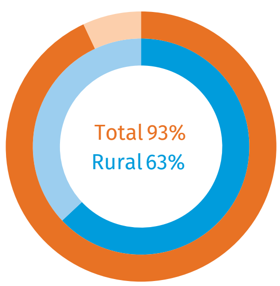
Note: This is an indicative estimate based on an average from several sources.

Figure 2. **Annual Electricity Generation by Source in Gabon in 2018 (GWh)**

Source: African Energy Portal,[8] SEEG[10]

Access to electricity across the population is at 93 per cent nationally, with 97 per cent in urban areas and 63 per cent in rural areas (Figure 3).[8] Increased household demand (15–20 per cent increase on a yearly basis in Libreville alone) is placing a strain on grid balancing. The Libreville grid — one of five isolated distribution areas in the country — is experiencing these pressures on the grid most strongly and load shedding still occurs in certain neighbourhoods. The lack of a national transmission grid has contributed to a tight supply-demand margin in a large number of the country's urban areas.[10]

Figure 3. **Electrification Rates in Gabon in 2018 (%)**



Source: Africa Energy Portal[8]

The Ministry of Mines, Petroleum and Hydrocarbons and the Ministry of Energy and Hydraulic Resources have joint responsibility for the energy sector. The Société d'Energie et d'Eau du Gabon (SEEG) is the sole generator, transmitter and distributor of electric energy in the country. SEEG is vertically integrated and holds a 20-year lease to the monopoly, which was renewed in 2017. Gabon is a member of the Central African Power Pool (CAPP).

The electricity sector is regulated by the Water and Energy Sector Regulatory Agency. The electricity tariff is capped at 0.23 USD/kWh for low-voltage single-phase power and declines to 0.09 USD/kWh based on usage (0.23 USD/kWh for 12 kW, 0.09 USD/kWh for 1 kW). For three-phase electricity, the tariff is calculated based on the time of use: for long use (over 2,880 hours), general use (1,441–2,880 hours) and short use (less than 1,441 hours) the tariffs are 0.13 USD/kWh, 0.15 USD/kWh and 0.16 USD/kWh, respectively.[11]

The electricity sector of Gabon and indeed its entire economy is currently heavily dependent on the large oil resources available within the country. Gabon is the fourth largest oil producer in Africa, and is considered to be in the top five richest African countries in terms of raw natural resources. The country has had plans to diversify the energy sector and remove oil dependence since 2010, as outlined in the Emerging Gabon Strategic Plan. The commitment to this objective was renewed in 2020 after the country was heavily affected by the oil price crash during the COVID-19 pandemic. With most of the population concentrated in the capital of Libreville and the rural population scattered in difficult to access areas, the current objectives are to enhance service to those connected, lower service prices and ensure access in rural communities.[12,13]

Since 2016 there have been four thermal plants in the country: two in Libreville, including a 128 MW plant in Owendo run by SEEG and a 70 MW plant in Alé nakiri run by the Social Democratic Party (SDP); and two in Port-Gentil, including a 48 MW plant operated by SEEG and a 52 MW plant run by the SDP, which is to be connected to the grid shortly. In addition to the SDP-owned 160 MW Grand Poubara hydropower plant that powers Franceville, Gabon has three major hydropower plants operated by SEEG. The Kinguélé plant has a capacity of 59 MW and is located roughly 200 km east of Libreville along the Mbei River, supplying Libreville via a 224 kV line. The second hydropower plant, Tchimbélé, is located along the same river and has a capacity of approximately 69 MW, while the third plant, Petit Poubara, near Franceville, has a capacity of 38 MW. The Grand Poubara and Alénakiri plants belonging to the SDP are operated under concession by China-based Sinohydro and Israel-based Telemenia.[14]

Several large hydropower projects are in development: the 85 MW Ngoulmendjim plant (550 GWh of annual generation) and the 15 MW Dibwangui plant (90 GWh) backed by the Gabonese Fund for Strategic Investments (FGIS) and Eranove; and the 35 MW Kinguélé-Aval plant (204 GWh) backed by FGIS and Meridiam. Furthermore, detailed preliminary studies of the Booué project on the Ogooué River (412 MW, 2,950 GWh) and the Tsengué-Lélédi project on the Ivindo River (300 MW, 1,286 GWh) have been initiated by the African Development Bank (AfDB) on behalf of the Economic Community of Central African States (EEECAS).[15] Gabon is examining financing options for two further hydropower projects: FE2 (36 MW, 240 GWh) and Empress Falls (88 MW, 500 GWh).[16]

In October 2019, French fund manager Meridiam signed a 33-year concession contract with the Government of Gabon to construct a 34 MW hydropower plant on the Mbei River, 100 km from Libreville. Construction was delayed due to the outbreak of COVID-19 and new projections state that the project will be completed in 2023.[17]

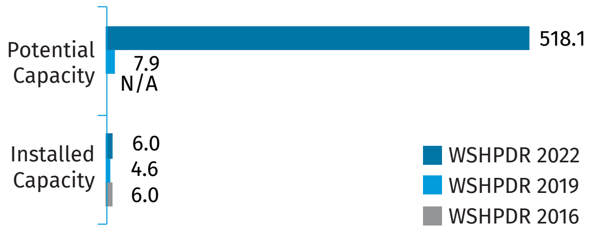
SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in Gabon. This chapter will use to the up to 10 MW definition of SHP. The hydropower sector in Gabon is heavily dominated by large-scale hydropower, and the country has significant hydropower potential of which an estimated 6,000 MW remains undeveloped.[18] Gabon has ambitions to become a net exporter of electricity in 2030, thus, the development of SHP to support internal electricity demand has viability.

There are three SHP plants in Gabon with a total installed capacity of 6 MW (Table 1).[19] There have not been any developments in the country's SHP sector since the publication of the *World Small Hydropower Development Report* (*WSHPDR) 2019*. However, SEEG launched a project worth USD 12.7 million for the rehabilitation of the Bongolo SHP plant, which operated at half (approximately 2.5 MW) of its installed capacity after 2010.[20] The change in installed SHP capacity since the *WSHPDR 2019* is a result of this rehabilitation work, and the change in potential capacity is due to access to new information from a geospatial feasibility study (Figure 4).

A geospatial assessment of SHP potential in Sub-Saharan Africa in 2018 found several opportunities to exploit mini- and small-scale hydropower in Gabon. The study found 105.9 MW of potential capacity at 343 sites with mini-hydropower potential (0.1–1 MW) and 412.1 MW of potential capacity available from 129 SHP sites (1–10 MW), resulting in a total of 518.1 MW of technical SHP potential. Though the locations and names of these sites are unknown, the mapped results from the geo-spatial analysis are visible in the study.[19]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2016/2019/2022 in Gabon (MW)**



Source: Korkovelos et al. 2018,[19] *WSHPDR 2016*,[21] *WSHPDR 2019*[22]

Table 1. **List of Operational Small Hydropower Plants in Gabon**

Name	*Capacity (MW)*	*Launch year*
Bongolo	5.46	1992
Mbigou	0.38	1996
Medounneu	0.20	1994

Source: Agence Cofin,[23] SEEG[24]

RENEWABLE ENERGY POLICY

In July 2020, Gabon laid out its ambitions to become an emerging economy in the region by financing a rapid and sustainable transition from a "brown" to a "green" economy. The Strategic Plan for Gabon's Emergence (PGSE) is supported by a number of international organizations and coordinated by the joint Sustainable Development Goals (SDG) fund (alongside a commitment of USD 1 million) to accelerate a transition away from an extractive and oil-based economy to a green and sustainable one. The PGSE was born out of the commitment of Gabon to lower its greenhouse gas (GHG) emissions in 2017 and bolstered by the large economic shock of the oil-price crash in 2020, incentivizing the country's transition away from unsustainable markets. The planned transition will open up the market for SHP in the coming years and place renewable energy developers as valuable partners to the Government of Gabon. The joint project's approach aims to:

- Build an Integrated National Financing Framework (INFF) for both the PGSE, the SDGs and the transition to a green economy;
- Prepare the ground, through study and market assessment, for expanded use of innovative green financing mechanisms to power the country's sustainable development;
- Rationalize the development financing ecosystem in Gabon;
- Develop national capacities in the mastery of SDG financing instruments to accelerate the achievement of SDGs related to climate change at the global level; and
- Establish an effective and inclusive system for monitoring public resources allocated to the transition to a green economy, aiming at creating a nation-wide SDG financing dialogue mechanism.[25]

Hydropower plays an important role in this transition through the creation of jobs, capacity building and enabling mitigation of the nation's dependency on oil and gas as the primary energy sources. Thus, promotion of hydropower is seen as one of the four pillars of green transformation acceleration alongside the creation of green jobs, promotion of green entrepreneurship for youth and women and sustainable cities.[26]

In light of the recent PGSE, it is highly likely that the regulations regarding renewable power generation will change imminently to the benefit of both utility scale and SHP developers through simplified and accelerated licence pathways and an increase in financial mechanisms to advance investment. This is especially the case as the PGSE represents the first targeted, holistic policy development for renewable sources in Gabon.[16] As reported by the Director General of the Ministry of Energy and Hydraulic Resources, a key change in the licensing process for hydropower will be a move from the outdated least-cost, project-by-project approach to a licensing procedure inviting multiple stakeholders to perform exploitation of all available sites in a river basin — a system-scale approach.[27] It is important to note also that due to the joint SDG approach, environmental standards and ecosystem services are seen as highly valuable and so any prospective projects are likely to require a detailed Environmental and Social Impact Assessment (ESIA) and environmental risk mitigation reports.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The above mentioned PGSE should inject much needed innovation into finance mechanisms for SHP and general private investments in the hydropower sector of Gabon. Planned or existing projects may also be financed through national or international institutions. The AfDB-financed Fund for Development and Expansion and the European Fund (FODEX) provide financing to small and medium-sized companies.

The Overseas Private Investment Corporation (OPIC), a United States Government agency, offers project financing in Gabon. There is also scope for finance from Gabon Special Economic Zone (GSEZ), which was started in 2010 as a joint venture between Olam International Ltd., the Government of Gabon and Africa Finance Corporation with a mandate to develop infrastructure, enhance industrial competitiveness and build a business-friendly ecosystem in Gabon.[28]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate predictions see an increase in rainfall in Gabon in all scenarios, so it is likely that the country will have increased total discharge.[4] This would require special consideration of construction materials and design, as landslides would be more likely.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Though attention will undoubtedly be focused on large hydropower projects due to the large natural resource base of Gabon, there is considerable scope for SHP development, especially in rural energy access schemes where export scale evacuation lines are less viable due to primary forest. More information is needed on the regulation changes coming through with respect to licensing procedures based on catchment basins rather than site-by-site licensing. For SHP, it would be beneficial to partner with large hydropower developers, to exploit this regulation change efficiently. Overall, Gabon looks promising for SHP development, keeping the below barriers and enablers in mind.

The key barriers to SHP development include:

- Legal framework and regulations are likely to change imminently due to the development of the PGSE;
- Lack of local expertise;
- Inadequate energy, water and transportation infrastructure;
- High levels of bureaucracy;
- Poor quality of state services;
- Relatively high labour costs.[20,25,26]

The key enablers include:

- The strategic plan of Gabon to transition from a "brown" to "green" economy opens huge potential for hydropower development;
- The Doing Business score of Gabon (45) has been steadily improving, with considerable improvement in ease of setting up a business.[29]

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Sao Tome and Principe

International Center on Small Hydropower (ICSHP)

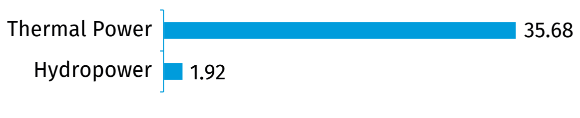
KEY FACTS

Population	219,161 (2020)[1]
Area	1,001 km^2[2]
Topography	Sao Tome and Principe is an archipelago consisting of two small islands and some islets located in the Gulf of Guinea, approximately 300 kilometres west of the African coast. The Islands are of volcanic origin and the terrains are predominately rugged with steep slopes, particularly in the western and southern regions on both islands. While volcanoes are present, neither island has experienced volcanic activity in recent centuries. The highest point is Pico de Sao Tome, at 2,024 metres, and is located in the western part of Sao Tome Island. The highest point on Pricipe Island is Pico de Principe at 948 metres, located in the southern region. Both islands have small coastal plain regions situated in the north-east.[2]
Climate	The islands have a tropical, maritime climate with little variation of temperature in a given region throughout the year. Temperatures in lower elevations and coastal regions are consistently in the upper 20s °C, while temperatures in higher elevations may drop to approximately 10 °C at night. Seasons are determined by rainfall with a dry season between June and August and a wet season between September and May.[2,3]
Climate Change	As islands, some of the most pressing concerns of climate change in Sao Tome and Principe are rising sea levels, coastal flooding and coastal erosion. These phenomena have been experienced already and are expected to intensify in the upcoming decades. Additionally, there have been noticeable elongated dry seasons, causing droughts, while prevalence of excessively heavy rainfalls and storms is increasing during the wet season, causing floods and landslides.[3]
Rain Pattern	Precipitation largely occurs during the wet season between September and May throughout the country, although average amounts vary by region, gradually decreasing from south-west to north-east. Average annual rainfall in the southern and western mountainous regions of both islands is above 5,000 mm and can exceed 7,000 mm in some areas. In the far north-eastern regions, annual rainfall is the lowest, approximately 760 mm.[2]
Hydrology	Within the mountainous terrain are many swift flowing rivers beginning in the country's interior highlands and flowing downwards to the coasts. The largest river is the Io Grande on Sao Tome draining in the south-east. Other important rivers on Sao Tome include the Abade, Manuel Jorge and Rio d'Ouro. The largest and most important river on Principe Island is Rio Papagaio. Many rivers have seasonal flows and weaken during the country's dry season.[4]

ELECTRICITY SECTOR OVERVIEW

In 2020, total installed capacity in Sao Tome and Principe was 38.6 MW, although total available capacity was considerably lower. On the country's grid, thermal power, largely diesel fuel, amounted to 35.68 MW (95 per cent) and hydropower to 1.92 MW (5 per cent) (Figure 1). Additionally, there were some other isolated systems in remote areas not connected to the grid amounting to approximately 1 MW. There are a total of 7 power plants in operation in the country, 6 of which are thermal power and 1 hydropower. None of the power plants operated with their full installed capacity in 2020, leaving a total available capacity of 22.15 MW (Table 1).[5]

Figure 1. **Installed Electricity Capacity by Source in Sao Tome and Principe in 2020 (MW)**



Source: EMAE[5]

Table 1. **Installed and Available Capacity in Sao Tome and Principe**

	Installed capacity (MW)	*Available capacity (MW)*
Sao Tome	34.80	20.31
Principe	2.80	1.24
Off-grid	1.04	0.60
Total	**38.64**	**22.15**

Source: EMAE[6]

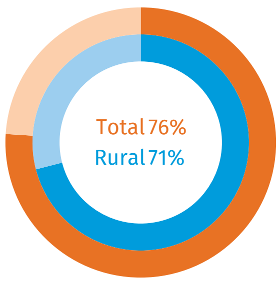
In 2020, total electricity generation was 109.6 GWh. Thermal power generated 104.7 GWh (95 per cent) and hydropower generated 4.9 GWh (5 per cent) (Figure 2). Net generation after energy used by power plants was 103 GWh. Due to significant inefficiencies, the electricity sector has experienced large annual losses in recent years and in 2020, losses represented 33.1 GWh, or over 32 per cent. After losses, the actual total electricity consumed in the country was 69.9 GWh for the year.[5]

Figure 2. **Annual Electricity Generation by Source in Sao Tome and Principe in 2020 (GWh)**

Source: EMAE[5]

The overall electrification rate in 2020 was 76 per cent, including over 78 per cent in urban areas and 71 per cent in rural areas.[6] Most of the electricity consumption in the country is concentrated in the capital city and surrounding areas. In 2020, there were 50,402 electricity customers that consumed a total of 69.9 GWh. The 42,489 residential customers represented 84 per cent of total customers and consumed 49 per cent of the electricity. Government and state institutions consumed 16 per cent of the total, commercial customers 13 per cent, industrial customers 8 per cent and the remaining 14 per cent was distributed amongst other types of customers.[5]

Figure 3. **Electrification rate in Sao Tome and Principe in 2020 (%)**



Source: World Bank[6]

In 2014 the electricity sector was restructured under Legal Framework of the Electricity Sector (RJSE) Decree-Law No. 26/2014. This decree essentially liberalized the market for private entities to invest in electricity production, however, there is a lack of clear regulation. As of 2020, the Government was working with external partners such as the United Nations Development Programme (UNDP) to create complimentary legislation that would further outline the standards for a liberalized market. Currently, the main electricity company is the Water and Electricity Company (EMAE), which is 51 per cent owned by the state and 49 per cent owned by private companies. EMAE is responsible for all the electricity production, distribution and transmission in the country. The distribution and transmission networks use a combination of underground and overhead medium- and low-voltage lines from 0.4 kV to 30 kV.[7]

With the support of international donors, the Government has made efforts to improve and extend the transmission and distribution network, construct new substations, transformation posts and a new national dispatch centre based on smart technologies and train technicians in order to adapt to the new quantitative and qualitative technological requirements of the public electricity service. In 2016 and 2017, transmission and distribution lines were rehabilitated and extended to the north and north-east to Santa Catarina Island and to the south of the island of Sao Tome as far as Sao Joao dos Angolares, as well as to Monta Alegre and Praia Burra in the island of Principe.[8]

Expansion of electricity access and reliability is incorporated into many of the recent national plans. The Sao Tome and Principe 2030 Transformation Agenda set out the Government's goals to pursue sustainable development, provide access to energy as an essential public good to the entire population, preserve the environment by designing projects that minimize negative environmental impacts and creating favourable conditions for the implementation of relevant environmentally friendly solutions and promote public-private partnerships with companies that have financial capital, technologies and human resources in the field of renewable energy.[7] The National Development Plan of 2017–2021 also highlighted the need to extend electricity access to the whole population as well as the need to rehabilitate the distribution and transmission infrastructure to avoid losses and increase energy efficiency, to increase electricity production through encouraging public-private partnerships and investments and to ensure a 50 per cent share of renewable energy sources on the grid by 2030. Additionally, the World Bank provided support to the Ministry of Infrastructure and Natural Resources with the preparation of a Least Cost Development Plan in 2018, which set out a roadmap to attain the necessary new generation capacities with the lowest cost investments.[7]

Electricity tariffs are set by EMAE and are approved by the General Regulatory Authority (AGER). Tariffs vary depending on the category and volume of consumption and are not differentiated by region due to the uneven distribution of the population across the country (Table 2).

Table 2. **Electricity Tariffs in Sao Tome and Principe**

Type of consumer	*Tariffs (STD/kWh (USD/kWh))*
Domestic:	
< 100 kWh	1.67 (0.07)
100–300 kWh	2.45 (0.11)
> 300 kWh	3.84 (0.17)
Commercial	3.84 (0.17)
Government, state institutions	6.03 (0.26)
Embassies, international institutions, other	7.03 (0.30)

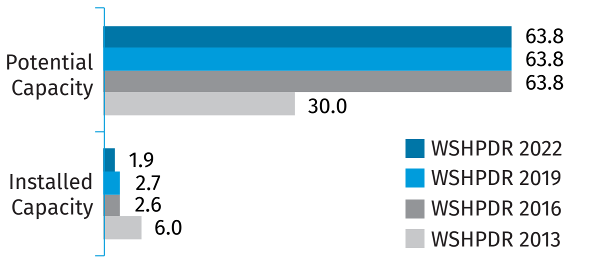
Source: EMAE[8]

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) is defined as power plants up to 10 MW, with a further breakdown into mini-hydropower (101 kW–1 MW) and micro-hydropower (1–100 kW). For the purposes of this chapter, all hydropower plants up to 10 MW will be considered SHP.

In 2020, the installed capacity of SHP in Sao Tome and Principe was 1.92 MW.[5] According to a study carried out in 2008 by CECI Engineering Consultants, Inc., there is a total potential capacity of 63.8 MW, indicating that just 3 per cent of the potential capacity is currently in operation.[7] Compared to the results of the *World Small Hydropower Development Report (WSHPDR) 2019*, potential capacity has remained the same and installed capacity has decreased due to removing plants not in operation for several years from the value of installed capacity (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Sao Tome and Principe (MW)**



Source: EMAE,[5] ALER,[7] *WSHPDR 2019*,[9] *WSHPDR 2016*,[10] *WSHPDR 2013*[11]

Historically, there have been four SHP plants in the country, although only one has been in operation in the past decade. The Contador plant, located in the north-western region on Sao Tome Island, has been in operation for over 50 years and is in need of refurbishment. The installed capacity is 1.92 MW but the current available capacity is approximately 1.8 MW. As of 2020, a rehabilitation project on the Contador plant has been approved with financial support of the World Bank with aims to increase the installed capacity to up to 4 MW. The budget for this project will be USD 39 million.[7]

The three old SHP plants that are now no longer in use are the Guégué, Agostinho Neto and Papagaio. The Guégué was constructed in 1941 with a capacity of 320 kW and closed in 2011. While some infrastructure is still at the site, the turbine and electrical system have been fully removed. In 2019, private company STP Urbano made an agreement to rebuild an SHP plant at that location. The company plans to demolish most of the remaining infrastructure and build a plant with a capacity of 1 MW. The commencement on construction of this project has not yet been announced.

The Agostinho Neto plant was constructed during colonial times and later modernized with a capacity of 344 kW. Due to electromechanical problems, the plant was dismantled in 2007 and has been inoperable since. STP Urbano has also shown interest in demolishing and rebuilding the plant, but no concrete purchase has been made. The Papagaio plant was the only hydropower plant to exist on Principe Island. It was constructed in 1993, first with an oversize 400 kW turbine but after two weeks changed for an 80 kW turbine that was in operation for just a few weeks before the transformer was brought to be installed at a nearby thermal power plant instead. In June 2020, a call for proposals to carry out a feasibility study on the project was launched, with no further updates since.[7]

The 2008 study of SHP potential in Sao Tome and Principe identified 34 sites with a combined potential capacity of 63 MW and estimated annual production of 244 GWh (Table 3).[7] The large majority of the sites are located on Sao Tome Island, while three of them are on Principe Island. Development of these sites would more than double total installed capacity and electricity generation for the country, as well as provide access to electricity in nearby remote communities.

Table 3. **List of Selected Potential Small Hydropower Projects in Sao Tome and Principe**

Name	*Location*	*Potential capacity (MW)*
Dona Eugénia	Io Grande River	9.6
Monte Rosa	Quija River	3.75
Bombaim	Abade River	3.5
Santa Irene	Lemba River	3.0
Claudino Faro	Abade River	2.0
Mato Cana	Abade River	2.0
Neves	Provoz River	2.0
Santa Luzia	Manuel Jorge River	1.15
S. João	Cantador River	0.9
Santa Clara	Manuel Jorge River	0.89
Cruz Grande	Do Ouro River	0.88
Monte Verde	Xufexufe River	0.80
Mateus Sampaio	Umbugu River	0.50
Almeirim	Agua Grande River	0.44

Source: ALER[7]

RENEWABLE ENERGY POLICY

Policy development, expansion and improvement of the energy sector, customer services and public services delivery all fall within the Government's priorities. The Government has mobilized resources to restructure the energy sector in order to create a more attractive investment environment, particularly for private investment in renewable energy infrastructure. Ongoing programmes, carried out with the support of development partners, are the main line of action. At present, no incentives or financial mechanisms exist to support the development of renewable energy sources, including SHP. However, regulations on renewable energy and SHP plants specifically are being drafted with the support of national and international consultancies.[9]

The National Development Plan 2017–2021 set targets for renewable energy including a 30 per cent share in electricity generation by 2021 and a 50 per cent share by 2030. In 2020, renewable energy share in electricity generation was 5 per cent, indicating that the 2021 target will most likely be missed. The renewable energy sources prioritized by the country are hydropower, solar power and biomass. There is not much potential for wind power on the islands due to the steep slopes of its terrain. There have been 34 potential sites identified for approximately 63 MW of hydropower, 25 sites for solar power for over 62 MW and one site for biomass identified for 12.5 MW.[7]

In 2019, the Global Environment Facility (GEF) and the United National Industrial Development Organization (UNIDO) approved a USD 24.93 million grant, of which USD 1.58 million would come directly from GEF and the rest would come from co-financing. This grant, named the Promotion of Investments in Renewable Energy and Energy Efficiency in the Electricity Sector, has multiple aims focusing on technical assistance and training. Activities in the scope of this grant include UNIDO working directly with the Government of Sao Tome and Principe to create clear renewable energy policies and create any legislation required to achieve them, as well as preparing a National Sustainable Energy Investment Plan to present to potential investors in at least two investment forums.[7]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

With the support of the UNDP, the Promotion of Sustainable Development and Hydroelectric Production Interconnected or in an Isolated Grid, more commonly known as The Energy Project, was created in 2017. It secured USD 20.7 million from multilateral and private sources to help establish the required institutional and legal framework for hydropower investment and development in the country.[12] A set of activities is underway with the objective of removing both technical and institutional barriers, including:

- Organizational restructuring of the Department of Natural Resources and Energy;
- Creation of support mechanisms and incentives for independent producers of electricity from renewable sources;
- Development and implementation of the Water Law;
- Development of the National Forest Development Plan;
- Update of the Forest Law.

Development of regulations for the electricity sector include:

- Regulation of energy generation from different sources of renewable energy (hydropower, solar photovoltaics, biomass and wind power);
- Sanctioning regime applied to electric power producers;
- Regulation of connection of new producers to the grid.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The Government of Sao Tome and Principe has worked with several international banks, donors and organizations to secure funding for SHP. In 2018, the African Development Bank through its Sustainable Energy Fund for Africa approved a USD 1 million grant for the development of mini-hydropower in Sao Tome and Principe. The grant is to provide the necessary funding for feasibility studies and environmental impact assessments at potential SHP sites. The aim is that the information gathered by these studies will attract investors in the sector. The initial locations that these studies will take place are at the Monte Rosa, Monte Verde and Santa Irene potential project sites.[7,13]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The country's hydropower sector has significant potential for development, as shown in the studies carried out. Therefore, boosting development will require raising private funds, taking into account the legal instruments that are being developed to increase the share of hydropower in the national energy mix and minimize the country's environmental impact.

The major barriers to SHP development in Sao Tome and Principe include:

- Institutional constraints due to the lack of a national strategy for hydropower and other renewable energy sources;
- Lack of an Electricity Master Plan;
- Lack of legislation and adequate implementation of the recommendations of the 2008 study by CECI Engineering Consultants, Inc.

The major enablers for SHP development in Sao Tome and Principe include:

- Most of the SHP potential is untapped and many sites have already been identified with their respective capacities;

- Access to electricity in the country is not universal, particularly in rural or remote areas. SHP development in remote areas can bring electricity to communities that have been without;
- Currently, fossil fuels account for 95 per cent of electricity generation. SHP could be vital to achieve the goal of 50 per cent renewable energy by 2030.

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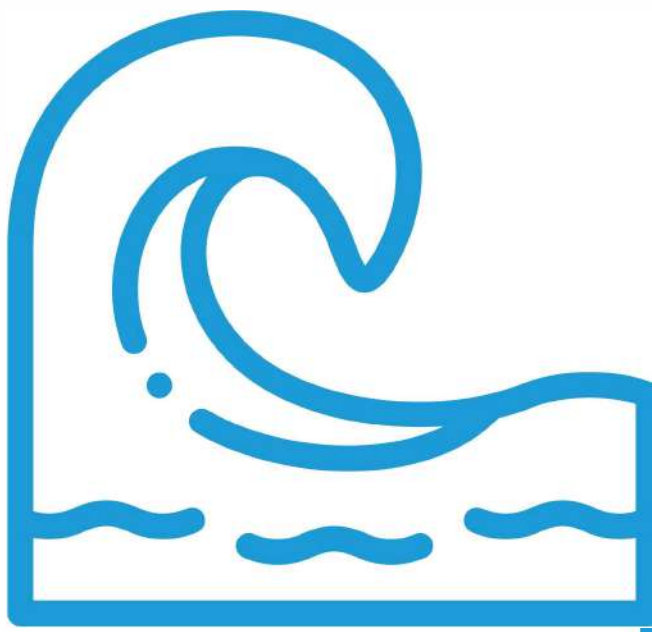


1.3. Northern Africa

Countries: Algeria, Egypt, Morocco, Sudan, Tunisia

INTRODUCTION TO THE REGION

The electricity sectors of countries in the Northern Africa region are characterized by the dominance of state-owned companies and, with the exception of Sudan, heavy reliance on fossil fuels. In Algeria, two public companies dominate the energy market, with one focusing on hydrocarbon production and trade and the other managing electricity production and distribution as well as gas distribution. Almost all of the country's electricity is generated from natural gas, combined cycle and steam power plants. The electricity sector of Egypt is divided between 16 state-owned companies operating under the umbrella of the Egyptian Electricity Holding Company. Thermal power plays the dominant role in electricity generation in the country, although a significant share of installed capacity and generation is accounted for by renewable energy sources. In Morocco, the electricity sector is dominated by the state-owned National Office of Electricity and Potable Water, which acts as the sole buyer of electricity and also operates some of the largest plants in the country. The primary sources for electricity generation in Morocco are coal and natural gas, while renewable energy sources serve in a supplementary role. In Sudan, the electricity sector is controlled by five companies under the Ministry of Energy and Petroleum. Hydropower and thermal power are both major sources of electricity generation in Sudan and are employed in a complementary capacity. Tunisia operates a partially liberalized electricity market. While the main actor in the country's electricity sector remains a state-owned company, smaller private companies also have a significant presence. Tunisia is heavily dependent on fossil fuels for electricity generation, with thermal power accounting for over 97 per cent of electricity generation in 2019.

The leading hydropower producer in the Northern Africa region is Sudan, where hydropower accounts for the largest share of generated electricity, although the installed capacity of thermal power slightly exceeds that of hydropower. In Egypt and Morocco, hydropower plays an important supplementary role in electricity generation. Egypt and Sudan share the Nile River as their primary source of both hydropower and irrigation, resulting in a complex but generally amicable shared water use relationship between the two countries. Tunisia and Algeria have some hydropower capacity, but its share of the electricity supply of both countries is relatively minor.

An overview of the electricity sectors of the countries in the Northern Africa region is provided in Table 1.

Table 1. **Overview of Northern Africa**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Algeria	43	100	100	21,999	87,034	228	152
Egypt	106	100	100	59,530	197,357	2,832	15,038
Morocco	36	100	100	10,677	40,348	1,770	1,654
Sudan	44	55	41	4,137	16,846	1,907	10,210
Tunisia	12	100	100	5,653	20,217	62	66
Total	**-**	**-**	**-**	**101,996**	**-**	**6,799**	**-**

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in Northern Africa varies by country. Algeria and Morocco adhere to the up to 10 MW definition of SHP, with additional subcategories for hydropower plants within the 0–10 MW range. By contrast, Sudan has adopted the up to 5 MW definition of SHP. There is no official definition of SHP in Egypt or Tunisia.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Northern Africa (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Algeria	Up to 10 MW	47.1	47.1*	47.1	47.1*
Egypt	N/A	N/A	N/A	0.0	120.0
Morocco	Up to 10 MW	30.5	300.0	30.5	300.0
Sudan	Up to 5 MW	N/A	N/A	7.2	2,228.6
Tunisia	N/A	N/A	N/A	17.0	56.0
Total	**-**	**-**	**-**	**101.8**	**2,751.7**

Source: *WSHPDR 2022*[1]

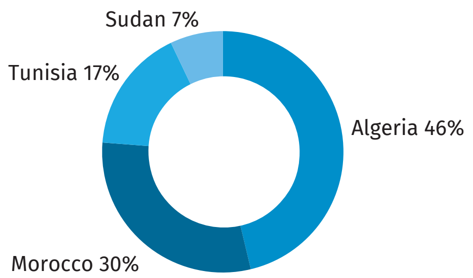
Note: *Based on installed capacity.

The installed capacity of SHP up to 10 MW in Northern Africa is 101.8 MW, while potential capacity is estimated at 2,751.7 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity decreased by approximately 9 per cent due to more accurate data on the operational status and installed capacities of existing SHP plants in Egypt and Morocco. The estimate of potential capacity for SHP up to 10 MW in the region increased five-fold due to a reassessment of the SHP potential of Sudan and Egypt.

While large hydropower plays an important role in electricity production in Northern Africa, the SHP sector in the region is very small by comparison, accounting for approximately 1 per cent of the total installed hydropower capacity. Little SHP development has taken place in the region over the last decade, with the installed SHP capacities of Egypt, Morocco, Sudan and Tunisia either remaining constant or declining due to the decommissioning of existing plants. The installed SHP capacity of Algeria has increased relative to the *WSHPDR 2019* as a consequence of the inclusion of a previously existing plant in the country's SHP total rather than any new developments in the last few years. SHP development in Northern Africa is hindered by a number of factors common to many countries in the region, including the availability of cheap fossil fuels, lower profitability of SHP relative to solar power and wind power plants and limited water resources in many parts of the region, as well as a lack of detailed data on potential SHP sites.

The national share of regional installed SHP capacity up to 10 MW by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

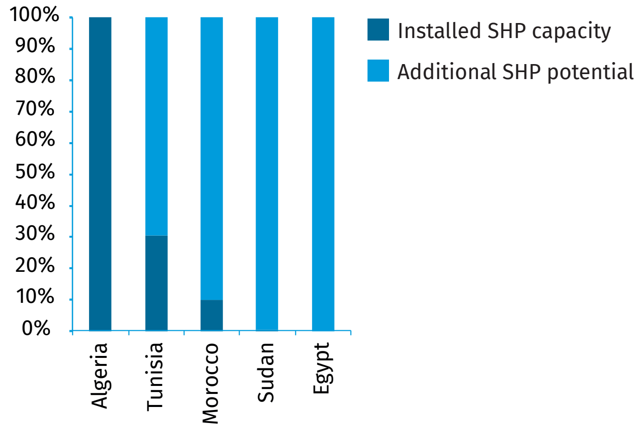
Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Northern Africa (%)**



Source: *WSHPDR 2022*[1]

Note: Egypt not included due to absence of SHP plants up to 10 MW.

Figure 2. **Utilized Small Hydropower Potential up to 10 MW by Country in Northern Africa (%)**



Source: *WSHPDR 2022*[1]

In **Algeria**, the total installed capacity for SHP up to 10 MW is 47.1 MW. As there are no reliable estimates of the country's potential capacity, it is currently assumed that all SHP potential in Algeria is fully utilized. The installed capacity of Algeria increased relative to that reported in the *WSHPDR 2019* due to the inclusion of the previously unreported Ighzerouftis SHP plant in the country's SHP total. However, no SHP development has taken place in the country in recent years. Furthermore, the Government of Algeria has indicated its intention to phase out hydropower in order to redirect available water for irrigation and drinking water supply, and hydropower development has been entirely excluded from the country's New National Programme for Renewable Energy Development 2015–2030.

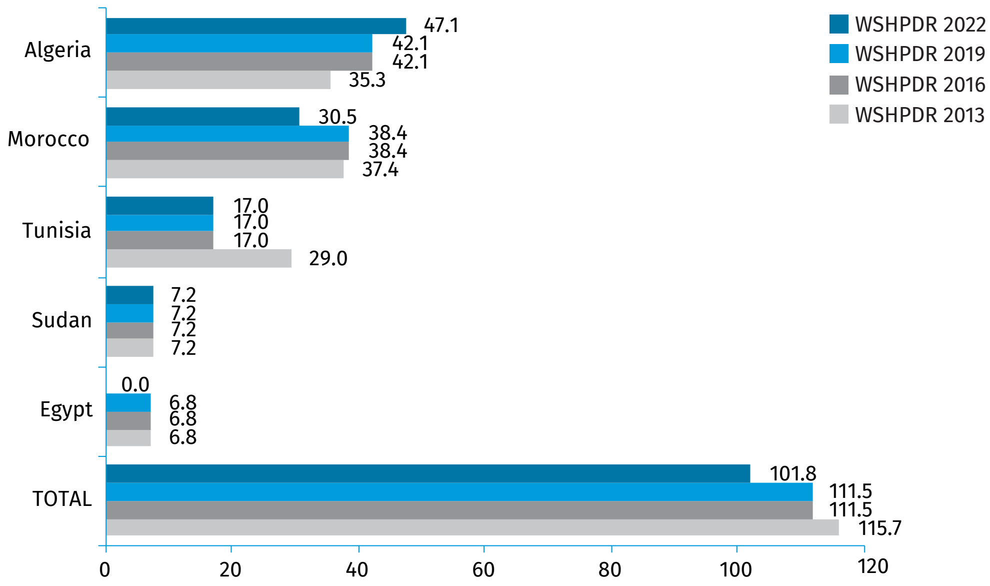
There were no operational SHP plants up to 10 MW in **Egypt** as of 2021, although several plants were in operation in the country in previous years. The potential capacity of SHP up to 10 MW has been recently revised from 51.7 MW to 120 MW. The country plans to develop several SHP sites with capacities ranging between 2 MW and 5 MW, although the project has not yet been confirmed due to concerns over its environmental and social impact.

Morocco has 30.5 MW of installed capacity for SHP up to 10 MW, while the potential capacity is estimated at approximately 300 MW, indicating that approximately 10 per cent of the SHP potential has been developed. As part of the Government's strategy to promote renewable energy sources by 2030, a number of hydropower projects have been approved for development by the private sector, of which 11 projects with a total capacity of 61.5 MW are under construction.

In **Sudan**, the installed capacity of SHP up to 10 MW is 7.2 MW, while the latest estimates put the country's SHP potential at 2,228.6 MW, indicating that less than 1 per cent has been developed. Although Sudan does not have an integrated renewable energy policy document, the country has been making efforts to develop its renewable energy potential and aims to reach at least a 50 per cent share of total electricity generation produced by renewable energy sources by 2031.

The total installed capacity for SHP up to 10 MW in **Tunisia** is 17 MW, while the estimated potential capacity stands at 56 MW, indicating that 30 per cent of the known potential has been developed. There has been no change in either installed SHP capacity or estimated potential capacity of the country since the *WSHPDR 2019*. The renewable energy strategy in Tunisia is focused primarily on solar and wind power. By contrast, the development of SHP has received relatively little interest in recent years, although in 2019 the National Company for the Exploitation and Distribution of Water of Tunisia invited bids for the construction of two micro-hydropower plants. The status of these two projects is currently unknown.

Figure 3. **Change in Installed Capacity of Small Hydropower up to 10 MW from *WSHPDR 2013* to *WSHPDR 2022* by Country in Northern Africa (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key barrier to SHP development in **Algeria** is weak support for renewable energy technologies and a trend away from hydropower development in particular. Additional barriers include limited financial resources and the low cost of generation from fossil fuels. In light of the Government's decision to not only halt the future development of hydropower but to additionally phase out existing hydropower capacities due to water scarcity, there is little prospect for SHP development in the country.

Barriers to SHP development in **Egypt** include competition from other renewable energy sources, lack of Government interest in SHP and inadequate data on available SHP potential. However, as the Government's policies on renewable energy sources have been formulated fairly recently, the possibility exists that the utility of SHP for diversifying the country's energy mix may be reconsidered in the future. In addition, the country's substantial undeveloped SHP potential, including the large number of irrigation canals and other hydraulic infrastructure, presents many opportunities for SHP development in certain parts of the country.

While **Morocco** has made considerable progress in diversifying its energy mix, SHP development in the country faces stiff competition from wind power and solar power, with returns on investment from SHP projects being less attractive than those from other renewable energy sources. Lack of public interest in SHP and of focused research in the field, as well as concerns over the country's limited freshwater resources, pose additional obstacles for SHP development. Nonetheless, the availability of data on potential SHP sites could serve as the basis for future interest in SHP development in the country.

The development of SHP projects in **Sudan** is hampered mainly by the lack of a comprehensive renewable energy policy, the Government's focus on large hydropower at the expense of SHP, irregular rainfall and low expected returns on investment. At the same time, Sudan possesses the greatest known undeveloped potential in the region for SHP up to 10 MW and emerging renewable energy policies may favour SHP development in light of the country's ambitious renewable energy targets to 2030.

Key barriers to SHP development in **Tunisia** include limited technical capacities and limited specialization to undertake feasibility studies, competition with conventional and renewable energy sources and a lack of stable funding for SHP. At the same time, Tunisia has experienced a marked increase in rainfall in recent years, leading to dramatic increases in annual hydropower generation from existing capacities. If this trend continues, it could make hydropower and SHP in particular a more promising source of renewable energy in the country.

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Algeria

Amine Boudghene Stambouli, University of Sciences and Technology of Oran; and International Center on Small Hydro Power (ICSHP)

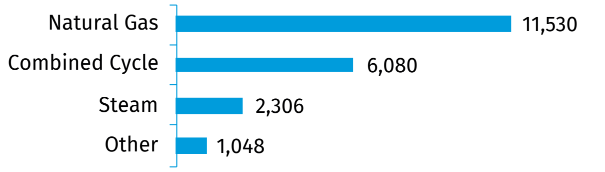
KEY FACTS

Population	43,424,000 (2019)[1]
Area	2,381,741 km² [2]
Topography	Algeria is made up of four main topographic zones. To the north, along the Mediterranean coast (1,200 km), stretches the narrow Tell plain, varying in width from 80 km to 190 km. The Tell Plain and the adjoining valleys are home to most of the country's agricultural land. On the borders of the Tell, two mountain ranges are oriented from east to west: the Tell Atlas to the north and the Saharan Atlas to the south, which merge towards the east of Algeria, forming the Aures massif. South of the Saharan Atlas stretches the Sahara Desert, representing 80 per cent of the surface area of Algeria. South of the Sahara stretches a succession of desert highlands, the Hoggar massif, where the highest peak in Algeria, Mount Tahat at 3,003 metres, is located. Approximately half of the territory of Algeria lies at 900 metres or more above sea level and approximately 70 per cent of the area is between 760 and 1,680 metres in elevation.[2,3]
Climate	The north of Algeria is in the temperate zone and its climate is like that of other Mediterranean countries, although the diversity of the relief creates strong temperature contrasts. The coastal region has average winter temperatures of 10-12 °C and average summer temperatures of 24-26 °C. Further inland, winter temperatures average 4-6 °C, with frost and occasional snow on the massifs; summer temperatures average 26-28 °C. In the Sahara Desert, temperatures range from 10 °C to 34 °C, with extreme peaks of 49 °C.[4]
Climate Change	Climate experts estimate that due to global warming, temperatures in Algeria will rise by 4-4.5 °C by 2050. As a result of the increased frequency of torrential rains, in 2009 the highlands of Ghardaïa and Bechar experienced flooding for the first time, and in the south of the country, in 2020 daily rainfall exceeded the normal annual average. Other observed consequences of climate change include high sea levels and destructive waves, causing erosion and even disappearance of beaches to the west of Algiers, demographic pressure, reduction in water run-offs, scarcity of water resources, degradation of hydraulic infrastructure and threat to wetlands.[5]
Rain Pattern	Precipitation patterns in the country can be separated into four key regions. The first region is located to the east in the high plains, and includes the Sersou plateau (Ain-Oussera region, Ksar el Boughari), while to the west it includes the region of Ras el Ma. These territories lie in relatively high altitudes (580–1,194 metres), are sheltered and characterized by low and irregular rainfall with averages of less than 400 mm per year. The second region, located in the west and the centre of the country, is characterized by a position of relative shelter from the rain flows from the west and north-west and low relief. The annual precipitation averages are below 500 mm and are slightly less irregular than in the first region. The third region, encompassing mountainous areas as well as the high interior plains, receives irregular rainfall, with the annual average ranging from 500 mm to just over 800 mm. The fourth region is located in the east of the Tell Atlas and experiences irregular precipitation with maximum rainfall in the cold autumn and winter and minimum in summer, with annual averages ranging from 488 mm to 854 mm.[6,7]
Hydrology	The estimated amount of renewable water resources in Algeria is approximately 19 billion cubic metres per year and approximately 450 cubic metres (m³) per capita per year. This is below the recommended 500 m³ per capita per year scarcity threshold, indicating a water crisis in the country. Furthermore, water resources are characterized by high variability. The rivers in Algeria are numerous, but the majority of them have short courses. They mostly rise in the mountains near the coast and flow with great force through deep and rocky channels, presenting the characteristic mountain torrents. The Chelif River, the longest and most important river of Algeria, runs between the Atlas Mountains and Mediterranean Sea, is 725 km long and has an irregular flow, with the longest continuous flow being from November to March. The Djedi River is 479.6 km in length, making it the second longest river in Algeria. Similar to the Chelif, it begins in the Saharan Atlas Mountains at an elevation of 1,402 metres. The Djedi empties into Lake Chott Melrhir, which is located at 3.6 metres below sea level, the lowest point in Algeria.[6,7,8,9]

ELECTRICITY SECTOR OVERVIEW

Total electricity generation in Algeria was 87,034 GWh in 2019 (Figure 1).[10] Of this, 81,526 GWh came from state-owned power plants and independent power producers, while 5,508 GWh came from autonomous production.[10] More than 99 per cent of energy production and consumption, including in the electricity sector, is derived from natural gas and produced from 33 stations located in the southern region of the country.[11] Electricity production growth has been two times slower since 2015 and is almost entirely from gas.

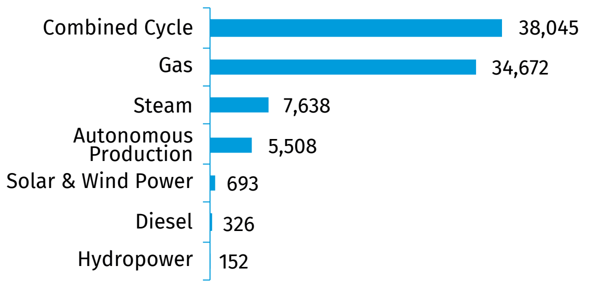
Figure 1. **Annual Electricity Generation by Source in Algeria in 2019 (GWh)**



Source: Ministry of Energy[10]

Algeria had an installed electricity capacity of 21,999 MW as of 2020.[12] This included an installed hydropower capacity of 276 MW and 400 MW of solar photovoltaics (PV), mainly off-grid.[13] According to the International Renewable Energy Agency (IRENA) statistics, in 2019, Algeria had a total renewable energy installed capacity of 686 MW (433 MW of which being off-grid). Of this, 228 MW was from hydropower, 10 MW from wind power and 448 MW from solar power (of which an estimated 25 MW was from concentrated solar power).[14] The most recent data that compare installed capacity from all energy sources are from 2018 (Figure 2).

Figure 2**. Installed Electricity Capacity by Source in Algeria in 2018 (MW)**



Source: Ministry of Energy[15]

Note: The values by source were calculated based on percentage values of the total. The Category "Other" includes installed capacity from diesel, solar power, wind power and hydropower plants.

A further 150 MW of solar PV projects, including seven sites and 15 projects of 10 MW each were released as tenders in 2019.[16] Furthermore, the state oil company Sonatrach has launched a solar expansion programme of 1,300 MW, which is to cover 80 per cent of the electricity needs for its oil facilities, of which 344 MW are already in operation.[17] A further 1,000 MW of solar PV are expected to be released as tenders in June 2021.[18]

The energy sector occupies a predominant place in the Algerian economy; hydrocarbons alone represent 60 per cent of budget revenues and 98 per cent of export revenues.[19] In 2019, following a decision to halt refining its crude oil products abroad, the country's imports of energy almost doubled compared to 2018, while exports dropped by 8.7 per cent.[10] The level of gas exports is decreasing due to rising domestic consumption and, simultaneously, decreased production, hinting at a reduced reliance on hydrocarbons for revenues in the country's future.[20] Algeria plans to reduce its dependence on hydrocarbons through a diversification of its exports and the development of renewable energy sources.[21] In addition, in July 2020 the President announced the plan to stop all imports of fuels and refined oil products by the first trimester of 2021.[22]

In 2016, 99.4 per cent of the population of Algeria had access to electricity, with approximately 400,000 people living without electricity.[23] By 2017, Algeria had reached 100 per cent electricity access.[24]

Two public companies dominate the energy market of Algeria: Sonatrach for hydrocarbon production and trade, and Sonelgaz, former public monopoly, is in charge of electricity production and distribution, as well as gas distribution. The Renewable Energy and Energy Conservation Directorate at the Ministry of Energy and Mines is responsible for the energy policy and supervises the public energy companies. The Hydrocarbon Regulatory Authority regulates the national oil products market by setting prices. The regulatory authority is the Electricity and Gas Regulation Commission (CREG). Forecasts for electricity demand are established by the state electricity and gas utility company Sonelgaz Subsidiary.

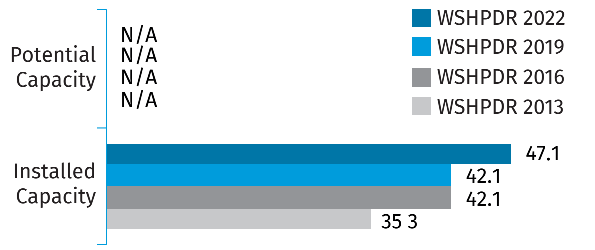
The electricity grid in Algeria has been under stress due to population growth, one-way communication, transmission losses, sudden large amounts of supply and inability of conventional sources to meet the demand.[25] To address the expected increase in electricity demand, the country is actively growing its electricity production. According to the Algerian Programme for the Development of New and Renewable Energies and Energy Efficiency–2030 (PENREE) of 2011, the country aims for an installed capacity of renewable origin of 22,000 MW by 2030, with an intermediary target of 4.5 GW by 2020.[26] The technological developments addressed by this programme include large-scale development of solar PV and wind fields, introduction of biomass fields (waste valuation), cogeneration and geothermal power and, by 2021, also development of solar thermal power (CSP). The long-term goal of this programme is to reach a 20 per cent share of renewable energy in nationwide electricity production by 2030. In contrast, the overall renewable energy target of the country is 27 per cent by 2030.[27] Hydropower is not covered by the PENREE, which favours the development of solar PV, wind power, CSP, cogeneration, biomass and geothermal sources. In fact, in 2014 the Government announced its intention to halt hydropower expansion. More recent plans announce the country's solar PV goal, set at 4 GW by 2024 and 16 GW by 2035.[20]

Electricity tariffs are separated into four categories: 1.77 DZD/kWh (0.013 USD/kWh) for consumption less than 500 kW; 4.17 DZD/kWh (0.031 USD/kWh) for 501–1,000 kW; 4.18 DZD/kWh (0.031 USD/kWh) for 1,001–4,000 kW; and 5.47 DZD/kWh (0.041 USD/kWh) for consumption over 4,000 kW.[28] As of 2021, average electricity tariffs for citizens were 4.01 DZD/kWh (0.030 USD/kWh), which is less than the real price of 5.40 DZD/kWh (0.040 USD/kWh), due to an indirect electricity subsidy.[28]

SMALL HYDROPOWER OVERVIEW

Small hydropower (SHP) in Algeria is defined as any hydropower plant with a capacity of 5 MW to 10 MW, while micro-hydropower is classified as 100 kW – 5 MW and pico-hydropower as plants of less than 100 kW.[29] As of 2020, there was at least 47.1 MW of installed SHP capacity for plants under 10 MW (Table 1). The increase in SHP capacity compared to the *World Small Hydropower Development Report (WSHPDR) 2019* is due to access to more accurate information and the inclusion of the Ighzerouftis plant, which is one of three hydropower plants making up the larger capacity Darguina hydropower plant and which was previously not counted, rather than due to an increase in capacity in recent years (Figure 3). Information on potential SHP capacity in Algeria remains unavailable.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Algeria (MW)**



Source: *WSHPDR 2019*,[29] *WSHPDR 2013*,[30] *WSHPDR 2016*,[31] Mokrane W. & Kettab A.,[32] Bouraiou A. et al.[33]

Note: Data for SHP up to 10 MW.

The difficulty in finding up-to-date information on SHP in Algeria is likely a consequence of the Government's focus on other sources of renewable energy. According to the Ministry of Energy and Mining, 103 hydropower plants have been recorded and more than 50 plants are in operation.[34] However, an academic source cites only 23 hydropower plants as operational, with the Darguina plant, composed of three hydropower plants (Agrioun of 66 MW, Ighzerouftis of 5.2 MW and Irilemda of 24 MW), being the only one that functions regularly.[32] Approximately 21 per cent of the total hydropower installed capacity consists of SHP, but only 5.2 MW of SHP capacity, from the Ighzerouftis plant, is known to be mostly operational (Table 1).

Table 1. **List of Existing SHP Plants in Algeria (Operational and Non-Operational)**

Name	*Status**	*Location*	*Capacity (MW)*	*Head (m)*	*Launch year*
Souk el Djemaa / Michelet	Operational	Tizi Ouzou	8.1	327.0	1949
Ghrib	Operational	Ain Defla	7.0		1942
Gouriet / Maillot-aval	Needs repairs	Bouira	6.4	111.0	1949
Bouhanifia	Non-operational: no water, control table damaged	-	5.7	46.4	1978
Ighzerouftis	Operational	Bejaia	5.2	171.0	1951
Tizi Meden / Boghni-aval	Needs repairs	-	4.5	254.0	1946
Tessala	Non-operational: evacuation passage obstructed	Oran	4.2	-	-
Beni Behdel	Non-operational: no water	Telemcen	3.3	38.5	1948
Ighzerncheb-el	Needs repairs	-	2.7	-	1934
Foum El Gherza	Reformed**	Biskra	350 kVA + 1 MVA	-	1950
Oum Drou / Pontéba	Reformed in 1980**	-		-	1947
Rhumel	Ruined, non-operational	Constantine	-	-	1910
Total			**47.1**		**-**

Source: Mokrane W. and Kettab A.,32 Bouraiou A. et al.,33 Alger, Algérie: documents algériens,35 Khouchane, F.36

Note: *Status of hydropower plants is based on information from 2005. **Reformed plants are those that have been converted into irrigation facilities and no longer supply electricity.

Hydropower, including SHP, as an energy source plays only a marginal role in Algeria due to limited precipitation, high evaporation and competing uses for potable water. The role of hydropower in Algerian electricity production has been in steady decline since 1973, decreasing by 99 per cent from 1971 to 2015.[37] The contribution of hydropower to the total electricity production in 2019 was 0.19 per cent. The highest proportion of electricity production from hydropower was registered in 1973 at 26.80 per cent, and the lowest value ever recorded, before 2019, was 0.21 per cent in 2002.[37]

In 2014, the Government declared its intention to halt operation of electricity production from hydropower plants and to devote existing dams to irrigation and drinking water supply. The Ministry of Energy and Mining stated that the needs of the population for water supply outweighed the electricity generated by the power plants.[38] This sentiment is echoed in the New National Programme for Renewable Energy Development (2015–2030), which excludes hydropower from its roadmap.

RENEWABLE ENERGY POLICY

The renewable electricity goals of Algeria are set out as percentage values of overall electricity generation. Algeria has one of the highest economic solar power potentials in the world, estimated at 13.9 TWh/year for solar PV and 168,972 TWh/year for solar thermal power.[39] The wind power potential in the country is estimated at 35 TWh/year. Algeria has a nationwide environmental strategy, a national plan for environmental action and sustainable development (Plan national d'action environnementale et de développement durable, adopted in 2002), focusing on reducing pollution and noise, preserving biodiversity and natural spaces, training and raising of public awareness on environmental issues.

Algeria has a public procurement tendering process for renewable energy projects, which was defined by Executive Decree No. 17-98 of 26 February 2017.[40] This tendering process is intended to induce competition among investors, maximize the reductions on price per kWh of electricity produced by renewable energy sources and to avoid the risks associated with excessive profits.[34] In 2019, the Government launched tenders for the installation of solar-diesel hybrid mini-grids.[27]

Key laws pertaining to renewable energy include:

- Law No. 99-09 (28 June 1999), which set out to define the contours of renewable energy development, including hydropower;
- Law No. 02-01 (5 February 2002), which provides the legal basis for electricity management, distribution, transportation and production;
- Law No. 04-09 (14 August 2004), which provides the regulatory basis to promote renewable energy and generalize its uses, protect the environment, fight against climate change by limiting greenhouse gas emissions and preserve fossil fuels;
- Law No. 09-09 on the Finance Bill 2010, which created and determined financing for the National Fund for Renewable Energies as 0.5 per cent of oil royalties;
- Law No. 11-11 on the complementary Finance Bill 2011, which created and determined financing for the National Fund for Renewable Energies and Cogeneration as 1 per cent of oil royalties;
- Executive Decree No. 13-218 (18 June 2013) & Executive Decree No. 17-166 (2 May 2017), which determined the feed-in tariff (FIT) incentive measures to promote investment in renewable energy (premiums for the costs of diversification of electricity production from renewable energy).[41]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

In 2013, the Government of Algeria outlined details for a FIT with the aim of speeding up renewable energy development, diversifying the national energy mix and achieving its ambitious renewable energy targets. It also identified the types of technologies that would benefit from the Government aid, including solar PV, CSP, solar thermal power, hydropower, wind power, cogeneration, waste to energy and hybrid power plants. The scheme uses a premium paid per kWh above the base tariff and is expressed as a percentage of the base electricity tariff. The tariff levels vary across technologies as a function of the bonus value attributed, which is calculated based on the technology type and the percentage of the renewable energy source used in electricity generation.[42] The Government bonuses are equivalent to 100 per cent of the price per kWh of electricity for hydropower, 200 per cent for biomass and 300 per cent for waste, wind power and solar thermal power.[42]

Another financing option is the National Fund for Energy Management, Renewable Energies and Cogeneration (FNMEERC or FNER), which finances actions and projects that promote renewable energy and cogeneration. The fund also provides pre-financing for actions under the promotion of renewable energy and cogeneration.[43] Additionally, 1 per cent of oil royalties are also made available for renewable energy investments.[44] Finally, international funding is also an option. Thus, the European Union has a fund of EUR 40 million (USD 47.6 million) dedicated towards the diversification of the Algerian economy, of which EUR 10 million (USD 11.9 million) is earmarked for renewable energy and energy efficiency projects.[44]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The risks of water scarcity and the likelihood of more intense droughts in the region according to future climate scenarios indicate that further SHP development in Algeria is very unlikely. All forms of hydropower in the region are facing stagnation in potential expansion due to geographical and climatic limitations, which include: limited rainfall in the south of the country, hydropower potential concentration in limited spaces, high levels of evaporation and quick evacuation of water resources to the sea. Moreover, the Government intends to halt the production of electricity from hydropower plants, to dedicate the dams producing electricity to irrigation and to providing the population with drinking water.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Many of the hydropower dams in Algeria were built in the colonial era and have been neglected over the past years. This has led to a 99 per cent decrease in the share of hydropower in electricity production in Algeria. The key barriers to SHP development in the country include:

- Access to financing from international banks until 2015 was restricted by the Government, which led to a lack of access to financing institutions;
- Ageing and poor maintenance of existing power plants;
- Weak support for renewable energy technologies and limited knowledge resources available;
- Lack of institutional support and unstable trajectory of renewable energy policies;
- Low prices for conventional energy;
- Lack of local expertise for the realization of SHP projects.[32,33,43]

There are currently no clear enabling factors for SHP development in Algeria.

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Egypt

Nadia Mohamed Eshra, Hydropower Unit, Nile Research Research Institute, National Water Research Center, Ministry of Water Resources and Irrigation; and Davy Rutajoga, International Center on Small Hydro Power (ICSHP)

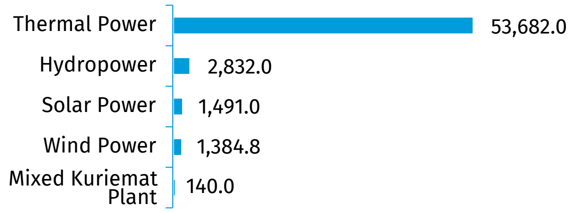
KEY FACTS

Population	105,785,785 (2022)[1]
Area	1,001,450 km^2 [2]
Topography	Egypt is divided into four major parts: the Nile Valley and Delta, which extends from the north of the valley to the Mediterranean Sea; the Western Desert, which extends from the Nile Valley to the border with Libya and from the Mediterranean in the north of Egypt to the southern borders; the Eastern Desert, which extends from the Nile Valley to the Red Sea, the Suez Canal and the Suez Gulf in the east and from Lake Manzala to the Border with Sudan; and the Sinai Peninsula, which extends from the Mediterranean in the north to the Gulf of Aqaba to the east, the Gulf of Suez and the Suez Canal to the west and Ras Mohammed to the south. The highest peak in the country is Mount Catherine, which elevates to 2,642 metres, and the lowest point is the Qattara Depression at 134 metres below sea level.[3,4]
Climate	Egypt has a dry and hot climate. It has a hot and dry season from May to September and a rather mild winter season from November to April. In coastal regions, temperatures can range between the average winter minimum of 14 °C and the average summer maximum of 30 °C. Temperatures also vary considerably in inland desert areas, particularly during the summer months when they can range from 7 °C at night to 43 °C in the morning. In winter months, the fluctuations are less dramatic, though temperatures can reach 0 °C and 18 °C in the morning. Hot wind storms, called Khamsin, sweep across Egypt between March and May carrying sand and dust and can last for days increasing the temperature by 20 °C in as little as two hours.[5]
Climate Change	Egypt has been affected by climate change and is expected to experience further increases in temperature and decreases and variability in rainfall patterns. Temperatures have been observed to increase by 0.1 °C per decade on average between 1901 and 2013 and by 0.53 °C per decade since the 1980s. Warming has been observed to increase more during the summer months than in winter by 0.31 °C and 0.07 °C per decade, respectively, since the 1960s. The daily and nightly minimum temperatures have increased throughout the country as well. Annual total precipitation has been observed to decrease by as much as 22 per cent since the 1980s, with most of the decrease observed during the winter and early spring months.[5]
Rain Pattern	Due to the arid nature of the climate, there is naturally little rainfall throughout the year with most of the rain falling along the coast, particularly in the city of Alexandria. In addition to receiving approximately 200 mm of precipitation per year, Alexandria enjoys high humidity with sea breeze-modulated moisture. The capital city of Cairo, on the other hand, receives approximately 10 mm of precipitation per year, with rainfall decreasing southwards, but enjoys humidity in the summer. The country sometimes experiences extreme sudden rainfall resulting in flash floods.[5]
Hydrology	In Egypt, the main water resource is the Nile River, which provides the country with approximately 97 per cent of the country's water requirements. The Nile is the longest river in the world, with a length of 6,650 kilometres and enters Egypt through the southern borders with Sudan and reaches to the Mediterranean. Other important water systems are the Suez Canal, the Alexandria-Cairo Waterway and Lake Nasser. The country's riverine and coastline basins can be divided into four main parts: the North Interior Basin, which covers 52 per cent of the country in the east and south-east; the Central Nile Basin, which covers 33 per cent of the country as a broad north-south strip; the Mediterranean Coast Basin, which covers 6 per cent of the country; and the North-East Coast Basin, which covers 8 per cent of the country along the Red Sea coast.[6,7]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in Egypt are thermal power, hydropower, solar power and wind power. In 2019/2020, electricity production in the country amounted to 197,357 GWh, of which thermal power accounted for approximately 88 per cent, hydropower for less than 8 per cent, solar power for slightly more than 2 per cent, wind power for 2 per cent and isolated units and power purchased from independent power producers (IPP) accounting for less than 1 per cent (Figure 1).[8]

Figure 1. **Annual Electricity Generation by Source in Egypt in 2019/2020 (GWh)**

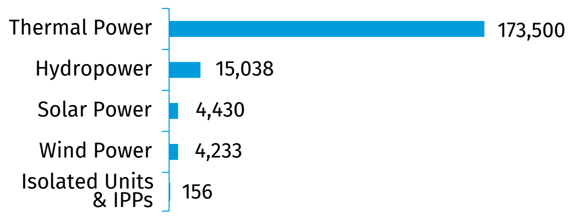


Source: EEHC[8]

In 2016, in order to meet an increasing energy demand, the Government of Egypt launched the Integrated Sustainable Energy Strategy (ISES) to 2035, an energy diversification strategy that aims to guarantee safe and stable energy supply in the country. The ISES also aims to ensure an increase of the share of renewable energy in the country's generation mix as well as to establish Egypt as a focal point of the energy map linking Africa, Europe and Asia by strengthening the interconnection of the electricity network both in the Arab region and beyond.[9]

There are six currently operational hydropower plants in Egypt, amounting to approximately 2,832 MW of installed capacity, or a 5 per cent share of the total installed capacity of approximately 59,530 MW. Thermal power, solar power and wind power account for approximately 90 per cent, 2.5 per cent and 2.5 per cent of the total installed capacity, respectively (Figure 2). Hydropower accounts for almost 5 per cent, while the joint solar/natural gas Kuriemat plant accounts for less than 1 per cent of the total installed capacity.[8]

Figure 2. **Installed Electricity Capacity by Source in Egypt in 2019/2020 (MW)**



Source: EEHC[8]

The main institutions defining energy policy in Egypt are the Ministry of Electricity and Renewable Energy (MOERE) and the Supreme Council for Energy (SCE). The MOERE regulates the generation, transmission and distribution of electricity in the country, while the Electric Utility and Consumer Protection Regulatory Agency (EgyptERA) is responsible for licensing and sector monitoring. The Egyptian Electricity Holding Company (EEHC), with its 16 companies, is responsible for system studies and planning for grid expansion and power plant projects. In terms of generation, subsidiaries are divided by regions of responsibility with the addition of the Hydro Plants Generation Company. The Egyptian Electricity Transmission Company (EETC) is responsible for the countrywide transmission of electricity to regional and local distributors with distribution companies depending on the region.[9]

The Government of Egypt has been making progress towards the development of nuclear power as part of the ISES, with plans to launch the first nuclear power plant in the country already underway as of 2021. Regulation of the nuclear power sector is to be undertaken by the Nuclear and Radiological Regulatory Authority (NRRA). The first studies on nuclear capabilities in Egypt were conducted by the Nuclear Power Plants Authority (NPPA) with technical support from the International Atomic Energy Agency (IAEA). In order to respond to the growing energy demand and accommodate the future nuclear power plants, the Government of Egypt drafted a new law, the new Electricity Law of 2015.[9]

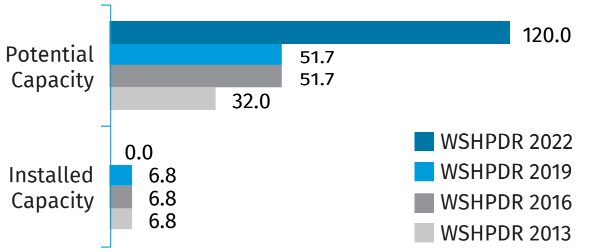
Under the New Electricity Law of 2015, the EETC is to be separated from the EEHC into an independent transmission system operator (TSO) and new companies are required to obtain a permanent licence from EgyptERA before carrying out any electricity-related activity.[10]

The electricity tariffs for residential users in Egypt in 2020/2021 ranged from USD 0.075 per kWh for low consumption (less than 100 kWh/month) to USD 2.260 per kWh for high consumption (more than 1,000 kWh/month).[8] The electrification rate in the country was 100 per cent in 2019.[11]

SMALL HYDROPOWER SECTOR OVERVIEW

In Egypt, there is no official definition of small hydropower (SHP). For this chapter, SHP will be defined as hydropower plants with a capacity of up to 10 MW. Currently, there are no operational SHP plants in Egypt, whereas the total potential capacity is estimated to be at least 120 MW.[12] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, potential capacity increased based on more accurate data and installed capacity decreased taking into account the non-operational status of the plants (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Egypt (MW)**



Source: Eshra,[12] *WSHPDR 2019*,[13] *WSHPDR 2016*,[14] *WSHPDR 2013*[15]

Table 1. **List of Selected Potential Small Hydropower Projects in Egypt**

Name	*Average potential capacity (MW)*
Damietta	9.00
Rosetta	5.30
Zefta	3.53
El-Tawfeki	2.02
El-Menofi	1.83
Tamia	1.10
El-Azab	0.80
Mokthalat	0.50

Source: Eshra et al.[16]

In Egypt, SHP started in the 1890s with the launch of the 1.1 MW Tamia plant and the 0.8 MW El-Azab plant. They were followed by the 5 MW Old Nag Hamadi plant installed in Upper Egypt and after a long period of time by the 5 MW El-Lahoun plant in Fayum Oasis. All these plants stopped operating due to different problems.

In 2019, studies by Eshra et al. identified eight potential sites for the development of SHP in the Nile Delta and Fayum Oasis (Table 1). The sites have an estimated 24.08 MW of combined potential capacity and an estimated generation capacity of 15.6 GWh.[16] A 2019 study of the same area by the Hydroelectric Power Plant Executive Authority (HPPEA) identified at least seven potential sites for the development of SHP. The Ministry of Electricity plans to develop sites with an estimated potential capacity of 2–5 MW. The construction of the plants is to be funded by the German development agency KfW with a budget of approximately USD 32,620,950. As of 2020, the project had yet to be validated by the Ministry of Irrigation due to concerns over the environmental and social impact of the project in the region.[17]

RENEWABLE ENERGY POLICY

The Government of Egypt issued an environmental law in 1994 to accord special attention to environmental concerns in its energy policy. Following the adoption of this law, the Egyptian Environmental Affairs Agency (EEAA) was created to develop, monitor and implement pilot energy projects. The EEAA is endowed with authority to review and approve all environmental impact assessments (EIA) that must be submitted before licensing power plants in Egypt.[9]

In 2015, partly due to a need for a more competitive and less centralized system, the Government of Egypt adopted the new Electricity Law 87/2015, which emphasized the importance of renewable energy. This new law came after the adoption of the Renewable Energy Law (REL) 203/2014, which aimed to encourage the private sector to invest in renewable energy. Provisions made to specifically address the private sector and facilitate its involvement in renewable energy are outlined in Article 2 of the REL, which includes feed-in tariffs (FITs), competitive bids and independent power production through third party access.[10]

In 2014, the Government of Egypt announced a FIT programme aiming to add approximately 4.3 GW of generation capacity from renewable energy sources. Divided into two rounds, the FIT programme was introduced by the Cabinet Decrees No. 1947 of 2014 and No. 2532 of 2016 for rounds 1 and 2, respectively. These rounds set tariffs for the electricity generated from wind and solar power to be applicable for two years for round 1 and one year and a half for round 2 on power purchase agreements (PPAs) concluded after the issuance of decrees. The PPAs should not exceed 20 years for wind power projects and 25 years for solar power projects.[10]

Under the competitive bid scheme outlined in the REL, the New and Renewable Energy Authority (NREA) issues tenders to private companies that are to install renewable energy power plants, including SHP plants, via an Engineering, Procurement and Construction (EPC) contract. The electricity produced shall be sold to ETTC at a price suggested by Egypt ERA and approved by the Cabinet.[10]

Though there are no government incentives that specifically target hydropower, the African Development Bank's Electricity and Green Growth Support Program (EGGSP) to the Government of Egypt offered a loan of approximately USD 244,698,750 to the country to support its renewable energy and climate change mitigation initiatives. This loan could apply to the hydropower development efforts currently undertaken by the HPPEA.[18]

As part of the Government of Egypt's support for the development of renewable energy, the new Investment Law No. 72 of 2017 was adopted to offer incentives and tax reductions for investors in renewable energy projects. The incentives for renewable energy projects include flat custom duty rates on all machines and equipment for renewable energy projects, registration fee waivers, discounts for project investments, value-added tax (VAT) exemptions for renewable electricity activities and reductions for imported renewable energy equipment, flat electricity rates until 2025, waste-to-energy tariffs and a net-metering scheme. There were also plans for lifting electricity subsidies adopted by the Prime Ministerial Decree 1257/2014, which was delayed due to the COVID-19 pandemic and instead expected to be achieved in the fiscal year 2024/2025.[10]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The development of new SHP projects in Egypt is hampered mainly by:

- The lack of government interest and the favouring of a renewable energy policy based largely on wind and solar energy. Without any financial incentives being given specifically to SHP, it will be difficult to attract investment over other more favourable renewable energy options;
- More studies of the SHP potential should be carried out. The lack of interest in SHP stems from a general consensus that some 85 per cent of the Nile River has already been developed for hydropower, meaning that the NREA stands to make better marginal gains and garner better financial support by looking into other untapped non-hydropower resources. Nonetheless, this assessment is largely based on a perspective from large hydropower projects. More accurate studies on SHP may reveal the existence of significant undeveloped potential.

Enablers for SHP development in Egypt include:

- The Government's strategy to position Egypt as an energy hub that connects Africa, Asia and Europe involves the increase in the share of renewable energy in the generation mix;
- Relatively recent laws and policies that centre renewable energy could lead the Government to consider alternative ways of generating electricity, including SHP;
- The relatively recent emphasis on renewable energy incentives as well as encouragement of international investors and the private sector's involvement in the energy sector could attract actors interested in SHP development;
- Significant SHP potential remains undeveloped and is especially high in parts of the country with a developed irrigation network and various types of hydraulic constructions.

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Morocco

Bilal Amjad, International Center on Small Hydro Power (ICSHP)

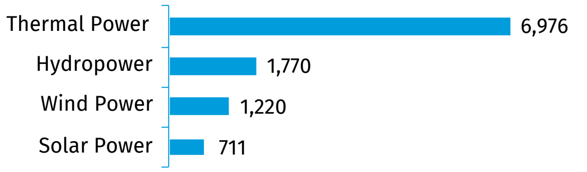
KEY FACTS

Population	36,280,141 (2021)[1]
Area	446,550 km^2 [2]
Topography	Morocco has four mountain ranges. The Rif Chain extends in an arc parallel to the Atlantic Ocean in the west. The High Atlas, approximately 80 kilometres in breadth, extends eastwards for 700 kilometres. Mount Toubkal is the highest point of the massif (4,165 metres). The Middle Atlas and Anti Atlas are the other two massifs. Beyond the chains of the Atlas, lie the pre-Saharan and Saharan zones of the country, where large hamadas form rugged desert plateaus covered with pebbles or dunes.[2]
Climate	Morocco is characterized by a diverse climate. In the northern coastal regions, temperatures are generally mild, reaching an average of 14 °C. In the highlands and mountains, temperatures are usually below 0 °C but can reach -20 °C, causing frost on the plateaus and significant snowfall in the mountains. Summers are hot and dry with mean temperatures of 24 °C on the coast and above 35 °C, sometimes exceeding 40 °C, in the country's interior.[2]
Climate Change	The climate in Morocco is very vulnerable to the global temperature rise, particularly on the north-eastern coast where the sea level is predicted to rise by up to 59 centimetres by the end of the 21st century, causing flooding and storm surges. According to the National Meteorological Directorate of Morocco, by 2100 the average temperature can increase by 2–5 °C and rainfall can decline by 20–30 per cent. These shifts will have a big impact on the country's water resources, leading to less precipitation and more frequent droughts.[3] The year 2020 was recorded among the country's four driest years since 1981. The annual mean temperature across the country in 2020 was 1.4 °C warmer than during the period between 1981 and 2010.[4]
Rain Pattern	In the north, winters are generally wet and mild, with the cumulative annual rainfall decreasing from north to south (from 1,000 to 200 mm/year) and peaking in the mountainous regions (2,000 mm/year in the Rif and 1,800 mm/year in the Middle Atlas). In the southern regions, rainfall is very rare and irregular. Most regions on average receive less than 130 mm of rain per year, with the exception of rare humid, tropical air surges, which give rise to rainfall in the form of showers.[2]
Hydrology	The most important and permanent rivers of Northern Africa are in Morocco: Loukos (100 km), Sebou (500 km), Bouregreg (250 km), Moulouya (450 km), Daraa (1,200 km), Oum Rbia (600 km), Tensift (270 km) and Ziz (270 km).[2]

ELECTRICITY SECTOR OVERVIEW

Compared with other countries in the Middle East and Northern Africa, Morocco is characterized by a lack of conventional hydrocarbon resources and a high reliance on energy imports.[5] In 2019 electricity generation in Morocco totalled 40,348 GWh, of which approximately 67 per cent was from coal, almost 12 per cent from natural gas and wind power each, 4 per cent from hydropower and solar power each and the rest from other sources (Figure 1).[6] National electricity production in 2019 accounted for nearly 99 per cent of total electricity demand, while the remainder was imported through interconnections with neighbouring countries including Spain and Algeria. The same year 1,453 GWh of electricity was exported, which was more than three times higher than the year before.[6]

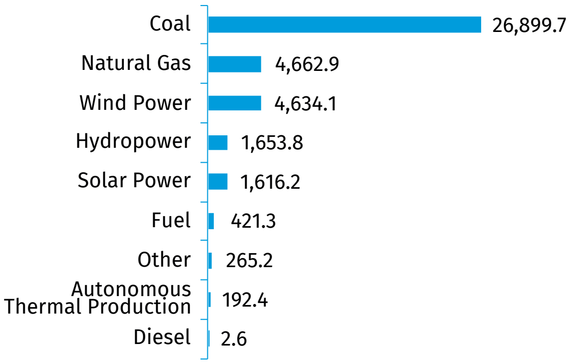
Figure 1. **Annual Electricity Generation by Source in Morocco in 2019 (GWh)**



Source: ONEE[6]

In 2019, the installed electricity capacity of Morocco was 10,677 MW. Of the total, thermal power plants accounted for 65 per cent, hydropower plants for 17 per cent, wind power plants for 11 per cent and solar power plants for 7 per cent (Figure 2).[7]

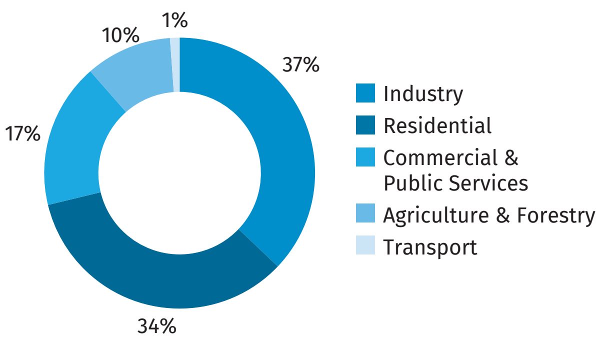
Figure 2. **Installed Electricity Capacity by Source in Morocco in 2019 (MW)**



Source: ONEE[7]

Total energy consumption in Morocco has significantly increased in recent years. Thus, in 2019, it grew by 9 per cent compared to 2018, driven by growth in electricity consumption, which increased by 15 per cent due to the progress achieved in rural electrification and economic growth.[6,8] Between 2015 and 2030, primary energy consumption in the country is projected to double and electricity demand is expected to increase 2.5 times.[5] Overall, since 1990, the electricity sector of Morocco has developed impressively by diversifying generation, improving security of supply and reaching almost universal access to electricity.[9] Currently, electricity consumption in the country is dominated by the industrial and residential sectors (Figure 3).[10]

Figure 3. **Electricity Consumption by Sector in Morocco in 2018 (%)**



Source: IEA[10]

The electricity sector in Morocco is dominated by the state-owned operator, the National Office of Electricity and Potable Water (ONEE). It has the status of the single buyer of electricity produced in the country, except for generation from renewable sources, for which a specific law allows private-to-private electricity transactions.[11] ONEE owns the entire transmission network and much of the distribution network and can give concessions to private operators through purchase guarantees.[12] As the sole buyer, ONEE supplies the national market through its own plants, those of independent power producers (IPPs) and through a number of private industrial producers. IPPs include some of the largest plants in the country such as Jorf Lasfar Energy Company (JLEC) (coal), Safi Energy Company (SAFIEC) (coal) and Electrical Energy Company of Tahaddart (gas, combined cycle).[13]

The Moroccan electricity grid is linked with the Spanish grid through a 400 kV double underwater alternating current line under the Strait of Gibraltar with a capacity of 1.4 GW. Since 1988, Morocco has also had a synchronous interconnection with the Algerian grid via a 400 kV transmission line. Initially its capacity was 1.2 GW, but increased to 1.7 GW with the installation of a second and third lines in 2009.[13,14]

Until 1995, only 18 per cent of the Moroccan population had access to electricity and over the last 20 years approximately 12 million citizens received access through the Global Rural Electrification Programme. Today the electrification rate in Morocco is close to 100 per cent. The country adopted a utility-lead electrification programme where ONEE was responsible for achieving rural and remote area electrification targets. Strong political support, involvement of local stakeholders, funding and engagement of the private sector have enabled ONEE to provide sustainable electricity from solar power to 200,000 households in remote rural communities.[6] In 2019, 373 villages were electrified, providing electricity access to 10,113 households.[6,11]

Electricity tariffs are not uniform in Morocco. The customers are subject to tariffs that are set and reviewed by the Ministry of General Affairs and Governance, on the advice of an Inter-Ministerial Pricing Committee. The latest review process was undertaken between 2014 and 2017. The tariffs are applied to distribution companies by ONEE and to final costumers by distribution companies and depend on the consumer category.[15] Tariffs applied to households are incremental based on monthly consumption, ranging from 0.10 USD/kWh for consumption below 100 kWh to 0.18 USD/kWh for consumption above 500 kWh.[16] A bi-hourly tariff aiming to reduce the evening peak demand is implemented by ONEE on the national level to all low-voltage consumers (including domestic, industrial and agricultural users) with monthly electricity consumption exceeding 500 kWh.[17] Electricity consumption for public lighting and by administration buildings is subject to a fixed price tariff.[15] Rural populations are subjected by ONEE to pricing based on a prepaid meter. These rates, depending on the type of use and consumption bracket, fluctuate between 0.12 USD/kWh and 0.20 USD/kWh.[18]

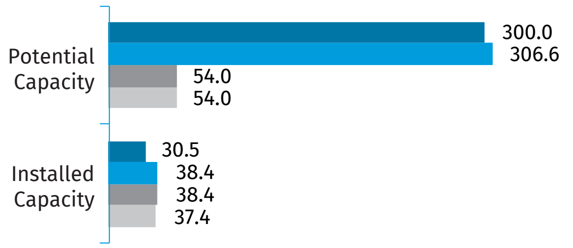
Multiple changes have been experienced in the electricity sector of Morocco over the past years due to the competitive production and commercialization of electricity from renewable energy sources, for very high-voltage/high-voltage/medium-voltage (MV) customers, in accordance with Law 13-09 on renewable energy. The creation of a regulatory agency, National Energy Regulatory Agency (ANRE), was announced by Law 48-15 adopted in 2016.[19] ANRE is responsible for ensuring equal access to the national electricity grid, setting tariffs for the use of the transmission and transportation grids, approving rules and tariffs for access to electricity interconnections and accompanying the implementation of the national energy transition strategy.[20]

SMALL HYDROPOWER SECTOR OVERVIEW

In accordance with the classification established by the International Union of Electric Power Distributors, four categories of hydropower plants are distinguished in Morocco: pico- (less than 20 kW), micro- (20–500 kW), mini- (500–2 MW) and small hydropower plants (SHP) (2–10 MW).[21] The current chapter uses the definition of SHP as all hydropower plants up to 10 MW.

As of 2021, the total installed capacity of SHP up to 10 MW in Morocco was estimated at 30.5 MW (Table 1).[22,23,24] The decrease compared to the *World Small Hydropower Development Report (WSHPDR) 2019* is due to access to more accurate data (Figure 4). The potential capacity is estimated at 300 MW, which is also slightly lower than reported in the *WSHPDR 2019*, with the decrease also being based on a more accurate estimate.[25]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Morocco (MW)**



Source: ONEE,[22,25] Saad Alami,[23] Government of Morocco,[24] *WSHPDR 2013*,[26] *WSHPDR 2016*,[27] *WSHPDR 2019*[28]

Note: Data for SHP up to 10 MW.

Table 1. **List of Existing Small Hydropower Plants in Morocco**

Name	*Installed capacity (MW)*	*Launch year*
Masser	0.10	2008
Askaw	0.20	2002
Oum Er Rbia	0.22	2004
Sefrou	0.26	1929
Taza Rass El Oued	0.64	1929
Flilou	1.60	2015 (1933)
Fes Aval	1.89	1934
Taurart	2.00	1954
Bouareg	6.40	1969
Kasba Zidania	7.20	1935
Mansour Eddahbi	10.00	1972
Total	**30.51**	

Source: ONEE,[22] Saad Alami,[23] Government of Morocco[24]

In the 1990s, the Development Centre of Renewable Energies (CDER) identified 153 potential SHP sites in the regions of Haouuz, Khenifra and Chefchaouen. The combined potential capacity of these sites was estimated at 6.7 MW, with individual sites having capacities up to 500 kW.[29] More recently, the ONEE has identified 125 sites suitable for SHP development in the basins of the Oum-Errabia, Sebou and Moulouya Rivers, with individual capacities ranging between 100 kW and 1.5 MW and a total potential capacity estimated at 300 MW.[25] Due to the unavailability of lists of the sites identified in these studies, it is not possible to establish whether any overlaps between the two exist, therefore, the current chapter uses the findings of the more recent study as the SHP potential estimate.

Large hydropower has played an important role in the country's energy mix since the 1960s, however, a large share of the available potential has been developed. Therefore, as part of the Government's strategy to promote renewable energy sources by 2030, the main focus for hydropower lies with pumped-storage hydropower as well as small-scale projects.[30] Furthermore, many studies show concern about the impact of climate change on the availability of water in Morocco, which may affect the SHP potential in future.[31] Under Law 13-09 on renewable energy, a number of hydropower projects were approved for development by the private sector.[30] One of these projects consisted of the rehabilitation of an SHP plant at Flilou by the private company Energie Terre; the project was commissioned in 2015.[23] A further 11 SHP projects up to 10 MW with a combined capacity of 61.5 MW are currently under development (Table 2) as well as 10 other projects with capacities between 11.7 MW and 30 MW.[32]

Table 2. **List of Small Hydropower Projects under Development in Morocco**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Developer*	*Planned launch year*
Sidi Chahed	Oued Mikkès, Mèknes	1.3	–	Voltalia Maroc	2019
Sidi Said	Commune Zayda, Midelt	1.89	Reservoir	Energie J2 Terre	2019
Tameslouhte	Lalla Takerkoust Dam, Marrakech-Safi	2.5	Reservoir	Energie J2 Terre	2021
Sidi Driss	Oued Lakhdar	3.5	–	Energie J2 Terre	2019
Machraa SFA	Machraâ Benabbou	6.0	–	Energie J2 Terre	2022
Merija	Machraâ Benabbou	6.0		Energie J2 Terre	2022
Wirgane	Lalla Takerkoust Dam, Marrakech-Safi	6.6	Reservoir	Energie J2 Terre	2020

Name	*Location*	*Capacity (MW)*	*Plant type*	*Developer*	*Planned launch year*
Oued Za	Commune Oued Za, Province de Taourirt	6.7	–	Energie J2 Terre	2022
L'Oum Er-Rbia	Beni Mellal-Khénifra	7.2	–	Voltalia Maroc	2021
Bougemaz	Beni Mellal-Khénifra	9.8	–	Voltalia Maroc	2021
Asfalou	Asfalou Dam, Taounate	10.0	Reservoir	SGTM	2019
Total		**66.35**			

Source: MEME[32]

ONEE has also initiated a project for the rehabilitation of existing hydropower capacities with an estimated cost of approximately EUR 35 million (USD 41 million) to be financed through a loan from the European Bank for Reconstruction and Development (EBRD). The project includes rehabilitation of such SHP plants as Taurart, Bouareg, Taza, Askaw, Sefrou, Tabant and Fes Aval as well as a study of the generation potential of the country's hydropower fleet, including the impacts of the climate crisis.[33]

RENEWABLE ENERGY POLICY

In 2009, Morocco adopted a National Energy Strategy (NES) as a roadmap for the transformation of the energy sector towards greater sustainability, efficiency and financial stability. The NES sets five key objectives for the country's energy policy, including: 1) diversification of the energy mix, 2) national resource development including renewable energy resources, 3) improvement of energy efficiency, 4) integration with international and regional (European and African) energy markets and 5) industrial integration of renewable energy and green technologies.[34]

The climate action strategy of Morocco is defined by the Climate Change Policy (March 2014), the National Sustainable Development Strategy (November 2017) and the Nationally Determined Contribution (NDC) to the United Nations Framework Convention on Climate Change (UNFCCC) (2016). On 21 September 2016, Morocco signed the Paris Agreement, committing to cut its greenhouse gas emissions by 17 per cent by 2030, with an additional reduction of 25 per cent on the condition of international support.[34] The country intends to raise the share of renewable energy sources in its total installed capacity to 52 per cent by 2030. The 2016–2030 period will therefore see the development of 10,100 MW of renewable energy, with solar power to account for 20 per cent of the 2030 energy mix, wind power for 20 per cent and hydropower for 12 per cent. Moreover, Morocco is committed to achieving 15–20 per cent energy saving by 2030 through energy efficiency programmes for the industrial and transport sectors. These strategies are aiming to ensure the country's energy independence, reduce its greenhouse gas emissions and diversify the energy mix.[9,31]

Since 2008, Morocco has experienced a period of rapid change in its power sector, focusing on harnessing its huge renewable energy potential. In order to ensure meeting the energy transition targets, the renewable energy sector of Morocco has been undergoing liberalization. In 2008, Law 16-08 raised the threshold for the allowed self-generation capacity from 10 MW to 50 MW and allowed operators to sell ONEE their occasional surpluses. Law 13-09 promulgated in 2010 set out the legislative framework for the promotion of renewable energy sources. The law allowed renewable electricity producers to feed electricity into the medium- and high-voltage grid or sell it to users. It also removed the power limitations for certain types of energy and introduced three licensing regimes for renewable energy projects depending on the size: a free regime for capacities below 20 kW; a declaration regime for capacities between 20 kW and 2 MW; and an authorization regime for projects above 2 MW. This law was amended by Law 58-15 and Law 13-09, allowing independent renewable energy producers (including hydropower plants above 30 MW) to sell electricity surpluses to ONEE or a distribution system operator. These measures will enable clients from the tertiary and residential sectors to develop renewable energy capacities and feed any excess production into the low-voltage network.[31] At the moment of writing of the current chapter, two further draft laws were under consideration — draft Law 40-19 and a draft law on self-generation. These aim to improve the legislative and regulatory framework for renewable energy and self-generation projects.[35]

In line with the national energy transition strategy, in 2021 the Ministry of Energy, Mines and Environment agreed to collaborate with the International Renewable Energy Agency (IRENA) on accelerating the energy transition and advancing the national green hydrogen economy, as Morocco intends to become a major producer and exporter of green hydrogen.[36]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are multiple barriers to SHP development in Morocco. Some of the most important ones are the following:

- SHP projects are less attractive in comparison to other renewable energy sources such as solar and wind power, for which the investment returns are higher;
- Lack of public awareness about the benefits of SHP;
- Low level of interest in research and development (R&D) projects on SHP at universities;
- Impact of the climate crisis on the availability of water resources.

Despite the above barriers, opportunities for SHP development in Morocco exist due to the following factors:

- Availability of data on potential sites for SHP development;

- The policy, legislative and regulatory frameworks favour renewable energy projects, including hydropower.

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Sudan

International Center on Small Hydro Power (ICSHP)

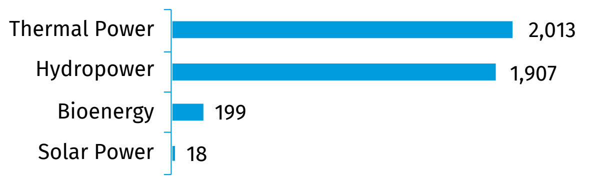
KEY FACTS

Population	43,849,269 (2020)[1]
Area	1,849,234 km^2[2]
Topography	Sudan is a large country mainly composed of plains and plateaus drained by the Nile River and its tributaries. Northern Sudan is largely covered with a sandy desert diversified by steep-sided granite hills. South-central Sudan is marked by isolated hills that culminate in the Nuba Mountains. The north-east of the country borders the Red Sea, while the Darfur Plateau in the west carries the Marrah Mountains culminating at 3,042 metres above sea level.[3]
Climate	Sudan has a hot, desert climate with strong winds prevailing all year long in the north, bringing dry and cool air in the winter. In the summer, temperatures often exceed 43 °C in the north. the southern regions are slightly cooler. The mean annual temperatures in the country are between 26 °C and 32 °C.[3,4]
Climate Change	Sudan has been experiencing the effects of global warming including increasingly frequent extreme climatic events. Droughts are more common and rainfall has become even more erratic. Temperatures were observed to increase by 0.2-0.4 °C per decade between 1960 and 2009, while precipitation decreased by 20-30 mm per decade in the same time frame. By 2050, temperatures are projected to increase by as much as 3 °C and the Red Sea levels are expected to increase by 30-50 cm.[5]
Rain Pattern	Sudan has a rainy season from March to October, with most of the rainfall occurring between June and September. Rainfall in the country is generally unpredictable and unreliable, with the northern regions experiencing little to no rainfall (less than 50 mm of rainfall). Central regions receive between 200 mm and 700 mm of rainfall a year, while the southern regions enjoy more rainfall at over 1,500 mm per year.[4]
Hydrology	Sudan enjoys considerable water resources primarily from the Nile River and its tributaries, as all rivers and streams of the country drain into or towards the Nile. The White Nile and the Blue Nile enter the country from the south-east and join at Khartoum and after the confluence flow northwards as the Nile.[4]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in Sudan are hydropower and non-renewable thermal power. Of the total 16,846 GWh generated in Sudan in 2019, hydropower accounted for almost 61 per cent and thermal power for 39 per cent. Bioenergy and solar power accounted for 109 GWh and 22 GWh, or 0.7 per cent and 0.1 per cent, respectively, of the total electricity generation (Figure 1).[6]

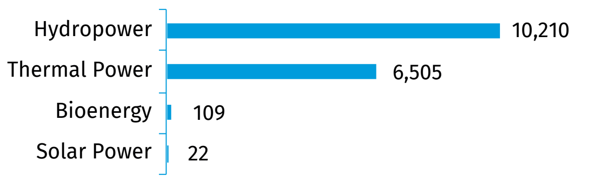
Figure 1. **Annual Electricity Generation by Source in Sudan in 2019 (GWh)**



Source: IRENA[6]

Sudan has one of the largest power sectors in Sub-Saharan Africa and was one of the largest crude oil producers in the region until 2011 when South Sudan gained independence. In addition, South Sudan also retained custody of most of the hydropower plants that once served the former unified country. This meant a significantly reduced installed capacity for the Republic of Sudan.[7,8]

Figure 2. **Installed Electricity Capacity by Source in Sudan in 2020 (MW)**

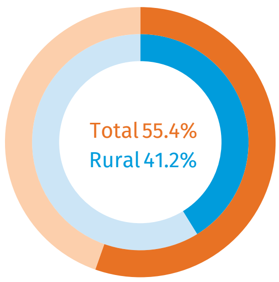


Source: IRENA[6]

In 2020, Sudan had a total installed electricity capacity of 4,137 MW, of which non-renewable thermal energy, hydropower and bioenergy represented almost 49 per cent, 46 per cent and 5 per cent, respectively. Solar power accounted for 18 MW, or 0.4 per cent, of the total installed capacity (Figure 2).[6]

In 2020, Sudan had a total electrification rate of 55 per cent, with a rural electrification rate of 41 per cent (Figure 3).[9,10]

Figure 3. **Electrification Rate in Sudan in 2020 (%)**



Source: World Bank[9,10]

The energy sector in Sudan is overseen by the Ministry of Energy and Petroleum (MoEP) and is composed of five major companies: the Sudan Electricity Holding Company (SEHC), the Sudan Electricity Transmission Company (SETC), the Sudan Electricity Distribution Company (SEDC), the Sudan Thermal Power Generation Company (STPG) and the Sudan Hydro and Renewable Energy Company (SHREC). These companies do not have financial autonomy and are integrated into the MoEP. The MoEP also oversees the Electricity Regulation Authority (ERA), which regulates the country's electricity sector.[7]

The electricity generated in Sudan is mostly publicly-owned with the exception of some thermal generation in isolated grids and emergency powership rentals operated by independent power producer (IPPs). With most of the crude oil reserves owned by South Sudan after the separation, Sudan has had to adapt to meet its ever-growing electricity demand. This includes international agreements for the importation of electricity from neighbouring countries.[7]

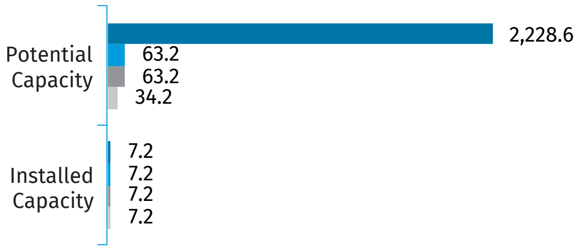
Sudan has one of the lowest electricity tariffs in the region. In January 2021, the average tariff was 0.023 USD/kWh, with the bill collection rate standing at 93 per cent.[7]

SMALL HYDROPOWER SECTOR OVERVIEW

The Government of Sudan defines small hydropower (SHP) as hydropower plants with an installed capacity between 500 kW and 5 MW. Mini-hydropower is defined as 50–500 kW plants and micro-hydropower is below 50 kW. For the purpose of this chapter, the up to 10 MW definition of SHP will be used.

There is currently one SHP plant in Sudan, the El-Girba 2, which has an installed capacity of 7.2 MW (Figure 4).[11] The estimated technical SHP potential in Sudan is 2,228.6 MW, including 123.2 MW from 352 sites of 0.1–1 MW capacity and 2,105.4 MW from 435 sites of 1–10 MW capacity.[12] The increase in SHP potential compared to the *World Small Hydropower Development Report (WSHPDR) 2019,* is due to the more recently obtained data from a study on SHP potential in Sub-Saharan Africa. The installed capacity has remained unchanged (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Sudan (MW)**



Source: Korkovelos et al.,[12] *WSHPDR 2019,*[13] *WSHPDR 2016,*[14] *WSHPDR 2013*[15]

RENEWABLE ENERGY POLICY

Sudan does not have an integrated renewable energy policy document. However, the country has been making efforts to formulate plans to develop its renewable energy potential. While hydropower represents approximately 60 per cent of the total electricity generated in the country, the Government of Sudan is committed to further integrate other renewable energy sources into the generation mix. Specifically, the Government aims to have at least 50 per cent of electricity generation from other renewable energy sources than hydropower by 2031.[16]

The Government also adopted a National Energy Efficiency Action Plan (NEEAP) in 2013 after becoming a member of the Regional Center for Renewable Energy and Energy Efficiency (RCREEE). The set aims include achieving universal electrification, doubling the rate of energy efficiency improvement and ensuring access to modern and reliable electricity by 2030. The Government is also committed to developing the country's SHP potential for a total installed grid-connected capacity of 50 MW by 2030.[16,17]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP plants are regulated by the same legislation as larger hydropower projects. The main legislation and regulation documents in Sudan concerning hydropower projects are:

- The Water Resources Act (1995);
- The National Water Act (2007);
- The Sudan Electricity Act (2001).

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The development of new SHP projects in Sudan is hampered mainly by:

- Lack of a comprehensive renewable energy policy that addresses SHP;
- The Government's focus on larger hydropower to solve the country's electrification issues;
- Irregularity of rainfall patterns, which affects SHP development, further exacerbated by climate change;
- Lack of comprehensive mapping of renewable energy sources in key areas;
- Most of the electricity generation is state-owned, which might discourage potential private sector investors.

Enablers for the development of SHP projects include:

- The abundant water resources in the country due to the location in the Nile Basin. There is great potential for SHP development;
- The Government's commitment to developing renewable energy sources and the inclusion of SHP in 2030 energy development goals.

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Tunisia

Nouri Chtourou, Emna Omri, Rim Jemli and Soukaina Fersi, University of Sfax

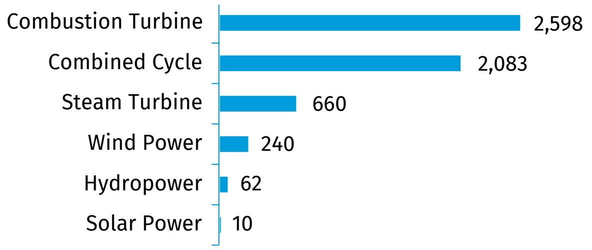
KEY FACTS

Population	11,708,370 (2020)[1]
Area	155,360 km^2 [2]
Topography	The country is divided into three distinct regions. The northern region is characterized by mountains, cork forests and grasslands. The central region is a semi-arid steppe plateau with olive groves. The southern region, which stretches from the border with Algeria to the Mediterranean, contains date palm oases and saline lakes. The extreme south of Tunisia merges into the Sahara Desert. The highest point, Jebel Chambi (1,544 metres), is located near the city of Kasserine.[2]
Climate	The north of Tunisia benefits from a Mediterranean climate, the centre and the Gulf of Gabes have a semi-arid climate and the rest of the country has a desert climate.[2]
Climate Change	The National Institute of Meteorology of Tunisia projects that, based on the climate scenario “RCP4.5”, climate in the country by 2050 and 2100 will be characterized by an increase in average annual temperatures and a decrease in annual precipitation. The rise in temperatures will vary between 1 °C and 1. 8°C by 2050 and between 2 °C and 3 °C by the end of the 21st century. In addition, there will be a decrease in annual precipitation of between 5 and 10 per cent by 2050, with a further decrease of between 5 and 20 per cent by 2100.[3]
Rain Pattern	Rainfall is between 400 mm/year in the north of the country and 1,500 mm/year in the far northwest. The central region of Tunisia receives 200–400 mm/year, while in the southern regions of the country rainfall is rare, averaging approximately 50–200 mm/year.[4]
Hydrology	The most important river system in Tunisia, the Medjerda (460 km long), rises in Algeria and drains into the Gulf of Tunis. It is the only river in the country that flows perennially; other watercourses fill only seasonally. In the central Tunisian steppes, after heavy rains, occasional waterways flow southwards out of the Dorsale Mountains, but evaporate in salt flats without reaching the sea.[4]

ELECTRICITY SECTOR OVERVIEW

The electricity sector in Tunisia is characterized by a steady rise in demand and a decrease in the availability of national resources. In 1999, net imports of electricity stood at 6,978 GWh. Since 1999, there has been a steady increase in electricity imports, reaching 72,106 GWh in 2018.[5] Electricity generation rose from 19,245 GWh in 2018 to 20,217 GWh in 2019. Of this total, 17,007 GWh was provided by the Tunisian Company of Electricity and Gas (STEG), 3,071 GWh by the Carthage Power Company (CPC) and 139 GWh by autoproducers.[6] The electricity sector primarily uses natural gas, which accounts for more than 90 per cent of electricity production (Figure 1).

Figure 1. **Annual Electricity Generation by Source in Tunisia in 2019 (GWh)**

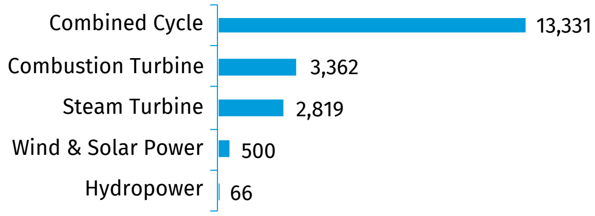


Source: STEG[6]

Note: Includes generation by STEG and CPC only.

Installed electricity capacity in Tunisia increased from 5,076 MW in 2018 to 5,653 MW in 2019. The national generation capacity is composed of steam turbines, gas turbines and combined cycle power plants. The share of wind power, solar photovoltaics (PV) and hydropower in the country’s energy mix is very insignificant compared to the available potential of those three resources (Figure 2).[6]

Figure 2. **Installed Electricity Capacity by Source in Tunisia in 2019 (MW)**



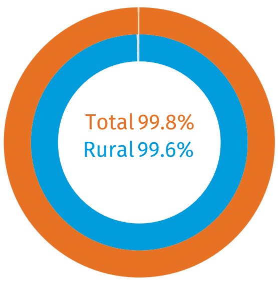
Source: STEG[6]

Note: Does not include installed capacity for hydropower plants not connected to the national grid (approximately 5 MW).

Tunisia is heavily dependent on fossil fuel imports, in particular, imports of natural gas from Algeria. The continuous volatility of fossil fuel prices and the increase of net energy imports have had significant negative repercussions for the country's economy, including massive outflows of foreign currency and an increase in public spending. An important feature of the energy sector of Tunisia are the vast subsidies allocated to conventional energy in order to keep the tariffs for hydrocarbons and electricity at a level that would not deteriorate the purchasing power of the poorest groups of the population. In fact, the budget allocated to energy subsidies tripled between 2017 and 2020, increasing from TND 650 million (approximately USD 239 million) in 2017 to TND 1,880 million (approximately USD 693 million) in 2020.[7]

In 2019, the total length of medium-voltage (MV) and low-voltage (LV) lines in the electricity transmission network of Tunisia reached 180,419 km, with 60,966 km of MV lines and 119,453 km of LV lines. This represented a combined extension of an additional 5,030 km (a 2.9 per cent increase) relative to 2018. The length of the high-voltage network reached 6,985 km in 2019.[6] In 2019, the total national electrification rate was at 99.8 per cent, while the rural electrification rate stood at 99.6 per cent (Figure 3).[8]

Figure 3. **Electrification Rate in Tunisia in 2020 (%)**



Source: STEG[8]

The main actor in the country's electricity sector is the state-owned STEG, which is responsible for electricity generation and distribution. The Tunisian electricity market is partially liberalized. Following Decree 1996-1125 (1996) and Law 96-27 (1996), private generation of electricity is possible through concessions granted by state authorities. This also includes off-grid sources.

Electricity prices at all levels are set at the end of each fiscal year by the Ministry of Industry in collaboration with relevant Government agencies such as the General Direction for Energy (DGE), the Tunisian Enterprise of Petroleum Activities (ETAP), the Tunisian Company of Refining Industries (STIR), the Ministry of Commerce and the Ministry of Finance. Prices are influenced by numerous factors, including the international prices of crude oil and gas, the financial situation of the STEG, ETAP and STIR, as well as the level of Government subsidies. After the STEG's price policies have been approved by the Government, the Ministry of Industry sets consumer gas and electricity prices.

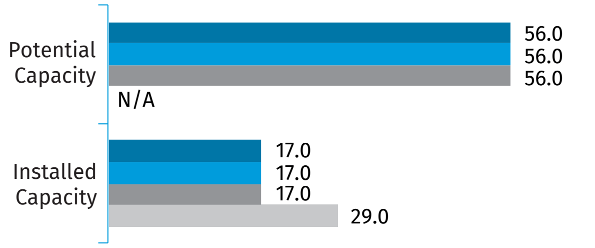
Since June 2019, STEG has applied new electricity tariffs. For low-voltage consumers, tariffs are assigned based on monthly consumption for households and other consumers and according to time slots in the case of pumping for agricultural irrigation. For the category that consumes between 1 and 100 kWh of electricity per month, the tariffs differ between households and other consumers. For households that consume between 1 and 50 kWh/month, the price per kWh is TND 0.062 (USD 0.023). For households that consume between 51 and 100 kWh/month, the price per kWh is fixed at TND 0.096 (USD 0.036). For consumers exceeding 100 kWh/month, the price per kWh varies between TND 0.176 (USD 0.065) and TND 0.414 (USD 0.15) for households and between TND 0.195 (USD 0.072) and TND 0.391 (USD 0.15) for other consumers. For the category of agricultural irrigation, the price varies between TND 0.106 (USD 0.039) and TND 0.391 (USD 0.15) according to three time slots (day, night and evening peak).

The tariffs applied to MV and HV consumers are assigned according to the type of consumer and four time slots (day, summer morning peak, evening peak and night). For MV tariffs, the prices per kWh are assigned according to four categories: regular category (TND 0.251 (USD 0.092)), time slots category (TND 0.188–0.366 (USD 0.069–0.130)), pumping water for agricultural irrigation (TND 0.138–0.195 (USD 0.050–0.071)) and relief supply (TND 0.200–0.407 (USD 0.073–0.150)). For HV tariffs, the prices per kWh are categorized into two types: time slots category (TND 0.160–0.309 (USD 0.058–0.110)) and relief supply (TND 0.168–0.350 (USD 0.061–0.130)). It should be noted that the above-mentioned tariffs do not include the Value Added Tax rate of 19 per cent and the municipal surcharge of TND 0.005/kWh (0.002 USD/kWh).[9]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in Tunisia. For the purposes of this chapter, the definition of up to 10 MW will be used. The installed capacity of SHP up to 10 MW in Tunisia is 16.98 MW, while the potential capacity is estimated at 55.98 MW, indicating that approximately 30 per cent of the known potential has been developed.[10,11] There has been no change in either installed SHP capacity or estimated potential capacity since the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Tunisia (MW)**



Source: STEG,[10] *WSHPDR 2016*,[11] *WSHPDR 2013*,[12] *WSHPDR 2019*[13]

Note: Data for SHP up to 10 MW.

Tunisia has a great theoretical hydropower generation potential, which in the mid-1990s was estimated at 1,000 GWh/year, but the technically feasible generation potential is only approximately 250 GWh/year.[14] There is a total installed hydropower capacity of 67 MW in the country, of which 62 MW is connected to the national grid and approximately 5 MW is isolated. The oldest hydropower plant is located in Nebeur (Kef Governorate, northern Tunisia). Built in 1956, it is a reservoir-type plant with a capacity of 13.2 MW. In total, there are seven hydropower plants in Tunisia; of these, the hydropower plant of Sejnane with a capacity of 0.6 MW, is currently not operational (Table 1). Many of the existing hydropower plants were built during the period of French colonization and are predominantly located in the north-western region. The total annual electricity generation of these plants ranges between 50 and 160 GWh.[13]

Table 1. **List of Existing Hydropower Plants in Tunisia**

Hydropower plant	*Capacity (MW)*	*Operator*	*Launch year*
Sidi-Salem	36.00	-	-
Nebeur	13.20	-	-
Fernana	8.50+1.20	Neyrpic	1958-1962
El Aroussia	4.80	Franco Tosi	1956
Bouhertma	1.20+0.62	Alsthom	2003
Sejnane*	0.60	-	-
Kessab	0.66	-	1969
Total	**66.18**		

Source: STEG[10]

Note: *Out of operation.

The two large hydropower plants of Sidi Salem and Nebeur have capacities of 36 MW and 13.2 MW, respectively. Therefore, there are currently five SHP plants in Tunisia, at El Aroussia, Sejnane, Kessab, Fernana and Bouhertma. Their overall installed capacity stands at 16.98 MW.

The renewable energy (RE) strategy in Tunisia is focused on solar and wind power, which receive the support of the Government. Conversely, little interest is given to hydropower, either from the Government or private investors. This would explain the stagnation of hydropower installed capacity in comparison to other sources of RE in Tunisia.

However, in 2019, the National Company for the Exploitation and Distribution of Water (SONEDE) of Tunisia invited bids in separate tenders from qualified contractors to design, equip and build two micro-hydropower plants. These two projects are to be financed by the French Development Agency (AFD). They are located on the water supply network in Montfleury in the north-eastern Governorate of Tunis and at the upper reservoir of Lahirech in the north-western Governorate of Jendouba. The contracts will imply studies of the projects, supply and installation, testing and commissioning of electro-mechanical and electrical equipment, associated civil works, connection to the MV network of STEG, training of technical staff and after-sales service (including provision of spare parts).[15] The status of these two projects is currently unknown. Additional potential SHP sites identified in previous studies are displayed in Table 2.

Table 2. **List of Potential Small Hydropower Sites in Tunisia**

Location	*Potential capacity (MW)*
Barbara	3.00
Sidi Saad	1.75*
Bouhertma	1.20
Sejnane	1.00
Siliana	0.85
Bejaoua	0.75
Khanguet Zezia	0.65
Nebhana	0.50
Medjez el Bab	0.25
Total	**9.95**

Source: *WSHPDR 2019*[13]

Note: *Unconfirmed data.

RENEWABLE ENERGY POLICY

For more than three decades, Tunisia has pursued a proactive policy of energy management. The main axes of this policy are energy efficiency and the development of RE. Despite all the efforts made, the energy situation is characterized by a growing deficit in the energy balance, an increase in the energy bill and an increased dependence on fossil fuels.

In order to address the challenges facing the Tunisian energy system, the Government has committed to a policy of energy transition in the medium and long term. The important elements of this policy have included the creation of the Energy Transition Fund (FTE) in 2013 and the promulgation of the Law on Electricity Production from Renewable Energy Sources in 2015. In the field of energy management, the National Agency for Energy Management (ANME) is the main actor for the implementation of state policy. The ANME has a fundamental role in the energy transition process. The flagship initiatives carried out by the ANME have focused mainly on:

- Elaboration of strategic studies, especially in the areas of rational energy use, RE development and mitigation of greenhouse gas (GHG) emissions;
- Realization of sectoral studies on the energy mix of electricity production and on the Tunisian Solar Plan;
- Conducting specific studies on the financing of energy management initiatives, in particular the restructuring of the National Energy Management Fund (FNME) and the operationalization of the FTE;
- A study on the institutional reform of the ANME in order to enable the Agency to achieve its strategic objectives and to operate in an optimal and efficient manner.

The studies carried out by the ANME represent an essential tool for informing decision-makers on the prospects and challenges of the energy transition in Tunisia. These studies outline the strategic goals and the institutional, regulatory and financial measures necessary to achieve them. The main goals to achieve by 2030 are as follows:

- Reduce primary energy demand by 30 per cent compared to the trend scenario;
- Increase the share of RE in electricity production to 30 per cent;
- Reduce carbon intensity of the energy sector by 46 per cent compared to 2010.[16]

As part of the energy transition plan, Tunisia is striving to engage with international frameworks and agreements on implementing green and sustainable energy policies, including the Paris Agreement of 2015. In September 2015, Tunisia submitted its first National Determined Contribution (NDC), with the objective of reducing the carbon intensity of all sectors of the economy by 41 per cent in 2030 relative to 2010. Energy is placed at the heart of sectoral priorities in the field of emissions reduction, with a significant contribution of 75 per cent in the overall mitigation target of the Tunisian NDC. Energy efficiency and RE are the two main levers to achieve the objective assigned to the energy sector, which aims to reduce carbon intensity by 46 per cent in 2030 compared to the 2010 level. The capacity of the RE sector of Tunisia currently stands at 312 MW (6 per cent of all energy capacity), not including an additional 5 MW of hydropower not connected to the national grid. The aim for the share of RE in the electricity sector is to reach 30 per cent in 2030 (with an installed capacity of 3,815 MW). RE investments in Tunisia are mainly focused on the solar and wind power projects.[17]

The ANME has undertaken the necessary work to meet the requirements of a low-carbon energy transition in accordance with the recommendations of the Paris Agreement. In particular, the ANME has produced a database of GHG emissions of the energy sector over the period of 1980–2012 and an estimate for the period of 2013–2019. In addition, at the beginning of 2020, the ANME carried out a new inventory of GHG emissions in the energy sector covering the period of 2010–2019. The preparation of this inventory is based on the new methodology of the Intergovernmental Panel on Climate Change (IPCC). Furthermore, in 2020, an update of the NDC and elaboration of a National Low Carbon Strategy (NLCS) were initiated. These two elements represent the main instruments of the Tunisian climate policy and an opportunity to accelerate the energy transition and to address both the climate and the energy security issues. Their development defined medium and long-term goals for a changing energy landscape and low-carbon development to meet the energy, climate and socio-economic challenges for 2030 and 2050. Finally, the ANME has developed a monitoring methodology for the NDC in the energy sector, which should enable the assessment of progress towards the achievement of the mitigation target in the energy sector as defined by the NDC. In addition, it serves well to meet the transparency requirements of Article 13 of the Paris Agreement.[18]

In 2019 and within the framework of a partnership with the African Development Bank (AfDB), Tunisia made plans to create the "Fund Establishment and Fund Management Services for A Multi-Investor Equity/Quasi-equity Climate Impact Fund Financing Sustainable Energy Projects and Companies in Tunisia". In this regard, in 2019 the Fund of Deposits and Consignments (CDC) and the subsidiary of STEG, STEG-ER, launched a call for expressions of interest addressed at investment fund management companies and/or consortiums for the creation, development and management of an investment fund dedicated to the equity/quasi-equity financing of projects with a high environmental impact and oriented towards the energy transition of Tunisia.[19] This Fund aims to promote local currency financing in Tunisian dinars where most appropriate. The AfDB is collaborating with the CDC and STEG-ER in raising financing from a variety of international sources as part of a wider effort to catalyze investment in sustainable energy across the continent. The estimated duration of services is between July 2019 and December 2030. It is important to highlight that the CDC and STEG-ER retain the right to own up to 40 per cent of the fund management company.[20]

The main laws and decrees that regulate the RE sector in Tunisia are the following:

- Law No. 12 of 11 May 2015, which liberalizes the production and export of electricity from RE;
- Law of Investment No. 2016-71 of 30 September 2016 and Government decree No. 2017-389 of 9 March 2017, which provide financial and institutional incentives for investment in the RE sector;
- Law No. 2017-8 of 14 February 2017, which provides tax incentives for investments realized in the RE sector.[21]

The distribution and transportation of electricity remain exclusively the prerogative of STEG, which also sets the purchasing and transportation tariffs. Therefore, investors who self-produce their electricity using RE (and, therefore, are self-consumers) must first sign a contract for the sale of excess electricity produced from RE sources to STEG. Hence, STEG must buy back the surplus according to the established feed-in tariffs (FITs).

The FITs and transmission tariffs for electricity produced by self-consumers or for self-consumption were set by the decision of the Minister of Energy, Mines and Energy Transition of 27 May 2020 (Table 3).[22] The high-voltage (HV) electricity transmission tariff of 0.025 TND/kWh (0.009 USD/kWh; excluding VAT) is only applied for self-consumer organizations benefiting from the right to sell electricity produced from RE and whose production units are connected to the HV network.[23] The tariffs set by this decision apply to the electricity produced from 1 June 2020 on the entire territory of the country.[22]

Table 3. **FITs on Surplus Renewable Energy Electricity Sold by Self-Consumers in Tunisia**

Period	*Price (TND/kWh (USD/kWh))**
Day	0.073 (0.026)
Summer morning peak	0.087 (0.032)
Peak evening	0.077 (0.028)
Night	0.069 (0.025)

Source: STEG[24]

Note: *Excluding VAT of 19 per cent.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

SHP implementation in Tunisia is hindered by several barriers:

- Technical barriers such as: limited access to appropriate technologies in the mini-, micro- and pico-hydropower categories, which pose specific technical challenges; and limited specialization to undertake feasibility studies;
- Energy/electricity sector barriers: mainly the high competition with other RE technologies as well as the maturation of solar and wind power technologies;
- Political barriers: there is limited commitment on the part of the Government to encourage and promote SHP technologies;
- Financial barriers: there is limited participation from the private sector, in part due to a lack of stable funding for SHP and in part due to better investment opportunities with other RE sources.[13]

Recently, Tunisia has experienced a marked increase in rainfall, especially between the years 2018 and 2019. This in turn has led to increased river discharge and a considerable improvement in dam reservoir levels. As a result, electricity generation by the Tunisian hydropower sector as a whole rose to almost 66 GWh in 2019, a 299.4 per cent increase over the previous year. If these weather patterns continue, SHP could become a more promising source of RE for Tunisia in the future.

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1.4. Southern Africa

Countries: Botswana, Eswatini, Lesotho, Namibia, South Africa

INTRODUCTION TO THE REGION

South Africa is the largest economy in the region by a wide margin, with a robust electricity sector. Thermal power, mainly from coal-fired power plants, accounted for approximately 82 per cent of installed capacity and 86 per cent of generation in 2021. The country also operates the region's only nuclear power plant with an installed capacity of 1,940 MW. The country has some of the highest rates of electricity access in the region, but rural areas still lag behind the rest of the country. Imports of electricity from South Africa contribute a significant share of the electricity supply of all other countries in the region, with Lesotho importing over 50 per cent and Eswatini nearly 80 per cent of their electricity from South Africa. Regional electricity generation is dominated by state-owned companies. The public utility of South Africa ESKOM, the single-largest regional power producer, operates over 89 per cent of the generating capacity of South Africa while the rest is operated by independent power producers (IPPs) and municipalities.

Hydropower development in the region displays some notable characteristics tied to the regional dependence on electricity imports from South Africa. In South Africa itself, hydropower plays a supplementary role, accounting for only 6 per cent of capacity and 3 per cent of generation as of 2021. At the same time, hydropower accounts for the majority of all domestic electricity generation in Namibia and Eswatini and over 99 per cent in Lesotho, with Namibia additionally investing heavily in solar power. Thus, these three countries have adopted a strategy of sourcing their domestic electricity generation from renewable energy while relying on imported electricity from thermal power for the bulk of their energy needs. Botswana is likewise dependent on electricity imports to a significant extent, but has no domestic hydropower capacity due to climactic and topographical factors and has instead opted to source its domestic generation from coal-fired and diesel-fired power plants.

An overview of the electricity sectors of the countries in the Southern Africa region is provided in Table 1.

Table 1. **Overview of Southern Africa**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Botswana	2	62	62	893	3,332	0	0
Eswatini	1	77	70	109	293	69	227
Lesotho	2	45	32	77	389	76	392
Namibia	3	55	35	684	1,818	351	1,288
South Africa	60	85	79	57,214	214,926	3,427	6,182
Total	-	-	-	**58,977**	-	**3,922**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in Southern Africa varies across countries. Botswana, Eswatini and Namibia do not have a local definition of SHP, in Lesotho SHP is defined as hydropower plants of up to 10 MW, while in South Africa the up to 40 MW definition is used alongside the up to 10 MW definition. A comparison of installed and potential capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Southern Africa (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Botswana	N/A	0.0	N/A	0.0	1.0
Eswatini	N/A	8.2	16.2	8.2	16.2
Lesotho	Up to 10 MW	3.8	38.2	3.8	38.2
Namibia	N/A	0.1	120.0	0.1	120.0
South Africa	Up to 40 MW	N/A	N/A	42.0	247.0
Total	-	-	-	**54.1**	**422.4**

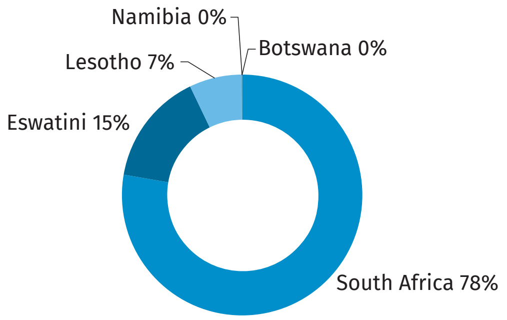
Source: *WSHPDR 2022*[1]

The installed capacity of SHP up to 10 MW in Southern Africa is 54.1 MW, while the estimated potential capacity is 422.4 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has increased by 8 per cent, while the estimated potential capacity has remained the same.

The role of SHP in the Southern Africa region varies from country to country and is heavily influenced by economic and environmental factors. Botswana and Namibia both have little to no existing SHP capacity due to low population densities and semi-arid conditions predominating across much of their territory. South Africa operates the majority of the region's installed SHP capacity, but the country's SHP capacity is low relative to that of large hydropower and other energy sources and plays a minor role in the domestic electricity supply. SHP provides a substantial share of the total installed electricity capacities of Eswatini and Lesotho, with both countries possessing significant hydropower resources, but the role of SHP in these two countries should not be overstated due to their heavy reliance on electricity imports. The overwhelming share of SHP potential in the region (87 per cent) is represented by South Africa and Namibia. Significant potential may additionally exist in Botswana but has not been confirmed in detailed studies.

The national share of regional installed SHP capacity by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

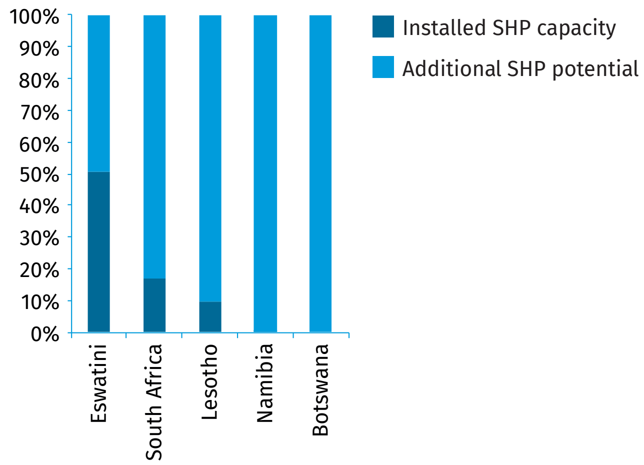
Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Southern Africa (%)**



Source: *WSHPDR 2022*[1]

Note: Botswana not included due to absence of installed SHP capacity.

Figure 2. **Utilized Small Hydropower Potential up to 10 MW by Country in Southern Africa (%)**



Source: *WSHPDR 2022*[1]

There are no SHP plants in **Botswana**. Hydropower potential in the country is low due to prevailing topographical features and climatic conditions. One study has identified an SHP potential of approximately 1 MW in the northern part of the country, while a more recent, continent-scale study suggested a significantly higher theoretical potential of 1,289 MW for SHP up to 10 MW. However, this latter figure is likely an overestimate and further detailed studies are necessary that account for current climatic conditions and economic constraints.

The installed capacity of SHP up to 10 MW in **Eswatini** is 8.2 MW from four SHP plants, of which one has been decommissioned but is still technically operational. Most of the existing plants were constructed between 1950 and 1990 and no new SHP plants have been commissioned in recent years, with hydropower development focusing on larger projects. Undeveloped SHP potential was estimated at 8 MW in 2001, with an array of potential micro-, mini- and small hydropower sites identified in subsequent studies. The total SHP potential of the country following the up to 10 MW definition, including existing capacities, is thus estimated at 16.2 MW, indicating that approximately 51 per cent has been developed.

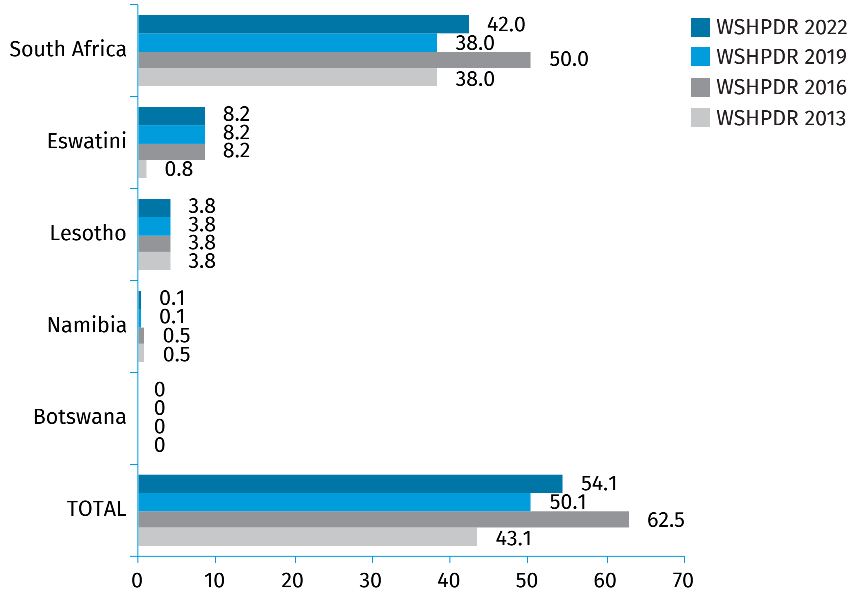
Lesotho has an installed SHP capacity of 3.8 MW from five SHP plants, of which only two plants with a total capacity of 2.2 MW are operational. The potential capacity of the country, including existing plants, is estimated at 38.2 MW, indicating that 10 per cent of SHP potential up to 10 MW has been developed. No new SHP plants have been built in the last two decades, but plans for the rehabilitation of currently non-operational plants are in place.

Namibia has a single SHP plant with an installed capacity of 0.05 MW. The role of SHP in the country's electricity sector is negligible. Namibia has several perennial rivers, one of which hosts a large hydropower plant, but smaller streams appropriate for SHP development are rare as the country is one of the driest and water-stressed in the region and globally. Plans have been proposed to develop 13 SHP plants on the Orange River with a total capacity of 120 MW.

In **South Africa**, the installed capacity of SHP up to 10 MW stood at 42 MW as of 2021, while potential capacity was estimated at 247 MW, indicating that 17 per cent of the known potential is currently utilized. A large number of SHP plants exists throughout the country, but the operational capacity has fluctuated considerably over the past 60–70 years as old plants have been decommissioned and new ones constructed in their place. Many operational plants are located on private land and are not connected to any private grid, supplying power for self-consumption to commercial entities such as mines and resorts. The SHP sector in the country has seen an increase in activity starting with 2009 following decades of neglect, in part due to the promotion of renewable energy sources under the REIPPP programme implemented by the Government. Several new SHP plants have been constructed in recent years.

Changes in the installed SHP capacities of countries in the Southern Africa region compared to the previous editions of the *World Small Hydropower Development Report (WSHPDR)* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower up to 10 MW from *WSHPDR 2013* to *WSHPDR 2022* by Country in Southern Africa (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

Climate Change and Small Hydropower

In South Africa, the Western Cape region is expected to see a 13 per cent decline in the average annual runoff, while the eastern coast will experience an increased risk of flooding. Countries in the Zambezi River basin, which includes Namibia and Botswana, have already experienced climate change, especially rainfall variability. The projected continuous rise in evaporation and evapotranspiration due to the increased temperatures could spur higher water stress in the region. However, the impacts on runoff are yet uncertain.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In **Botswana**, SHP development is hindered by existing climatic and topographic conditions, which include the flat nature of the terrain with few perennial rivers, as well as by lack of detailed studies of SHP potential.

Eswatini has considerable hydropower resources including untapped SHP potential, but development of SHP in the country is hindered by limited private sector investment, reliability issues with the national electricity grid, and lack of detailed data on sites in need of refurbishment. However, there is renewed interest in SHP development in the country, particularly in the rehabilitation of old SHP plants. This interest is driven in part by rising electricity prices and has resulted in several recent studies assessing undeveloped SHP potential.

The SHP potential of **Lesotho** is likewise significant, relative to the size of the country and existing electricity demand. However, a variety of factors have prevented this potential from being realized, including lack of government planning and local technical capacity for SHP development, difficulty of access to potential sites and small size of the electricity market in the country. Additionally, existing hydropower resources are increasingly stressed by climate change.

Namibia has significant undeveloped SHP potential, but economic factors and a lack of a legislative framework for SHP development have hindered its realization. An additional barrier is that most significant hydropower resources are shared with neighbouring countries, while inland hydropower resources are rare and the country's water resources in general are stressed by variability induced by climate change. At the same time, government policy is broadly supportive of renewable energy development and provides incentives in the form of renewable energy funds and feed-in tariffs.

The main barriers to SHP development in **South Africa** are the lengthy and complicated licensing procedures as well as a lack of interest in financing SHP projects on the part of local banks. Nonetheless, SHP is considered an attractive option for electricity producers in the country alongside other renewable energy sources due to the high relative cost of power generation from fossil fuels. Additional incentivization of SHP is not required and a well-established bidding process for RES projects (REIPPP) has been in place for over a decade. Considerable undeveloped SHP potential remains in the country, particularly on existing water supply infrastructure, which South Africa has in abundance.

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Botswana

Mareledi Gina Maswabi, Department of Energy

KEY FACTS

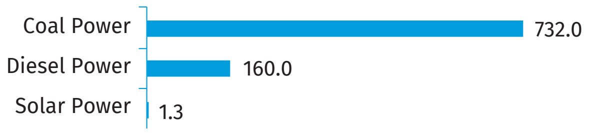
Population	2,351,625 (2020)[1]
Area	581,730 km² [2]
Topography	Botswana is generally flat with a mean altitude of 1,000 metres. A large plateau of approximately 1,200 metres in height divides the country into two distinct topographical regions. The eastern region is hilly, with bushland and grasslands, whereas to the west lies the Okavango Swamps and the Kalahari Desert.[3]
Climate	Botswana has a semi-arid and subtropical climate with both wet and dry conditions. The semi-arid condition makes the climate highly dynamic with variable and sometimes extreme weather. During the dry season, which lasts from April to October in the south and up to November in the northern part, day temperatures can rise to 38 °C and higher, reaching 44 °C on rare occasions in some areas. The winters are dry and clear-skied. Since there is no cloud cover, the air is warmer during the daytime and colder at night. Early mornings have temperature averages 4 °C.[4]
Climate Change	Botswana is vulnerable to climate change, particularly to increasing temperatures and fluctuating rain patterns. Studies show decreased rainfall throughout the country, associated with decreases in the number of rainy days.[5]
Rain Pattern	In Botswana, rains are experienced during summer, peaking in January and February. Rainfall appears to be highly regional, unpredictable and sporadic. The south-west experiences the least average annual rainfall of less than 220 mm, while the north-eastern region receives the highest rainfall averaging 500 mm. The mean annual rainfall ranges from a maximum of over 650 mm in the extreme north-east of the Chobe District to a low of less than 250 mm in the extreme south-west of the Kgalagadi District. There is little to no rain during winter and humidity is low, typically 20–40 per cent. Annual rainfall trends indicate a general decline.[4,6]
Hydrology	Due to its low topography, the country's water storage capacity is one of the lowest in the region. Water sources consist mainly of surface water from rivers of varying sizes, pans and dams, and deep water in aquifers, some of which are non-rechargeable and fossil in nature.[7] The Chobe River in the north, the Limpopo in the south-east and the Okavango in the north-west are the only year-round sources of surface water. These perennial rivers are shared with neighbouring countries. The shared river basins include Okavango, Zambezi, Orange-Senqu and Shashe-Limpopo.[8] The total dam-water capacity is currently estimated at 800 mm³, while the underground capacity (developed resources) is at 131,290 m³/day. The lack of further economical dam sites in Botswana represents a cap in water storage capacity. Waste water makes up 16 per cent of all water supplies, of which just 20 per cent is reused.

ELECTRICITY SECTOR OVERVIEW

Botswana is endowed with abundant coal and solar energy resources. Coal reserves are estimated at approximately 212 billion tons and approximately 2.7 trillion cubic metres of coal-bed methane (CBM) have also been recorded.[9] Besides coal and CBM, there are no other proven reserves of possible fossil fuel resources such as natural gas or oil. There is an abundance of solar power potential countrywide as well as a significant potential from wind power and bioenergy, which is underdeveloped. Countrywide average direct normal irradiance (DNI) solar potential is 6.83 kWh/m² per day with the highest annual sums in the south-western parts of the country.[10] The lowest values are in the extreme eastern parts; however, these remain on a par with the highest resource areas of Europe. Annual energy production from wind is estimated at above 4.5 GWh per year. The theoretical potential of biomass is estimated at 32 million GJ per year, with the use of livestock residues (manure) offering the highest practical opportunity for energy production. Municipal solid waste can also contribute significantly towards energy generation at the city level.

Electricity consumption in Botswana stood at approximately 4,505 GWh per year in 2020 and is expected to reach 8,637 GWh per year by 2040 driven by economic growth.[11] Demand stands at 600 MW and installed capacity stands at 893.3 MW, with 732 MW coming from coal (Morupule A and B power plants), 160 MW from diesel (Orapa and Matshelagabedi plants) and 1.3 MW from solar power (Figure 1).[11,13] There is still a significant amount of power imported from neighbouring countries to augment local supply since the coal-fired plants are not generating to maximum capacity. Morupule A, with a total capacity of 132 MW and a lifetime ending in 2026, is expected to supply 1,020 GWh when fully operational, but on average only delivers approximately 843 GWh of electricity per year.[12] Morupule B, with an installed capacity of 600 MW (4 units of 150 MW) is under remedial works and has not worked to its full capacity since its commissioning in 2014. To date, Morupule B provides approximately 2,299.5 GWh per year and is expected to operate fully by the year 2023. The Orapa (90 MW) and Matshelagabedi (70 MW) emergency diesel-peaking plants were commissioned in 2010 and 2011, respectively. They were intended to mitigate the possible risk of supply shortfall during the Morupule B power plant remedial works period.

Figure 1. **Installed Electricity Capacity by Source in Botswana in 2020 (MW)**



Source: BCP[13]

At the moment, the share of renewable energy in electricity generation is very insignificant and precise figures on solar power generation in the country are not reported on systematically. In 2019, total electricity generation stood at 3,332 GWh, of which solar power accounted for less than 0.2 per cent (Figure 2).

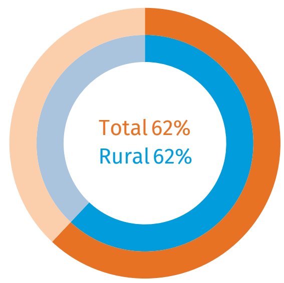
Figure 2. **Annual Electricity Generation by Source in Botswana in 2019 (GWh)**

Source: IRENA[14]

The overall national electricity access rate is 62 per cent, with 61.56 per cent in urban areas and 61.60 per cent in rural areas (Figure 3).[9] The Government has committed to an ambitious target of achieving 100 per cent national electricity access by 2030.[15] To meet this target, it is expected that 30 per cent of the rural population's access will be provided by solar home systems and a further 7 per cent of the rural population will be served by mini-grids.[16]

Having depended on imports from neighbouring countries for a long time, Botswana is now striving for self-sufficiency in electricity. Since 2016, most of the country's electricity needs are met by local generation through a state-owned entity, namely, Botswana Power Corporation (BPC), mainly from the two coal power plants (Morupule A and Morupule B), augmented by the two diesel-operated peaking plants (Matshelagabedi and Orapa). BPC is responsible for the generation, transmission and distribution of electricity and currently holds the sole rights to transmission and distribution. BPC is also involved in the promotion of the involvement of individual power producers (IPPs) in the field of renewable energy.

Figure 3. **Electrification Rate in Botswana in 2021 (%)**



Source: Ministry of Mineral Resources, Green Technology and Energy Security9

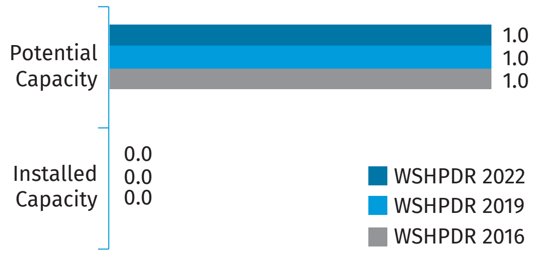
The Electricity Supply (Amendment) Act of 2007 allows for IPPs to partake in generation even though, to date, there is no IPPs playing a role in the electricity sector of Botswana.[17] In accordance with the Electricity Supply Act and the Botswana Power Corporation Act, Botswana Energy Regulatory Authority (BERA) regulates the production, transmission, distribution and selling of electricity through the BERA Act of 2016.[18] An Integrated Resource Plan (IRP) of 2020 outlines the country's power build programme for a period of 40 years, taking into account generation from various energy sources.[19]

The Southern African Development Community (SADC) has developed a competitive electricity market for the region since 2004. Regional electricity prices are analyzed as part of the Southern African Power Pool (SAPP) Plan, which seeks to identify a core set of generation and transmission investments of regional significance that can provide adequate electricity supply and support enhanced integration and power trade in the region. In line with this, Botswana aims to diversify and increase economic development by securing competitive, cost-reflective and sustainable electricity prices. As at June 2020, the price of electricity in Botswana was 0.109 USD/kWh and 0.130 USD/kWh for households and businesses, respectively.[20]

SMALL HYDROPOWER SECTOR OVERVIEW

Due to its aridity, Botswana does not have any hydropower plants and there is no advocacy for hydropower development in the existing energy policies and plans. The potential SHP capacity of the country is estimated at 1 MW.[21] No changes in the small hydropower (SHP) sector in the country have taken place since the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2016/2019/2022 in Botswana (MW)**



Source: Jonker Klunne,[21] Korkovelos et al.,[22] *WSHPDR 2016*,[23] *WSHPDR 2019*[24]

It has been reported that there is potential for a 1 MW site in the northern part of the country.[21] A more recent geospatial study showed a significantly higher theoretical potential: 70.4 MW for mini-hydropower (0.1–1 MW) and 1,218.6 MW for SHP (1.01–10 MW).[22] This study was undertaken at a continental scale and likely overestimates the amount of water resources available under the current climatic conditions. A thorough, more focused research on hydropower potential in Botswana is needed and would help inform policy making around the development of hydropower in the country.

The current backup power plants in Botswana are relying on diesel fuel and replacing these with cleaner options such as hydropower would assist the country meet its climate and sustainable development goals while ensuring reliable electricity supply. However, lack of hydrological resources in the country is a key barrier and disincentive.

RENEWABLE ENERGY POLICY

The Ministry of Mineral Resources, Green Technology and Energy Security, through the Department of Energy is the coordinator of all development activities in the sector. The Government of Botswana recognizes the importance of limiting activities that could harm the environment as presented in Vision 2036 and the Eleventh National Development Plan (2017–2023).[25,26] The Nationally Determined Contributions (NDC) of Botswana presents a commitment of 15 per cent greenhouse gas emissions reduction by 2030, using 2010 as a baseline.[27] The NDC recognizes the energy sector as the target as it is the largest contributor to the country's total emissions.

Considering the abundance of solar power, renewable energy is prioritized in the energy sector plans. The National Energy Policy of 2021 advocates for renewable energy development through private sector participation in the electricity sector, including IPPs, to expand generation capacity.[9] According to the Renewable Energy Strategy of Botswana, the development of large-scale grid-connected renewable energy may be expected to contribute in the order of 20 per cent of total electricity consumption in Botswana by 2030, a target that would likely be met almost entirely via large-scale solar generation.[10]

The existing policies are silent on energy generation from hydropower plants considering the scarcity of the water resource in the country. Despite the potential being there, it is unlikely that any hydropower projects will be developed in Botswana in the near future.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

In 2012, Botswana developed a renewable energy feed-in tariff (FIT), which, however, was never effected due to the high estimated subsidy costs. At the moment of writing of this chapter, the FIT was undergoing review. Guidelines have been developed for rooftop solar power and biofuels, but there is no guideline in place for wind power or hydropower generation.[28]

Effective implementation of renewable energy will require public-private partnerships and this creates room for local and foreign investment. There is currently no articulated framework for public-private partnerships (PPPs) in the power sector, nor are there any standard power purchase agreements (PPAs) in place. Development of such critical policy implementation tools is vital especially given that the envisaged projects stipulated in the country's IRP have been endorsed by the Cabinet for implementation through IPPs.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Regional changes in rainfall and water availability, protracted drought events, significant variation in temperature regimes and more frequent and severe weather events are the climate change impacts that can affect the hydropower sector. These effects have an impact on the future sustainability of any SHP development, which could discourage potential investment.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key barriers to SHP development in the country include:

- No existing hydropower plants in the country;
- Lack of plans towards hydropower development;
- Flat topography;
- Limited water resources.

At the same time, networked micro-hydropower could still be a possibility despite the existing natural limitations. New studies could clarify the availability of SHP potential.

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Eswatini

Wim Jonker Klunne, Hydro4Africa

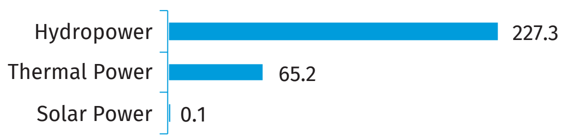
KEY FACTS

Population	1,148,130 (2019)[1]
Area	17,360 km^2[2]
Topography	The Kingdom of Eswatini is a landlocked country in Southern Africa, bordered to the north, south and west by South Africa and to the east by Mozambique. Eswatini is a small country of no more than 200 km north to south and 130 km east to west. The western half is mountainous, descending to the Lowveld region to the east. The eastern border with Mozambique and South Africa is dominated by the escarpment of the Lebombo Mountains. The lowest point is the Great Usutu River, at 21 metres above sea level, and the highest is Emlembe Mountain, at 1,862 metres.[3]
Climate	The climate is temperate in the west, but temperatures can reach 40 °C in the eastern Lowveld region during the summer months, between October and March. In the capital city, Mbabane, the average temperature is 20 °C in January and 12 °C in July.[3]
Climate Change	Despite not emitting large quantities of greenhouse gas emissions, Eswatini is facing severe climate change impacts. Variable precipitation patterns, droughts, desertification, higher temperatures and increased storm intensities have already affected the country's population and key economic sectors. As a developing, lower-middle income country, with 69 per cent of the population living below the poverty line, Eswatini has little capacity to cope with these impacts.[4]
Rainfall Pattern	Rainfall occurs mainly in the summer months, between October and March. Average annual rainfall may reach 2,000 mm in the western Highveld region, but decreases towards the east with the Lowveld region averaging between 500 mm and 900 mm.[3]
Hydrology	Major perennial rivers, which have their sources in South Africa, flow through the country to the Indian Ocean. They are the Lomati, Komati, Umbuluzi and Usutu. The Usutu has the largest catchment in the country, with three main tributaries: the Usushwana, Ngwempisi and Mkhondvo.[5]

ELECTRICITY SECTOR OVERVIEW

The Eswatini electricity grid is supplied by the Eswatini Electricity Company (EEC) through four hydropower plants (Ezulwini of 20.2 MW, Maguga of 19.5 MW, Edwaleni of 15.0 MW and Maguduza of 5.6 MW), Ubombo Sugar Limited (40.5 MW of biomass supplemented by coal), the Wundersight's Buckswood 100 kW solar photovoltaic (PV) plant and 8.2 MW of small hydropower (SHP) capacity. The country's total installed capacity as of 2020 was 109.1 MW (Figure 1). In addition, there are several private self-generating plants owned by the industrial sector. In 2021, the new 10 MW Lavumisa solar PV plant owned by the EEC began commercial operation.[6,7]

Figure 1. **Installed Electricity Capacity by Source in Eswatini in 2020 (MW)**

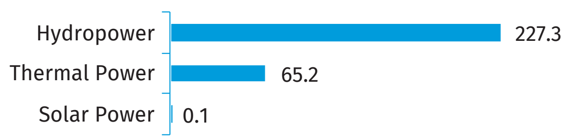


Source: EEC[6]

Note: Thermal power includes generation from coal and biomass; data do not include privately owned self-generation.

The local generation is augmented by imports through the Southern African Power Pool (SAPP), with South African utility ESKOM as the major source of electricity. The total electricity generated in the country reached 292.6 GWh at the end of the 2019/2020 financial year (Figure 2). Eswatini is still highly reliant on electricity imports, with approximately 1,028 GWh of electricity imported in 2020.[6]

Figure 2. **Annual Electricity Generation by Source in Eswatini in 2020 (GWh)**



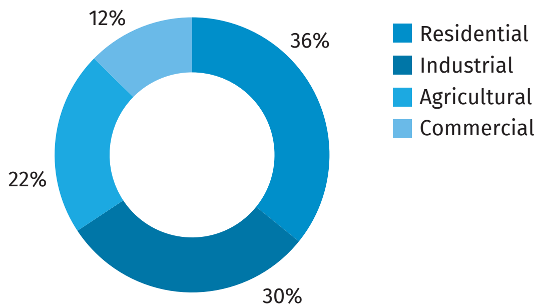
Source: EEC[6]

Note: Thermal power includes generation from coal and biomass; data do not include privately owned self-generation.

The four hydropower plants of EEC have a total installed capacity of 60.3 MW and contributed 17.2 per cent to the country's total electricity supply (including imports) in the financial year 2019/2020.[6] Total hydropower generation in 2019/2020 amounted to 227.3 GWh, compared to 266.1 GWh in the previous financial year. The EEC hydropower plants are located in the Usuthu River catchment basin (Ezulwini, Edwaleni and Maguduza plants) and in the Komati basin (Maguga plant).[6]

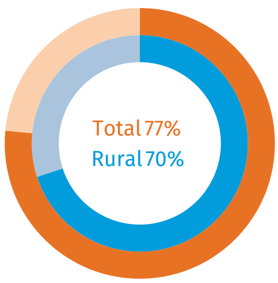
In 2020, the residential and industrial sectors dominated national electricity consumption, with 36 and 30 per cent of the total, respectively (Figure 3).[6] The overall electrification rate is estimated at approximately 77 per cent, with approximately 97 per cent of the urban areas and 70 per cent of the rural areas electrified (Figure 4).[8] Biomass, especially wood fuel, constitutes approximately 90 per cent of the total energy consumed and is still dominant in cooking and heating in rural areas. Biomass is not only the major fuel in households, but also the major source of electricity self-generation in the sugar, pulp and sawmill industries.

Figure 3. **Electricity Consumption by Sector in Eswatini in 2020 (%)**



Source: EEC[6]

Figure 4. **Electrification Rates in Eswatini in 2020 (%)**



Source: World Bank[8]

As of 1 April 2020, the consumer tariffs ranged from 1.0887 SZL/kWh (0.077 USD/kWh) to 2.4144 SZL/kWh (0.17 USD/kWh) (Table 1) for non-time of use (TOU) customers, while the price for TOU customers can be as high as approximately 5 SZL/kWh (0.35 USD).[9]

Table 1. **Consumer Tariffs in Eswatini in 2020/21**

Tariff type	*Facility charge per month (SZL (USD))*	*Energy charge per kWh (SZL (USD))*
Life line		1.089 (0.08)
Domestic		1.806 (0.13)
General purpose	208.46 (14.75)	2.414 (0.17)
Small commercial prepayment	208.46 (14.75)	2.414 (0.17)
Small commercial credit meter	416.93 (29.51)	2.414 (0.17)

Source: EEC[10]

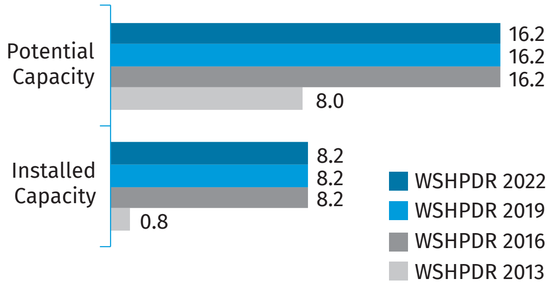
EEC was established in 2007 as the Swaziland Electricity Company (SEC) by the Swaziland Electricity Company Act of 2007.[11] It currently operates as a monopoly with regards to the import, distribution and supply of electricity via the national power grid and owns the majority of the country's power plants. There are also a number of private power plants. A substantial amount (almost 25 per cent) of the energy used in the country is supplied by self-generators. A reform of the energy sector has been undertaken to reduce the monopoly of the utility (change from a board to a company in 2007), establish a regulatory body and to ensure proper oversight over the state company as a corporate entity.[12] The following powers and functions have been given to the Eswatini Energy Regulatory Authority (ESERA; formerly the Swaziland Energy Regulatory Authority, SERA):

- Receive and process applications for the licences and modify/vary the licences;
- Approve tariffs, prices, charges, terms and conditions of operating a licence;
- Monitor the performance and efficiency of licensed operators.

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition for SHP in Eswatini, therefore, this chapter assumes a definition of plants less than 10 MW. The installed capacity of SHP in the country is currently 8.205 MW, including the decommissioned but still technically operational 0.5 MW plant at Mbabane.[13] Additional potential capacity is estimated to be at least 8 MW, indicating that more than 50 per cent of the available potential has been developed so far.[14] In comparison to data from the *World Small Hydropower Development Report (WSHPDR) 2019*, both the installed and potential capacities have remained the same (Figure 5).

Figure 5. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Eswatini (MW)**



Source: Jonker Klunne,[13] Knight Piesold Consulting,[14] WSH*PDR 2013*,[15] *WSHPDR 2016*,[16] *WSHPDR 2019*[17]

Currently, only six hydropower plants are operational in the country, three of which have capacities of less than 10 MW (Table 2).[13] EEC operates the grid connected to the Ezulwini (20.0 MW), Maguga (19.5 MW) Edwaleni (15.0 MW) and Maguduza (5.6 MW) plants. The Mbabane plant of 500 kW was decommissioned by EEC in December 2010 as it was no longer able to operate profitably.[18] In 2018, the African Development Bank submitted a concept note to the Green Climate Fund, which includes a proposed rehabilitation of the Mbabane plant at an estimated cost of USD 7 million. At the moment the AfDB Is trying to mobilize co-funding for the project before it can be considered for approval.[19] Two private SHP plants are also in operation: the 800 kW plant of Swaziland Plantations and the 1.305 MW plant of Ubumbo Sugar in Big Bend.[13]

Table 2. **List of Small Hydropower Plants in Eswatini**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Ezulwini	Ezulwini valley	20.0	–	Pelton, storage	EEC	1985
Maguga	Hhohho	19.5	50 –90	Francis, storage	EEC	2006
Edwaleni	Manzini	15.0	141	Dam with run-of-river	EEC	1969
Maguduza	Manzini	5.6	–	Dam with run-of-river	EEC	1969
Ubumbu Sugar	Big Bend	1.3	28	Cross-flow, run of river	Ubumbu Sugar	1986
Swaziland Plantations	Pigg's Peak	0.8	76	Francis, storage	Swaziland Plantations	1952
Mbabane*	Mbabane	0.5	–	–	EEC	1954

Source: Jonker Klunne[13]

Note: *decommissioned.

Both the Edwaleni and Maguduza plants feed from the Greater and the Little Usutu Rivers. In the mid to late 1980s EEC encountered serious problems with siltation in the canal and pondage system to such an extent that an island had formed. This not only reduced the plants' capacity to provide peak power but also caused severe wear on the turbines.[20] Currently, the plants are free of siltation problems. The Edwaleni plant also comprises three sets of diesel generation facilities (2 x 4.5 MW + 1 x 0.5 MW), however these are seldom utilized by EEC because of the high costs involved.

The hydropower plant of Swaziland Plantations was initially commissioned in 1952 and was built to provide for the power needs of the town of Piggs Peak. The water is taken from the river and stored in a 35-metre-high dam, before being fed into a 1.75 metre in diameter, 300-metre-long tunnel, which is then connected to the penstock. The head is 76.2 metres. The two 400 kW Francis turbines are designed to take a water flow of 0.8 m^3/s and have an efficiency of approximately 85 per cent (when running at full capacity). They are each connected to a three-phase 415 kVA alternator. The alternators feed into an 800 kVA transformer, which is synchronized to the EEC system and feeds a 16-kilometre-long, 11 kV line direct to the sawmill. During summer, when there is an abundance of water, the plant can satisfy approximately 90 per cent of the company's power needs.[21] Current operations are highly dependent on water availability, with approximately a quarter of summer production levels possible in the winter, dry season.

The 1.305 MW hydropower plant on the Great Usuthu River was commissioned in 1986 and consists of two 728 kW Ossberger turbines. The plant provides power to the sugar processing facilities in Big Bend.[13]

Feasibility studies are currently ongoing for the Ngwempisi cascading project, which is expected to have a total installed capacity of 120 MW over three different sites. Furthermore, at least one owner of an old defunct 50 kW hydropower plant just outside Mbabane is considering rehabilitation.[22] The success of the existing Maguga hydropower plant has also encouraged EEC to consider exploring the potential of adding extra generating equipment on the existing plant as well as constructing another power plant approximately 7 kilometres downstream of the current one. An engineering consulting firm has been engaged to carry out a full feasibility study, including a further investigation of the potential to develop a 10 MW site down the Maguga plant, which will utilize the existing Maguga dam. The intention is to take advantage of the remaining capacity below 35 per cent of the Maguga dam level at the downstream hydropower plant.[6] Expanding the Maguga plant will increase the local generation capacity and decrease the dependence on imported power. The extra generation units will also ensure that some of the excess water, which normally spills during the rainy seasons, is used to generate power. In addition, T-Colle Investments of Mbabane is looking to build an SZL 5 million (USD 575,000) hydropower plant with a capacity of 360 kW on a canal in the central Manzini region. The firm will charge EEC SZL 0.70 (USD 0.081) per kWh for the first three years of production (Table 3).[23]

Table 3. **List of Planned Small Hydropower Projects in Eswatini**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Development stage*
Maguga extension	Maguga	10.00	–	Feasibility study
Maguga downstream	Maguga	10.00	Run-of-river	Feasibility study
Lubovane		0.85	–	Feasibility study
Dwaleni's Ferreira Canal	Manzini	0.36	Run-of-river	Feasibility study
Mbabane	Mbabane	0.05	–	Feasibility study

Source: Jonker Klunne[13]

A joint 1987 United Nations Development Programme (UNDP) and Energy Sector Management Assistance Programme (ESMAP) study on the energy sector in Eswatini identified a total of approximately 1 MW of non-utility hydropower generation capacity.[21] The latest full study on hydropower potential in Eswatini however was carried out by Knight Piesold Consulting in 2001. The study showed that there is a number of potential micro- (<0.1 MW), mini- (0.1–2.0 MW) and small (2–10 MW) hydropower sites with an available potential of approximately 8 MW.[24] As part of its objective to expand the hydropower sector, the Ministry of Natural Resources and Energy (MNRE) has, based on the findings of Knight Piesold Consulting, built a database of potential sites. Initially, 35 candidate sites were identified, ranging from 32 kW to 1.5 MW. This was further reduced to 26, based on the potential for electricity generation. Four have been identified as viable projects and are being promoted by MNRE: Lusushwana River (300 kW), Mpuluzi River (155 kW), Usutu River (490 kW) and Mbuluzi River (120 kW minimum) (Table 4).[25]

Several studies have been undertaken to estimate the total hydropower potential of Eswatini. In 1970, the UNDP financed a study by Engineering and Power Development Consultants, which identified 21 potential sites.[20] Based on existing information, the Environmental Centre for Swaziland (now Eswatini Environment Authority) estimated a gross theoretical potential of 440 MW and technically exploitable potential of 110 MW, of which 61 MW is economically exploitable.[25]

Table 4. **List of Small Hydropower Sites Available for DDevelopment in Eswatini as of 2021**

Name	*Potential capacity (MW)*	*Type of site (new/ refurbishment)*
Lusushwana River	0.300	New
Mpuluzi River	0.155	New
Usutu River	0.490	New
Mbuluzi River	0.120	New

Source: IRENA[26]

RENEWABLE ENERGY POLICY

In 2007, MNRE formulated a strategic framework and action plan with the aim to:

- Establish a centre for demonstration and education on renewable and sustainable energy;
- Encourage and enhance, where applicable, topics on renewable energy and energy in general in educational and training curricula;
- Maximize the use of renewable energy technologies wherever they are viable;
- Promote greater understanding and awareness of renewable energy resources and associated technologies;
- Develop and maintain accurate data on renewable energy resources and make them available to all, in order to make informed policy decisions regarding the sustainable energy use and supply;
- Develop woodlots in areas where there is an acute fuel wood shortage.[27]

A more recent Master Energy Plan 2034 was developed in 2018 with the aid of the International Renewable Energy Agency (IRENA).[28] The plan asserts that under a limited import scenario, 676 MW of domestic capacity must be secured if projected demand is to be met in 2034 while assuring adequate reserves. Under the policy's limited import 2 scenario, hydropower is to make up 120 MW of installed capacity by 2025.

There are no specific regulations pertaining to SHP in the country, nor is there available information on cost and specific financial mechanisms. Financial incentives for other off-grid renewable solutions are only available in the form of development finance, as demonstrated by projects funded from UNDP and the World Bank.[29]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The climate crisis is likely to affect the river flow rate in the country. This foreseen fluctuation will affect hydropower capacity factors and make predictions more difficult.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The hydropower resources of Eswatini have been well documented and with the 2007 electricity sector reforms a legal framework for the introduction of independent power producers has been created. However up until now multiple barriers have made the development of SHP in the country difficult. Some of the most noteworthy barriers include:

- Limited private sector investment;
- Reduced reliability of the national grid;
- Lack of a good overview of potential sites for refurbishment.

The enabling factors include:

- Renewed interest in hydropower as an energy source, as indicated through the recent studies on the Ngwempisi cascading project and the Lower Maguduza plant, suggesting that new developments may progress more positively in the future;
- Increasing electricity prices and the reduced reliability of the national grid have resulted in increased interest in rehabilitation of the old defunct hydropower plants; it can be expected that a number of sites will be economically feasible to rehabilitate.

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Lesotho

Wim Jonker Klunne, Hydro4Africa

KEY FACTS

Population	2,125,268 (2019)[1]
Area	30,360 km^2 [2]
Topography	Lesotho is a small country surrounded by the Republic of South Africa. The lowest elevation in the country is at the junction of the Makhaleng and Orange (Senqu) Rivers (at the border with South Africa), which at 1,400 metres is the highest lowest point of any country in the world. Lesotho is the only country that lies entirely above 1,000 metres in elevation. The highest point is the peak of the Thabana Ntlenyana mountain, which reaches an elevation of 3,482 metres. Approximately one quarter of the land area is represented by lowlands located in the west and varying in height from 1,500 to 1,600 metres above sea level. The remaining three quarters are highlands running from north to south, while the central ranges, the Maluti, are spurs of the main Drakensberg, which they join in the north, forming a high plateau lying at 2,700–3,400 metres.[3,4]
Climate	The climate in the country is temperate with cool to cold winters and hot, wet summers. The maximum temperature can exceed 30 °C in the lowlands in January, whereas in the mountains the temperature can fall to -20 °C in the winter.[5]
Climate Change	Lesotho is expected to experience a change in temperature and precipitation patterns, towards drier and hotter conditions. In addition, the intensity and frequency of extreme events such as floods and droughts are expected to increase, especially in the western and northern lowlands. Water resources will be affected negatively by the reduction of precipitation and increase in temperature. This will result in an increase in evaporation losses and a decrease in runoff and groundwater recharge.[6]
Rain Pattern	Rainfall is seasonally distributed, with up to 85 per cent of the total received from October through April. Average annual precipitation is 788 mm, varying from 300 mm in the western lowlands to 1,600 mm in the north-eastern highlands.[5]
Hydrology	Two of the largest rivers in Southern Africa, the Orange (Senqu) River and the Tugela River, as well as tributaries of the Caledon River have their source in the northern region of Lesotho. The country is entirely located within the Orange River basin, with the Orange draining two thirds of the country and its tributaries the Makhaleng and the Caledon covering the rest. The Lesotho Highlands Water Project (LHWP) is an ongoing water supply project with a hydropower component, developed in partnership between the Governments of Lesotho and South Africa. It comprises a system of several large dams and tunnels throughout Lesotho and delivers water to the Vaal River System in South Africa. In Lesotho, it involves the Malibamatso, Matsoku, Senqunyane and Senqu Rivers.[4,5]

ELECTRICITY SECTOR OVERVIEW

Lesotho does not have any proven domestic reserves of oil, coal or natural gas and heavily depends on biomass fuels in the forms of wood, shrubs, animal dung and agricultural residues to meet the energy needs of the majority of the population. The other fuels consumed in significant quantities are mineral coal, liquefied petroleum gas (LPG) and paraffin.[7]

The electricity sector is relatively small with an installed capacity of 77 MW as of 2020 (Figure 1).[8,9] This mainly came from the 72 MW 'Muela hydropower plant linked to and managed by the Lesotho Highlands Water Development Authority (LHWDA) scheme to provide water to South Africa. Peak demand has been seen to reach 167 MW, forcing the Government to meet the deficit through imports from Mozambique and South Africa. In 2019/2020, the Lesotho Electricity Company (LEC) purchased 389.1 GWh from the 'Muela hydropower plant and imported 429.8 GWh from South Africa and 99.5 GWh from Mozambique.[10] When electricity demand is low, Lesotho exports excess electricity produced by 'Muela hydropower plant to ESKOM, due to the country's lack of electricity storage capacity.[7]

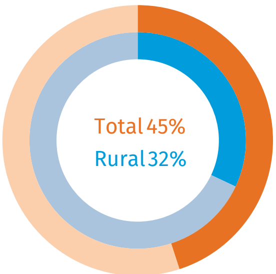
Figure 1. **Installed Electricity Capacity by Source in Lesotho in 2020 (MW)**

Source: Department of Energy,[9] Bureau of Statistics[10]

Hydropower generation in Lesotho has typically been a strong source of generation, but has experienced shortfalls in recent years. In 2018, generation from the 'Muela hydropower plant reached 515.8 GWh, but by 2019 this dropped to 391.7 GWh.[10] Small hydropower (SHP) plants, such as Semonkong, experience the highest generation in summer months. Most of the Semonkong generation in recent years has come from diesel generation, with only 0.06 GWh in 2018/2019 coming from hydropower, representing just 9 per cent of the plant's total electricity generation that year (0.7 GWh).[11] The Mantšonyane SHP plant generation in 2019/2020 was only recorded for January at 0.03 GWh.[10]

Nationwide, approximately 45 per cent of the population had access to electricity in 2019, a revision downwards of 5 per cent from 2018 estimates. Electricity access rates are 76 per cent for urban areas and 32 per cent for rural areas.[12]

Figure 2. **Electrification Rate in Lesotho in 2019 (%)**



Source: World Bank[12]

Besides hydropower, Lesotho possesses significant resources of other renewable energy sources. In preparation of the recent Scaling up Renewable Energy Programme (SREP) Investment Plan for Lesotho, the Government carried out a renewable energy resource assessment (Table 1).[9]

Table 1. **Technical Potential of Low Carbon Technologies in Lesotho under SREP**

Technology	Technical potential (MW)
Utility-scale wind power	2,077
Utility-scale solar PV	118
Micro-solar power technologies	38
Small-scale hydropower	36
Solar power micro-grids	31
Waste to energy	10
Solar power home systems	1
Floating micro-hydropower	0.5
Total	**2,311.7**

Source: Department of Energy[9]

The electricity supply industry in Lesotho is regulated by the Lesotho Electricity and Water Authority (LEWA). LEWA is an independent regulator responsible for issuing licences, approving electricity tariffs, setting and monitoring the quality of supply and service standards and resolving disputes between suppliers and customers. LEWA has the authority to regulate all aspects of the industry, including the generation, transmission, distribution, supply, import and export of electricity.[13]

Electricity is supplied by the Lesotho Electricity Company (LEC). LEC is a parastatal entity established under the Electricity Act 7 of 1969 and is empowered to distribute, transmit and supply electricity. In 2000, the Lesotho Utilities Sector Reform (LURP) unsuccessfully attempted to privatize LEC and to date the utility remains state-owned. The Lesotho Highlands Water Development Authority (LHWDA) is the agency responsible for the electricity generation from the 'Muela hydropower plant. The roles and responsibilities of these two bodies are set out in the 1993 Policy on the LHWDA/LEC interface.[9]

Electricity tariffs in Lesotho vary by consumption category and in 2020/2021 were as shown in Table 2.

Table 2. **Electricity Tariffs in Lesotho in 2022/2021**

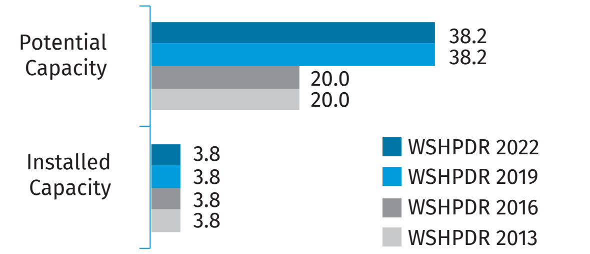
Customer category	*Final electricity price (LSL (USD) per kWh)*	*Increase vs. 2017/2018 rates (%)*
Industrial high-voltage	0.2559 (0.017)	3.0
Industrial low-voltage	0.2767 (0.018)	3.1
Commercial high-voltage	0.2559 (0.017)	3.0
Commercial low-voltage	0.2767 (0.018)	3.1
General purpose	1.6608 (0.110)	3.8
Domestic	1.4782 (0.097)	3.8
Lifeline domestic	0.7273 (0.048)	–
Street lighting	0.8725 (0.057)	3.7

Source: LEWA[14]

SMALL HYDROPOWER SECTOR OVERVIEW

SHP is defined in Lesotho as hydropower plants with capacity of up to 10 MW.[9] As of 2021, the installed capacity of SHP plants was 3.82 MW, of which 2.2 MW was operational, while the potential was estimated at approximately 38.2 MW.[15] Neither installed nor potential capacity estimates have changed since the publication of the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Lesotho (MW)**



Source: Jonker Klunne,[15] *WSHPDR 2013*,[16] *WSHPDR 2016*,[17] *WSHPDR 2019*[18]

There are five SHP plants in Lesotho: Mantsonyane (2 MW), Tlokoeng (670 kW), Katse (540 kW), Tsoelike (400 kW) and Semonkong (180 kW) (Table 1). However, out of these five, only the Mantsonyane and Semonkong plants are currently operational.[15] As of 2021, the Katse plant (on the Katse dam) is decommissioned due to earlier flooding. The Government of Lesotho engaged with the Japan International Cooperation Agency (JICA) to have it rehabilitated and connected to the national grid. The commencement of the work is expected sometime in 2022.[19]

Table 3. **List of Installed Small Hydropower Plants in Lesotho**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Katse (non-operational)	Katse Dam	0.54	–	Reservoir	LHDA	2000
Tsoelike (non-operational)	Qacha's Nek	0.40	–	Run-of-river	LEC	1990
Tlokoeng (non-operational)	Mokhotlong	0.67	–	Reservoir	LEC	1990
Semonkong	Semonkong	0.19	18.0	Run-of-river	LEC	1989
Mantsonyane	Mantsonyane	2.00	35.5	Reservoir	LEC	1989

Source: Jonker Klunne[15]

The Tsoelike hydropower plant is a 400 kW run-of-river installation that was constructed to serve the town of Qacha's Nek in the south of Lesotho, close to the border with South Africa. It was commissioned on 5 February 1990 as part of French development assistance to Lesotho. The plant consists of two Francis hydropower turbine generation units, supplemented by a 200 kVA diesel generator set located on a ledge next to the power plant and a 320 kVA set at the town of Qacha's Nek. Qacha's Nek previously had an isolated electricity system, but has been connected to the South African ESKOM grid since 1997. This cross-border connection has enabled LEC to decommission the plant in 2000 as it was developing serious technical and siltation problems due to the design of the plant allowing silt to enter the system.

Tlokoeng is a 670 kW plant in the eastern part of the country, built with French development aid to serve the town of Mokhotlong. The plant has two Francis turbines of 460 kW and 210 kW capacity, augmented by two diesel generator sets as backup — one diesel set at the plant itself (200 kVA) and another of 500 kVA at Mokhotlong town. The plant was commissioned in February 1990 and over its operational life provided on average 27 per cent of the electricity demand of Mokhotlong, ranging from a low of 2 per cent in 1999 to a maximum of 47 per cent in 2000.[20] Originally designed for cyclic storage, equivalent for 27 hours output at full load, due to the siltation of the storage reservoir it effectively turned into a run-of-river plant. The plant is located on the Khubelu River and has seen a history of technical problems related to the bearing failures and exciter problems as well as flooding in 1996. It was decommissioned in November 2002 when the 33 kV transmission line from the Letseng diamond mine reached the town of Mokhotlong. Since then, plans have been tabled to use the plant for peak lopping and/or operation as an independent power producer (IPP), but no concrete steps have been taken to this effect. The difficult access situation and limited availability of spare parts for the original French equipment have inhibited the development of the site.

The Mantsony'ane hydropower plant was financed by a grant from Norway and handed over to LEC on 6 February 1989. It is located on the Mantsony'ane River in central Lesotho and is feeding the LEC grid through the Mantsony'ane substation on the 33 kV line Mazenod–Taba Tseka. The plant can operate on an isolated network if required, but the main operational strategy has been daily peak lopping. The plant is equipped with two Francis turbines of 1,500 kW and 500 kW, coupled with a 1,900 kVA and a 650 kVA generator, respectively. It features a storage reservoir on the river and an unlined 655-metre-long tunnel from the intake to the rock cavern power house. The design head is 35.5 metres. The power plant was flooded with water in November 2006 and was out of operation for a couple of years. It was later rehabilitated as part of the African Development Bank's Lesotho Electricity Supply Project.[21,22]

The Katse Dam, a concrete arch dam on the Malibamat'so River, is the second largest dam in Africa and is part of the Lesotho Highlands Water Project, which is planned to include five large dams in remote rural areas. Although the main purpose of the Katse Dam is water storage and diversion, a mini-hydropower plant is included. The plant is located 123 metres below the spillway level of the Katse Dam and consists of a horizontal Francis turbine and an 800 kVA synchronous generator. Since its commissioning in August 2000, the plant has been run in isolation from the LEC grid as the main power source for the Katse Dam electricity requirements. At the moment, the plant is not in use due to flooding damage and awaiting rehabilitation, which is expected to start in 2022.

The Semonkong hydropower project was designed for 180 kW of hydropower capacity supplemented by a 120 kW diesel generator. Currently, due to wear and tear on the Sorumsand Verksted turbine, the hydropower equipment is able to produce 125 kW only. The diesel generator has been upgraded twice since its installation and is currently a 180 kW Cummins unit. The Semonkong hydropower project, developed as part of a Norwegian development aid project, was commissioned in 1988 and officially opened in 1990. The plant powers an isolated mini-grid that serves the town of Semonkong and has 161 customers, consisting of 113 households and 48 commercial connections, all on prepaid meters. The Semonkong powerhouse was designed with provision for a second hydropower turbine. However, it will only be feasible to install this second turbine if a larger reservoir is constructed for increased water supply. The hydropower project comprises an intake structure, a headrace and penstock piping, a powerhouse and power generating equipment. The intake structure consists of a 100-metre-long concrete weir, a headrace inlet with a trash rack and a simple pipe with a light steel gate for the flushing of sediment in front of the intake. The low-pressure headrace is a 290-metre-long concrete pipe and the penstock is a 150-metre-long glass fibre-polyester pipe. A standard design, cast-in-place concrete surge chamber is located at the upstream end of the penstock.[23] Under the recently approved World Bank Lesotho Renewable Energy and Energy Access project, the Semonkong plant will be rehabilitated and hybridized with a 1.5 MW solar photovoltaic (PV) plant and storage of 500 kWh. This will allow the customer base to be expanded with an additional 100 customers.[24]

There is a substantial potential for further SHP development in Lesotho. Technical assessments for SHP potential were conducted as part of the Power Generation Master Plan in 2009, which proposed hydropower sites with a combined capacity of nearly 88 MW. These include eight SHP sites with a combined capacity of 36.33 MW. The technical potential of each proposed site was re-evaluated as part of the SREP Investment Plan for Lesotho. The analysis also covered the existing non-operational plants. The exclusion criteria for the technical analysis included urban areas, proximity to wetlands, protected areas, freshwater ecological protected areas and areas within 20 kilometres of the nearest transmission line. Four of the original 11 sites proposed in the Master Plan and the existing but non-operational SHP plant Tsoelike met the eligibility criteria. In addition, the analysis revealed one previously unidentified site (Table 4).[9]

As part of the preparatory work for phase 2 of the Lesotho Highlands Water Project (LHWP), feasibility studies were carried out on the inclusion of pumped storage, such as the Kobong plant. However, the decision was made to defer the pump storage option (due to prevailing economic conditions) and advance the conventional options. This entails one site at Oxbow on the Malibamatšo River and two sites on the Senqu River, all three in the large hydropower category.[25]

Table 4. **List of Small Hydropower Projects Available for Investment**

Name	Location	Potential capacity (MW)	Type of site (new/refurbishment)	Type of plant
Makhaleng 4	Makhaleng	9.1	New	Reservoir
Makhaleng 3	Makhaleng	8.9	New	Run-of-river
Hlotse	Hlotse	6.5	New	Reservoir
Phuthiatsana	Phuthiatsana	5.4	New	Reservoir
Thaba-Tseka	Mali-bamat'so	4.5	New	Reservoir

Source: Department of Energy[9]

RENEWABLE ENERGY POLICY

The Lesotho Energy Policy 2015–2025 noted that renewable energy sources and energy efficiency are expected to play a significant role in the country's future energy plans and explicitly stated the Government's aim of improving access to renewable energy services and technologies. Strategies and programmes include facilitating the establishment of rural energy service companies (RESCOs) and developing a renewable energy programme to support fossil fuel substitution.[9]

In 2015, LEWA, with the support of the African Development Bank, prepared a draft Regulatory Framework for the Development of Renewable Energy Resources, which in particular covers feed-in tariffs, procurement guidelines and templates for various licences, tenders and power purchase agreements (PPAs). Many components of this framework have been incorporated in the Energy Act. Moreover, it is expected that the project of the United Nations Development Programme (UNDP) and the Global Environment Facility (GEF) Development of Cornerstone Public Policies and Institutional Capacities to accelerate Sustainable Energy for All (SE4All) Progress, which is currently ongoing, will assist in creating a more conducive environment for renewable energy.[26,27]

COST OF SMALL HYDROPOWER DEVELOPMENT

Costs of SHP remain high in the country, as elsewhere, since costs of SHP are higher per MW of installed capacity than larger hydropower plants.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Much of the financing for projects in the country are reliant on international development aid or project financing.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Poor rainfall in recent years has significantly impacted the hydropower sector, leading the few remaining operational SHP plants such as the Semonkong and the Mantšonyane to significantly decrease generation output. This makes for a poor SHP business case, and puts the future of the sector in jeopardy.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In general, the conditions in Lesotho can be described as conducive in terms of the legislation framework allowing the operation of independent power producers and distributors.[28] However, it has proven to be difficult for international partners to find viable business models for the development of SHP in Lesotho. For example, Tarini Hydro Power Lesotho Ltd., a subsidiary of Tarini in India, has been trying for a couple of years now to start two hydropower projects (the 80 MW Oxbow and 15 MW Quithing projects) but still has not been able to commence construction works.[29]

However, with the renewed interest in renewable energy, and in particular mini-grids, promising signs are emerging. One of the solar mini-grid developers in the country is about to launch a GIS-based exercise to determine whether some of its solar mini-grids can be hybridized with SHP.

The key barriers to the development of SHP in Lesotho include:

- Poor water resources, leading to poor capacity factors for existing plants;
- Lack of effective infrastructure;
- Fragmented institutional responsibilities;
- Lack of integrated planning;
- A rather small size of the potential market and the limited ability to pay on the part of the rural population;
- Limited skills required for SHP construction, operation and maintenance;
- Low general awareness of SHP as well as of other renewable energy technologies;
- Difficulties in accessing some sites;
- Limited availability of spare parts in the local market;
- Low water levels mean that SHP is no longer viable and existing plants might not generate due electricity.

No clear enabling factors have been identified for the development of SHP in the country.

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Namibia

Davy Rutajoga, International Center on Small Hydro Power (ICSHP)

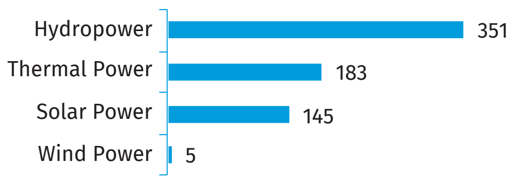
KEY FACTS

Population	2,540,916 (2020)[1]
Area	824,290 km^2 [2]
Topography	Namibia is characterized by four topographical regions: the Namib desert, the Central Plateau running from north to south with an altitude reaching up to 2,000 metres above sea level, the eastern lowlands that include the Kalahari Desert and, to the north-east, the high rainfall areas of Caprivi and Okavango. The highest mountain in the country is the Brandberg peaking at approximately 2,579 metres above sea level, followed by the Moltkeblick with a height of 2,480 metres.[3]
Climate	Namibia is one of the driest and most arid countries in Sub-Saharan Africa. Characterized by high climatic variabilities with constant droughts, variable temperatures, water scarcity and unpredictable rainfall patterns. With 92 per cent of the land area considered very arid, arid or semi-arid, Namibia is second only to the Sahara Desert in aridity on the continent. The annual temperatures in the country average between 14 °C and 24 °C, with the north averaging 22 °C and the southern coast below 16 °C. Apart from the coastal area, the highest temperatures occur in the wet season in drier areas and right before the wet season in wetter areas. The dry season, when the lowest temperatures occur, lasts from June to August.[4]
Climate Change	Namibia has been experiencing the effects of climate change through increased unpredictability and variability in rainfall patterns, frequent droughts and increased annual temperatures. This has been affecting agriculture, with droughts reducing agricultural productivity and thus leading to reduced income for farmers and death of livestock. The annual mean temperatures have been observed to be increasing since the 1960s, particularly at night-time. The frequency of days with maximum temperatures exceeding 25 °C and 35 °C has been increasing and the frequency of days with temperatures below 5 °C has been decreasing. An increase in overall rainfall scarcity as well as an increase in heavy rainfall events have been observed, with noted changes in onset, duration and intensity of rainfall.[4,5]
Rain Pattern	Due to the arid nature that characterizes Namibia, rainfall is scarce and highly variable and potential evaporation is approximately five times greater than average rainfall. The annual mean rainfall is 279 mm, varying from 650 mm in the north-east to less than 50 mm in the south-west. Rainfall in the Namib Desert area is extremely scarce. Mean monthly rainfall averages 62 mm, 66 mm and 55 mm in January, February and March, respectively. The rainy season in Namibia is from October to April, with minimal rainfall in May and September.[4]
Hydrology	Of the scarce rainfall received in Namibia, 83 per cent is evaporated, 14 per cent is lost through transpiration, 2 per cent is run off into rivers and 1 per cent seeps underground. Within one season, the country can lose 20–85 per cent of its water through evaporation. Namibia has five perennial rivers: the Orange, the Kunene, the Kavango, the Zambezi and the Kwando (also known as Linyanti and Chobe).[6]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in Namibia are hydropower, solar power, thermal power and wind power. In 2019, these sources accounted for 71 per cent, 19 per cent, 9 per cent and 1 per cent, respectively, of total electricity production, which amounted to 1,818 GWh (Figure 1). As a country that relies heavily on imported electricity, Namibia imports over 60 per cent of the total electricity consumed from neighbouring countries through bilateral contracts with Eskom of South Africa, Zimbabwe and the Southern Africa Power Pool (SAPP).[7]

Figure 1. **Annual Electricity Generation by Source in Namibia in 2019 (GWh)**

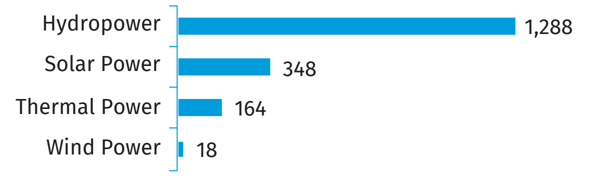


Source: IRENA[7]

In 2017, Namibia decided to update its Energy Policy of 1998 with a more future-oriented one — the National Energy Policy of 2017 (NEP). This new policy aims to usher in a more sustainability-focused approach to the energy sector, while acknowledging the country's reliance on neighbouring countries to meet most of its needs in electricity and the importance of developing and exploiting its own natural energy resources.[8] The NEP is aligned with the country's Vision 2030, an integrated long-term national development strategy that aims to improve the quality of life in Namibia to the level of developed countries by 2030.[10] In order to achieve this, the Government has been making efforts to attract foreign investment to develop the country's own hydrocarbon potential by establishing the country as an attractive destination for both international oil companies and local actors.

Much of the locally generated electricity in Namibia is produced by the Government-owned power utility NamPower, which operates the generation facilities: Ruacana hydropower plant, the Van Eck coal power plant, the Paratus diesel power plant and the Anixas diesel power plant.[9] As of 2020, Namibia had a total installed electricity capacity of approximately 684 MW, of which hydropower, thermal power, solar power and wind power represented 51 per cent, 27 per cent, 21 per cent and 1 per cent, respectively (Figure 2).[7]

Figure 2. **Installed Electricity Capacity by Source in Namibia in 2020 (MW)**



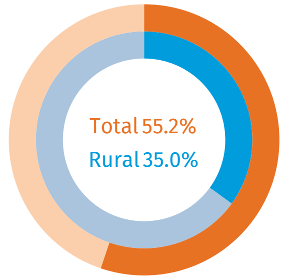
Source: IRENA[7]

NamPower, born out of the South West Africa Water and Electricity Corporation (SWAWEK) in 1996, controls the generation, transmission and supply of energy to the various Regional Electricity Distributors, mines and farms throughout the country. In an effort to be less reliant on imports from South Africa, NamPower has signed power purchase agreements with utilities in neighbouring Zambia, Botswana, Zimbabwe, Zambia, Mozambique and the Democratic Republic of the Congo (DRC). The company has also completed the TransCaprivi Interconnector which directly connects NamPower to the power grids of Zimbabwe and Zambia. NamPower is overseen by the Ministry of Mines and Energy (MME) and regulated by the Electricity Control Board.[11,12]

Since 2019, independent power producers (IPPs) can sell electricity to large power users both locally and internationally, across the national transmission grid. This marks a trend towards the decentralization of electricity production, transmission and supply in Namibia.[12]

The total electrification rate in Namibia was 55 per cent in 2019, with an urban access rate of 75 per cent and a rural access rate of 35 per cent (Figure 3).[13]

Figure 3. **The Electrification Rate in Namibia in 2019 (%)**



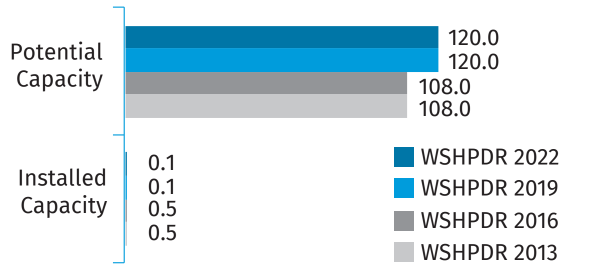
Source: AEP[13]

Electricity tariffs in Namibia are regulated by the Electricity Control Board (ECB), established by the Electricity Act 2 of 2000 and expanded by the Electricity Act 4 of 2007. The ECB's statutory functions are executed through the Technical Secretariat and include the reviewing, setting and approving of all tariffs in the country.[14] The cost of electricity for the end consumer depends on the location, electricity distribution company and specific tariff. In 2021–2022, NamPower distribution tariffs ranged between 1.29 NAD/kWh and 2.29 NAD/kWh (0.089–0.160 USD/kWh), with additional levies and charges applied.[15]

SMALL HYDROPOPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in Namibia, therefore, for the purposes of this chapter, a definition of up to 10 MW will be used. There is currently one operational SHP plant in Namibia, with a capacity of 50 kW. Plans have been devised to develop 13 more SHP plants in the country by exploiting the resources of the Orange River, which could have an estimated capacity of 120 MW and generate approximately 380 GWh/year. The installed and potential capacities have not deviated since the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 4).[16,17]

´Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Namibia (MW)**



Source: MME,[16] MEFT,[17] *WSHPDR 2013*,[18] *WSHPDR 2016*,[19] *WSHPDR 2019*[20]

The only operational SHP plant in Namibia is located between the village of Divundu and the Angola border, some 20 kilometres upstream the Popa Falls. There are a number of factors affecting the development of SHP including increasing drought periods, scarce rainfall and the location of potential sites at borders with neighbouring countries.[16]

RENEWABLE ENERGY POLICY

Namibia is one of the countries that experiences the highest solar irradiation regime, endowing it with tremendous potential for the development of solar power. The country also has considerable potential for the development of wind power due to strong winds in its coastal areas. There are also numerous hot springs in Namibia that could be harnessed for thermal power and rivers for hydropower development. In order to more efficiently exploit these natural resources for the development of the country, cohesive policies that would tie into the country's Vision 2030 were needed. The Government of Namibia formulated the Renewable Energy Policy (REP) of 2017 to boost the renewable energy sector and signal to local and potential international actors that the country is committed to invest in its natural resources.[21]

In order to implement the REP, further instruments such as the IPP framework and the Energy Efficiency Policy were introduced. The long-term National Integrated Resource Plan (NIRP), adopted in 2016, guides IPPs, power sector planners and electricity customers in Namibia. The REP also synthesizes elements of previously introduced policies such as the Fourth National Development Plan (NDP-4) 2012/2013–2016/17, the Off-Grid Energization Master Plan (OGEMP) of 2007, the National Policy on Climate Change of 2011 and the country's Intended Nationally Determined Contribution to the United Nations Framework Convention on Climate Change (UNFCCC).[21]

Namibia aims to achieve universal electricity access and a 70 per cent share of renewable energy in its generation mix by 2030, with all of it being locally produced. In order to stimulate and facilitate local and international investment in renewable energy in the country, the Government of Namibia introduced net-metering rules for installations that total up to 500 kW for all renewable energy technologies. Feed-in tariffs (FITs) on renewable energy were also introduced for projects that are between 500 kW and 5 MW in capacity, including solar power, biomass and wind.[21]

In addition to these policies, the Government of Namibia introduced the Solar Revolving Fund (SRF) in 1996 through the MME as part of the OGEMP. This fund offers subsidised loans to the citizens of Namibia at a fixed interest rate of 5 per cent per annum for five years. Through the SRF, photovoltaic pumps, solar home systems, solar water heaters and energy-efficient stoves are financed.[22]

Though there is no targeted support for hydropower, a number of funding opportunities by African institutions are being considered by the Government of Namibia to support renewable energy projects in general, including hydropower, such as the African Development Bank's Clean Energy Investment Framework for Africa, the Sustainable Energy Fund for Africa and the African Renewable Energy Fund.[21]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

In Namibia, SHP plants are regulated by the same legislation as larger hydropower projects. The main regulation and legislation documents regarding hydropower in Namibia are:

- The Electricity Act (2007);
- The Water Resources Management Act (2013);
- The S.W.A Water and Electricity Corporation Act (1980).

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In Namibia, SHP development has been hindered by:

- High upfront capital costs exacerbated by high credit costs;
- Exchange rate fluctuations affect funding as the Namibian Dollar (NAD) is pegged by the South African Rand, which is subject to fluctuations affecting Namibia. As tariffs are set in NAD and foreign investment is in foreign currency, the devaluation of the NAD renders many projects costly;
- Insufficient government funding;
- Scarce inland water resources, as most of the important water resources are shared with neighbouring countries;
- Climate change is expected to exacerbate natural climate variability, creating more unpredictability of the hydrological regime;
- The legislation and policy in relation to SHP are unclear and need to be developed;
- Indigenous populations have concerns over displacement and other effects hydropower plant construction can have on their way of life.[5,21,23]

On the other hand, SHP development in Namibia is encouraged by:

- Government's interest in the exploitation of natural resources (solar, wind, thermal power) demonstrates an openness to maximizing the use of domestic resources, which could eventually include SHP;
- Government's interest in the development of renewable energy;
- National strategy aimed at making Namibia a hub for international investors in the energy sector;
- Trend towards the decentralization of the electricity sector that attracts local and international actors who can produce, transmit and supply electricity;
- Positive policy on renewable energy including renewable energy funds and FITs.

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South Africa

Wim Jonker Klunne, Hydro4Africa; and Bohuslav Barta, Energy and Water Resources Engineering Consultant

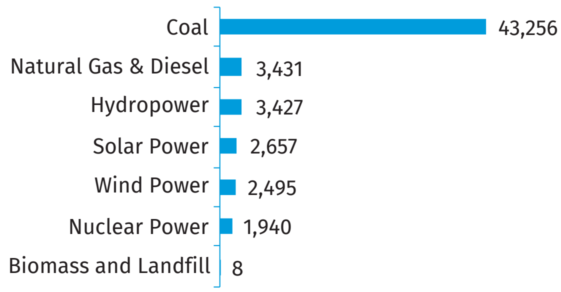
KEY FACTS

Population	59,620,000 (2020)[1]
Area	1,219,602 km^2 [2]
Topography	The territory of the country consists of a vast interior plateau rimmed by rugged hills and a narrow coastal plain. The elevation varies from approximately 1,500 metres above sea level in the dolerite-capped Roggeveld scarp in the south-west to 3,482 metres in the KwaZulu-Natal Drakensberg.[2]
Climate	South Africa is located in a subtropical region, though the Atlantic and Indian Oceans surrounding the country on three sides moderate its climate to warm temperate conditions. On the interior plateau, the high altitude (Johannesburg lies at 1,694 metres above sea level) keeps the average summer temperatures below 30 °C. In winter, night temperatures can drop to the freezing point.[2]
Climate Change	South Africa is already experiencing significant impacts of climate change, particularly as a result of increased temperatures and rainfall variability. Since 1990, the rate of increase of the national average temperature has been more than double that of global temperature increases in the same period. This increase is more pronounced for the western parts and the north-east of the country. There is evidence that extreme weather events in South Africa are increasing, with heat wave conditions found to be more frequent, dry spell durations lengthening slightly and rainfall intensity increasing.[3]
Rain Pattern	Average annual rainfall is 464 mm. Regional rainfall varies widely, from less than 50 mm in the Richtersveld (on the border with Namibia) to more than 3,000 mm in the mountains of the Western Cape. However, only 28 per cent of the country's territory receives more than 600 mm of rainfall. The Western Cape receives most of its rainfall in winter, while the rest of the country generally sees wetter summers.[2]
Hydrology	The country's largest river is the Orange River, which rises in the Drakensberg Mountains, traverses the Lesotho Highlands and joins the Caledon River between the Eastern Cape and the Free State. Other major rivers are the Vaal, Breede, Komati, Lepelle (previously Olifants), Tugela, Umzimvubu, Limpopo and Molopo.[2]

ELECTRICITY SECTOR OVERVIEW

Electricity production in South Africa is dominated by coal. During the 2020/2021 fiscal year, a total of 214,926 GWh of electricity was generated. Of this total, 13,526 GWh (6 per cent) was generated by independent power producers (IPPs) and the rest by plants operated by the public utility ESKOM, including coal-fired power plants producing 183,553 GWh (85 per cent), nuclear power producing 9,903 GWh (5 per cent), large hydropower producing 6,182 GWh (3 per cent), open-cycle gas turbines producing 1,457 GWh (1 per cent) and wind power producing 305 GWh (less than 1 per cent) (Figure 1). Electricity imports in 2020/2021 stood at 8,812 GWh.[4]

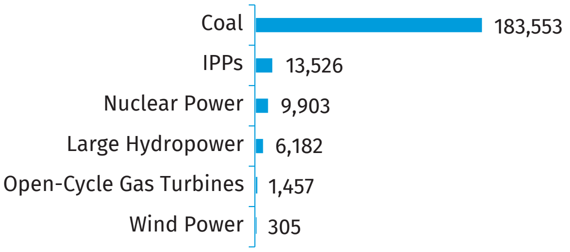
Figure 1. **Annual Electricity Generation by Source in South Africa in 2020/2021 (GWh)**



Source: ESKOM[4]

In 2021, the total installed capacity of South Africa was 57,214 MW, of which 43,256 MW (76 per cent) was represented by coal power plants, 3,431 MW (6 per cent) by natural gas and diesel power plants, 3,427 MW (6 per cent) by hydropower plants, 2,657 MW (5 per cent) by solar power plants, 2,495 MW (4 per cent) by wind power plants, 1,940 MW (3 per cent) by nuclear power plants and 8 MW (less than 0.1 per cent) by other sources including biomass and landfills (Figure 2). Approximately 89 per cent of total installed capacity was owned by ESKOM and the remaining 11 per cent was owned by Independent Power Producers (IPPs) and municipalities.[4]

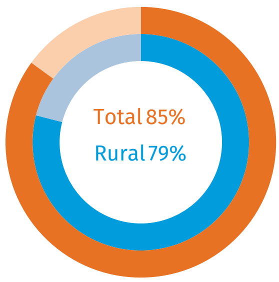
Figure 2. **Installed Electricity Capacity by Source in South Africa in 2021 (MW)**



Source: ESKOM[4]

Access to electricity across South Africa reached 85 per cent in 2019 (Figure 3). However, access to electricity in rural areas was only 79 per cent the same year and has been experiencing a decline since reaching nearly 84 per cent in 2014.[5]

Figure 3. **Electrification Rate in South Africa in 2019 (%)**



Source: World Bank[5]

The institutional framework of the electricity sector in South Africa includes the Department of Mineral Resources and Energy (DMRE) (previously Department of Energy) and the National Energy Regulator of South Africa (NERSA). The DMRE is responsible for establishing the policy, legal and regulatory framework for the energy sector. Its goal is to ensure the development, utilization and management of the energy resources in the country, aiming for the provision of secure, sustainable and affordable energy.[6] NERSA is mandated to regulate the electricity, piped gas and petroleum industries, it issues licences, sets and approves tariffs and charges, mediates disputes and ensures fair competition.[7] The South African National Energy Development Institute (SANEDI), carries out research and development activities to promote green energy technologies and energy efficiency.[8]

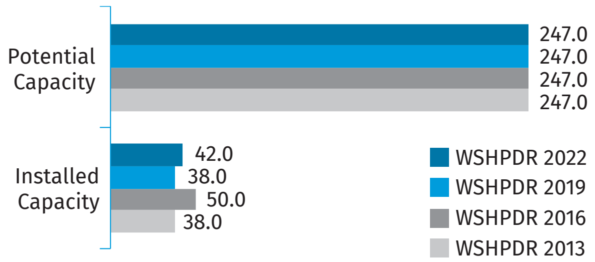
The electricity prices in South Africa depend on the supplier (ESKOM or municipality), the quantity of electricity used, the period (time or season) when the electricity is used, the volume of the supply, the geographic location of the customer, the voltage at which electricity is supplied and the cost of connecting to the supply. In 2021, average electricity prices rose to ZAR 1.349 ZAR/kWh (0.088 USD/kWh), an increase of nearly 16 per cent from 1.167 ZAR/kWh (0.076 USD/kWh) the previous year.[9,10]

SMALL HYDROPOWER SECTOR OVERVIEW

The Renewable Energy Independent Power Producers Procurement Programme (REIPPPP) is the main vehicle for the implementation of renewable energy technologies in South Africa, including small hydropower (SHP). During the first three bidding windows of the REIPPPP process, the maximum size of SHP plants was set at 10 MW. However, in the Request for Qualifications and Proposals for the third bidding window in June 2014, a new capacity limit of 40 MW was introduced for SHP.[11] A the same time, the draft Policy on Sustainable Hydropower Generation by the Department of Water and Sanitation (DWS) uses an upper limit of 10 MW.[12] As the DWS policy is not yet officially approved, the 40 MW as outlined in the REIPPPP process will be assumed as the current official definition of SHP in the country. However, for the purpose of comparison with the previous edition, this chapter will use data on hydropower up to 10 MW.

In 2021, the installed capacity of SHP up to 10 MW in South Africa stood at 42 MW, while potential was estimated at 247 MW.[13,14] Compared to the data cited in the *World Small Hydropower Development Report (WSHPDR) 2019*, potential capacity remained unchanged, while installed capacity increased by 1.8 per cent (Figure 4). The increase in installed capacity is due to one new SHP plant being commissioned in early 2021 on the As River.[13,15]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in South Africa (MW)**



Sources: Jonker Klunne & Barta,[13] Barta,[14] *WSHPDR 2019*,[15] *WSHPDR 2013*,[16] *WSHPDR 2016*[17]

Note: Data are for SHP up to 10 MW.

Although not documented to a great detail, historically SHP used to play an important role in the provision of electricity to urban and rural areas of South Africa, particularly in the municipalities situated along the foothills of the Drakensberg mountain range. The first provision of electricity to the cities of Cape Town and Pretoria was based on SHP and also smaller towns started local distribution of electricity through isolated grids powered by SHP plants. However, with the expansion of the national electricity grid and the cheap, coal-generated power supplied through the grid, large numbers of SHP plants were decommissioned. A typical example is the Sabie Gorge hydropower plant with three

450 kW turbines, which was commissioned in 1928 to serve the town of Sabie in Mpumalanga and closed in 1964 after the area had been connected to the national ESKOM grid.[18] Between 1917 and the mid-1950s, some 150 pico- to mini-hydropower plants were installed in South Africa, with a few surviving plants currently being refurbished.

After approximately 30 years of neglecting the hydropower potential of the country, the first new SHP plant was commissioned in 2009 in the Sol Plaatje Municipality in the Free State province. Since then, 13 other hydropower plants have been developed in the country.[19,20] A list of currently operational SHP plants is displayed in Table 1.

Table 1. **List of Operational Small Hydropower Plants in South Africa**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Kruisvallei	As River	4.700	N/A	Run-of-river	Red Rocket EPC	2021
KwaMadiba	Thina River	0.050	48	Run-of-river	Rural Local Council	2020
Doornkloof Reservoir	Tshwane City	0.009	N/A	Storage regulated, in-conduit	Tshwane Metropolitan Council	2020
Leliefontein	Drakenstein	0.555	N/A	Storage regulated, in-conduit PaT*	Drakenstein Municipality	2018
Cradle Moon Resort	Crocodile River	0.040	7	Run-of-river	Private	2018
Annlin Reservoir	Pretoria	0.150	N/A	Storage regulated, in-conduit PaT*	Tshwane Metropolitan Council	2017
Stortemelk	As River	4.400	14	Run-of-river	Renewable Energy Holdings	2016
L'Ormarins	Waterfall River	2.300	300	Run-of-river	Wine Estate Franschoek	2016
Neusberg	Kakamas	10.000	15.3	Run-of-river	Kakamas Hydro Electric Power	2015
Bloem Water Offices	Bloemfontein	0.096	N/A	Storage regulated, in-conduit	Bloem Water Board	2015
Pierre van Ryneveld Conduit	Pretoria	0.015	N/A	Storage regulated, in-conduit	Tshwane Metropolitan Council	2015
Badplaas Resort	Badplaas	0.150	10	Run-of-river	MBB Consulting	2013
Murludi Farm	Tulbagh	0.044	120	Run-of-river	Private	2013
Merino	As River	4.000	14	Run-of-river	Renewable Energy Holdings	2012
Mooi River Hydro	Mooi River	0.320	30	Run-of-river	Kruisfontein Farming Hydro	2012
Sol Plaatje	Liebenbergsvlei	3.000	11	Run-of-river	Renewable Energy Holdings	2009
Friedenheim	Crocodile River	3.600	62	Run-of-river	Friedenheim Irrigation Board	1987
Ncora	Tsomo River	2.400	40	Storage regulated	ESKOM	1983
Mtata First Falls	Umtata River	6.000	27.3	Storage regulated	ESKOM	1975
Steenbras Water Treatment Works	Steenbras Lower Reservoir	0.179	N/A	Storage regulated, in-conduit	Cape Town City Council	1946/ 1997

Source: Jonker Klunne & Barta,[13] Barta[14]

Note: *pumps as turbines

The South African Renewable Energy Database, as developed by the Council for Scientific and Industrial Research (CSIR), ESKOM and the Department of Minerals and Energy, investigated the available renewable energy resources in the country, including the potential for hydropower.[21] As a follow-up, the resources available for the Eastern Cape region were detailed as part of a three-year investigative project entitled "Renewable energy sources for rural electrification in South Africa". The primary objective of the latter project was to identify the commercially viable opportunities for rural electrification in the Eastern Cape Province of South Africa using wind power, hydropower and biomass.[22]

The 2002 Baseline Study on Hydropower in South Africa, which was developed as part of the Danish support to the South African Department of Minerals and Energy, investigated the installed capacities of hydropower in South Africa and the potential for new developments. The study concluded that twice as much as the current installed hydropower capacity below 10 MW can be developed in the rural areas of the Eastern Cape, Free State, KwaZulu Natal and Mpumalanga.[23] A later 2011 publication gave new insights into the potential of SHP in South Africa by including the hydropower potential of water transfer systems and gravity-fed water system, mentioning a total potential of 247 MW, of which 15 per cent has been developed so far.[14]

SHP plants in South Africa can be divided into the following groups: 1) grid-connected plants commissioned prior to the REIPPPP process; 2) plants installed under the REIPPPP process; 3) grid-connected systems that fall outside the

REIPPPP process; and 4) stand-alone systems not feeding into the national grid.

The grid-connected SHP plants introduced prior to REIPPPP include the First and Second Falls, Ncora, Lydenburg, Friedenheim and Bethlehem hydropower plants. Financed by the former Transkei Government, four hydropower plants were built between 1980 and 1984 in the Eastern Cape on the Mbashe and the Tsomo Rivers and later handed over to ESKOM: Colley Wobbles, First Falls, Second Falls and Ncora. The First Falls plant has two 3 MW units with the provision for a future third machine and the Ncora plant has a single 1.6 MW unit.[24] The Lydenburg plant commissioned in 1982 has one Gilkes Pelton turbine of 2.6 MW. The system is operated by MBB of Nelspruit under a contract with the local municipality.[20] The Friedenheim plant consists of two Sulzer Francis turbines of 1 MW each. It is owned by the members of Friedenheim Irrigation Board and operated on their behalf by engineering firm MBB. It has been running since 1987 and sells the bulk of the generated electricity through a power purchase agreement (PPA) to the local Mbombela Municipality.[20] Bethlehem Hydro Pty Ltd owns two SHP plants that are normally referred to as "Bethlehem hydro": the 3 MW Sol Plaatje power plant near the town of Bethlehem, which was commissioned in November 2009; and the 4 MW Merino power plant close to the town of Clarens. These two plants were the first addition of hydropower generation capacity in the last three decades.[20] Both the Sol Plaatje and the Merino installations are dependent on the flow regime of the Lesotho Highlands Water Project (LHWP), the water transfer project supplementing the Vaal Dam storage in the Gauteng province with water from Lesotho. The Kruisvallei SHP plant (4.7 MW) is constructed on the same water source and saw the start of commercial operation in February 2021.

The Neusberg plant of Kakamas Hydro Electric Power is the first run-of-river SHP plant to be delivered under the REIPPPP programme and is located on the Orange River near Kakamas in the Northern Cape province. Although the plant has three 4.01 MW Kaplan turbines, it delivers 10 MW of baseload power to the national grid in order to qualify under the old requirements of the REIPPPP.[25,26] The construction of the plant began in June 2013 and its operation began in 2015.[27] The Stortemelk hydropower plant was developed as a greenfield project by REH Project Development (formerly NuPlanet Project Development). The plant, commissioned in 2016, has an installed capacity of 4.5 MW and has won several rewards, including for its architecture.[28]

The future of grid-connected systems is closely linked to the Government's policy on renewable energy development. The allocation in the IRP2010 and the REIPPPP of 195 MW (up from the original 75 MW) of SHP capacity is less than the estimated potential and might therefore limit SHP development. The future for SHP in South Africa will see two main parallel tracks: grid-connected projects that will feed into the national electricity system and small-scale systems for private use (not feeding into the grid, irrespective of whether a grid connection is available or not). These tracks can be supplemented by a third category of isolated systems for rural electrification purposes. Several project developers indicated an intention to submit hydropower projects for the fifth and sixth bidding windows. These included some larger plants along the Orange River and in the Eastern Cape Province. A number of grid-connected systems are in operation at the moment in South Africa that either deliver power to the national utility or use the national grid to wheel power to its customers, for example, the 44 kW Murludi SHP plant and the 2.3 MW L'Ormarins SHP plant.[20] Development of small-scale plants are expected to grow based on the foreseen raise in electricity prices and decreased reliability of the grid. The development of SHP potential can be realized if the Government fully recognizes and adheres to the public-private partnership (PPP) implementation process in developing the renewable energy resources.[12]

Recent years have seen efforts to utilize existing water infrastructure for SHP development. For example, the water utility Rand Water has some 15 MW of SHP investigated at its four pressure break stations. Buffalo City has a significant hydropower potential, as assessed in 2013, at its water supply and sanitation infrastructure.[29] However, none of the investigated sites have been developed so far. In 2015, a 15 kW pilot plant was installed at the Pierre van Ryneveld reservoir in Pretoria as part of a University of Pretoria research project, while Bloemwater, the water distribution company of the city of Bloemfontein, commissioned a 96 kW system at the inlet of a water reservoir that is now providing power to the company's headquarters.[30] Most recently, a 9 kW conduit "otter" hydropower plant has been installed by the City of Tshwane at the Doornkloof reservoir. Yet another recent project is the Kwa Madiba (50 kW) community plant on the Thina River in the Eastern Cape Province, developed as community-managed rural electrification project .[31,32]

The actual installed SHP capacity of South Africa is substantially larger than can be reliably assessed. The primary reason for this is the large number of privately-owned SHP plants operating on private property and disconnected from both the national and local grids. These plants are often associated with mines and their collective installed capacity is estimated at approximately 80 MW. In some cases, hydropower units are also used to provide mechanical power in support of mining operations, rather than electricity generation. In most cases, the technical specifications of these plants and their operational status cannot be confirmed and they are thus excluded from the SHP total.[13]

While many additional SHP projects have been considered, there are currently only two in advanced stages of planning, at Mpompomo Falls and Bivane. In both cases, an environmental impact assessment (EIA) has been carried out.[14] Additional details on the two projects are provided in Table 2.

Table 2. **List of Ongoing Small Hydropower Projects in South Africa**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Developer*	*Development stage*
Mpompomo Falls	Barberton	2.0	N/A	Run-of-river	Rosatom/ Ganz Engineering Blue World Power Energy and Resources	EIA completed
Bivane	Vryheid	2.7	53	Storage	NuPlanet	EIA completed

Source: Jonker Klunne & Barta,[13] Jonker Klunne[20]

Note: Data as of 2021.

Besides the operational plants, South Africa has a number of existing, inactive small-scale installations that could be refurbished, such as Belvedere (2.1 MW), Ceres (1 MW), Hartbeespoort (potential up to 8 MW), Teebus (up to 7 MW) and others.[14, 20] The Hydro4Africa database includes over 20 previously operational sites that have been abandoned or fallen into disrepair, in addition to 60 sites identified as suitable for potential development.[21] A short list of sites suitable for refurbishment is provided in Table 3.

Table 3. **List of Selected Potential Small Hydropower Sites in South Africa**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site*
Buffelsfontein	Klerksdorp	3.83	1,463	Refurbishment
Belvedere	Blyde River	2.12	58	Refurbishment
Ceres	Ceres	1.00	140	Refurbishment
Parys	Vaal River	0.80	10	Refurbishment
Bakenkop	Piet Retief	0.67	50	Refurbishment

Source: Barta,[14] Jonker Klunne[20]

Note: Data as of 2021.

The SHP sector in South Africa has recently received support from a number of initiatives. The Water Research Commission of South Africa has been supporting the University of Pretoria in implementing in-flow hydropower in water transfer and distribution systems.[33,34] Recent research conducted in the sphere of conduit hydropower technology application in South Africa investigated and proposed a generic method of evaluating hydropower potential in water supply infrastructure.[35] The potable water distribution system, where the mechanical energy of excess water pressure can be converted into electric energy, has been investigated in the City of Polokwane.[36] Under the SA-LED programme by the United States Agency for International Development (USAID), the !Kheis Local Municipality and the eThekwini Metropolitan Municipality have been supported in developing their hydropower resources.[37,38]

RENEWABLE ENERGY POLICY

South Africa has a full suite of policies in place regulating the energy sector: White Paper on the Energy Policy of the Republic of South Africa (December 1998), the National Energy Act (Act No. 34 of 2008), the Electricity Regulation Act (Act No. 4 of 2006), White Paper on Renewable Energy (2003) and Renewable Energy IPP Procurement Programme 2015.[8]

The commitment of South Africa towards emissions reduction, as indicated in the Intended Nationally Determined Contribution (INDC) to the United Nations Framework Convention on Climate Change (UNFCCC), has triggered the development of a Government-backed renewable energy procurement programme. In 2010, the Department of Energy presented the Integrated Resource Plan (IRP2010), outlining the electricity generation mix for the period up to 2030. The policy-adjusted development plan approved by the Cabinet set a target of 17.8 GW of total installed capacity for renewable energy by 2030. The main source of hydropower, as per the IRP2010, will come from imported electricity (approximately 2.6 GW by 2030), while local, small-scale hydropower and landfill gas-based electricity share an allocation of 125 MW.[39] In October 2019, an updated IRP was approved by the Cabinet. This IRP2019 sees an increased allocation of installed capacity for renewable energy, in particular wind and solar power, with a target of 8,288 MW of total installed capacity for wind power and 17,742 MW for solar power by 2030. However, the only hydropower allocation refers to imported electricity from the Inga3 hydropower plant in the Democratic Republic of the Congo.[40]

The energy mix scenario of the IRP is implemented through the REIPPPP, which was launched by the Department of Energy in 2011, switching from the feed-in tariff system that had been created in 2009. In the context of South Africa, renewable energy is very competitive and at the current stage does not require additional financial incentivization, with independent renewable energy operators being able to sell electricity to consumers at substantially lower prices than those of ESKOM.[13] The first three bidding windows of this programme were procured by 2015, after which the signing of the PPAs for the windows 3.5 and 4 was stalled until early 2018, causing a decrease in the interest in the renewable energy sector of the country, including from foreign investors. The signing of 26 outstanding PPAs in April 2018 brought new hope for renewable energy development in the country. In October 2021 the winning bids for bidding window 5 were announced, but did not include any hydropower projects.[41,42]

The REIPPPP process has initiated substantial activity in the hydropower sector. In total, over 19 MW of installed hydropower capacity has been procured from three hydropower plants (Table 4).[41]

Table 4. **Hydropower Capacity Procured under the REIPPPP**

Bidding window	*Hydropower plants*	*Capacity (MW)*
1	None	-
2	Stortemelk Power Plant	4.4
	Neusberg Hydropower Project	10
3	None	-
3.5	None (this window was solar CSP only)	-
4	Kruisvallei Hydropower	4.7
5	None	-
	Total	**19.1**

Source: Smit,[41] Smith[42]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The effects of climate change on water resources is expected to be highly variable, with changes to average annual runoff by 2050 predicted to range between -13 per cent and +48 per cent. While this suggests the median impact scenario will generate a moderate increase in runoff on the national scale, regions may be unevenly affected, with the Western Cape region expected to experience a decline in average annual runoff of 13 per cent by 2050, while areas with a projected increase in runoff, such as the east coast, are at risk of flooding. The well-developed national water distribution system is expected to play a major role in mitigating the regional shifts in water supply.[43] Regionally, increased unpredictability in runoff is expected to create disruptions to hydropower generation in neighbouring countries, on which South Africa partially depends for its own electricity needs.[44] Potentially, these factors could encourage further development in South Africa of SHP that is integrated into the national water distribution grid, as a means of both utilizing the domestic water transfers for generation and building additional resilience against expected disruptions to electricity imports.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The constraints hampering more extensive development of SHP in South Africa include:

- Lack of relevant legislation slowing hydropower development at non-powered dams;
- Lengthy and expensive process for a successful EIA;
- The Water Use Permit (as per National Water Act/No. 36 of 1998) is sometimes difficult to obtain;
- Difficulties obtaining an acceptable PPA;
- Difficulties obtaining permission for access to, or crossing of, private or state land;
- Prior possession of all other permits is a prerequisite for obtaining the National Energy Regulator licence;
- Local banks are not in favour of financing SHP projects.

Factors enabling SHP development in South Africa include:

- A well-established bidding vehicle for renewable energy projects (REIPPPP), in 2022 entering its sixth successive period of activity;
- Extensive research carried out in-country on implementing SHP solutions on existing infrastructure, including water distribution and transfer systems;
- A significant number of assessed potential sites for SHP projects, as well as previously decommissioned plants in need of refurbishment.

With regard to the above constraints, the developers interested in installing SHP plants tend to focus on the development of projects situated along the existing water distribution networks (mainly at the local Government level as the water use environmental permits are already in place) according to the PPP principles. All in all, it is expected that SHP can play a small but important role in the future energy mix of the country. The creation of a representative body (e.g., the country or regional SHP Association) would enable potential hydropower developers in the negotiation and technology implementation processes.

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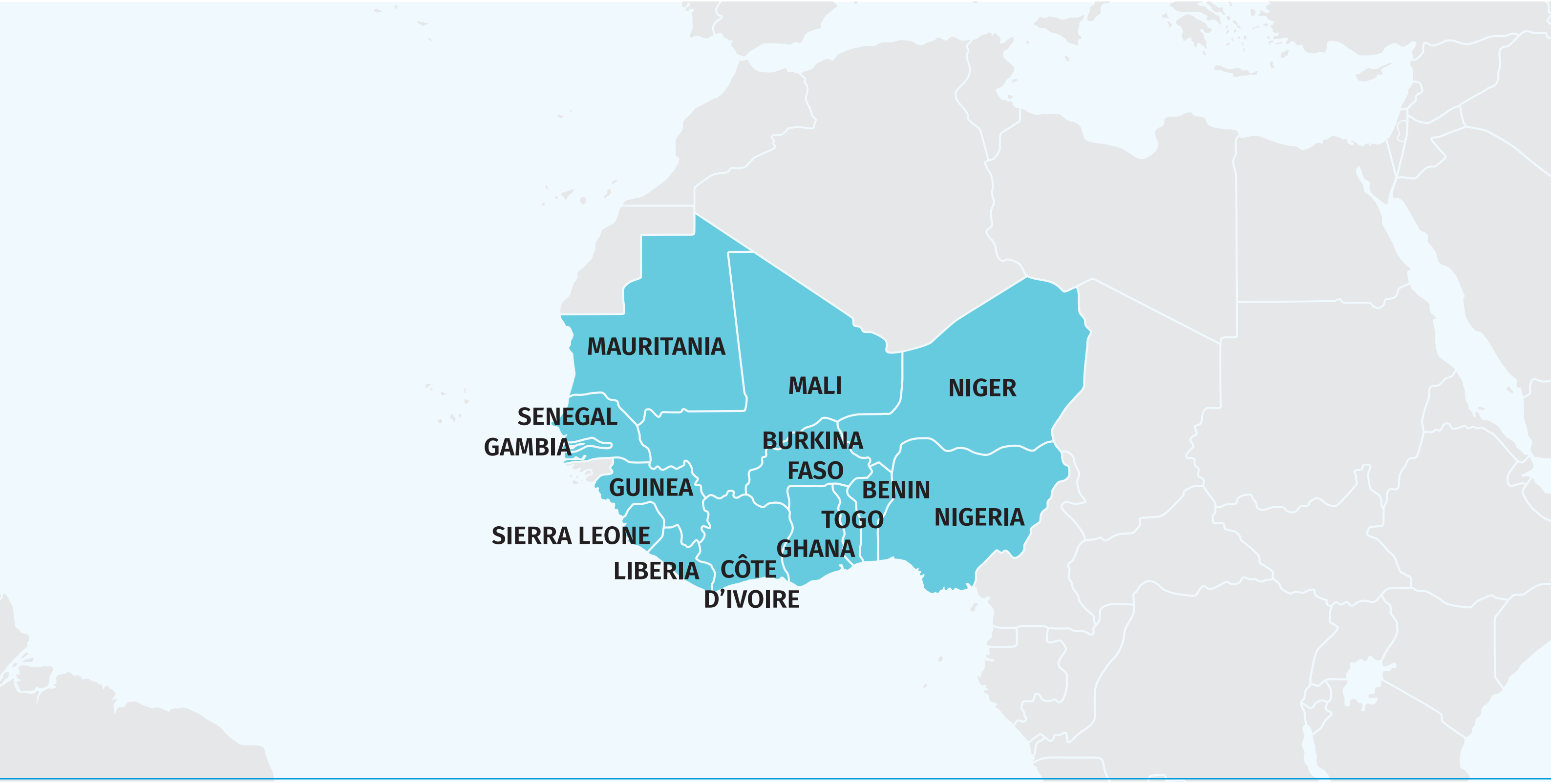


1.5. Western Africa

Countries: Benin, Burkina Faso, Cote d'Ivoire, Gambia, Ghana, Guinea, Liberia, Mali, Mauritania, Niger, Nigeria, Senegal, Sierra Leone, Togo

INTRODUCTION TO THE REGION

The Western Africa region straddles the Sahel zone and includes areas with arid and semi-arid climates, as well as areas abundantly supplied with water resources. Several countries in the region are major oil producers and thermal power is the leading source of electricity generation across most of Western Africa with the exception of Guinea and Liberia, where hydropower is the primary source of generation. In Burkina Faso, Côte d'Ivoire, Ghana, Mali, Nigeria, Sierra Leone and Togo, hydropower plays an important supplementary role, and some minor hydropower capacity exists in Benin. Gambia, Mauritania, Niger and Senegal lack hydropower of any kind.

The majority of countries in Western Africa have nationwide electricity access rates below 50 per cent, and a significant gap exists between the rates of electricity access in urban and rural areas. The development of renewable energy sources (RES) is increasingly prioritized by countries in the region, in part as a means of closing this gap. RES other than hydropower are represented in the region primarily by solar power and bioenergy, while Mauritania and Senegal have additionally invested in considerable wind power capacities. The Economic Community of West African States (ECOWAS) has been working to promote RES development in member states through the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE).

An overview of electricity sectors of the countries in the region is provided in Table 1.

Table 1. **Overview of Western Africa**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Benin	12	37	10	261	358	1	0
Burkina Faso	21	45	32	437	902	35	105
Côte d'Ivoire	26	49	N/A	2,229	10,613	879	3,481
Gambia	2	60	36	105	343	N/A	N/A
Ghana	32	86	74	5,172	18,189	1,580	7,252
Guinea	13	42	16	602	2,041	362	1,280
Liberia	5	28	8	193	226	92	124
Mali	20	51	16	884	3,952	315	1,463
Mauritania	5	46	3	587	863	N/A	N/A
Niger	24	19	13	380	555	N/A	N/A
Nigeria	206	55	26	17,823	33,489	2,017	8,211
Senegal	17	78	55	965	2,263	N/A	N/A
Sierra Leone	8	16	6	196	696	62	N/A
Togo	8	54	24	235	647	67	204
Total	**-**	**-**	**-**	**30,069**	**-**	**5,409**	**-**

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The most commonly used definition of small hydropower (SHP) in Western Africa is the definition established by the ECOWAS that includes plants with an installed capacity of up to 30 MW. This definition is adhered to in Benin, Gambia, Liberia, Mali, Nigeria and Sierra Leone. The up to 10 MW definition of SHP is used in Cote d'Ivoire and Senegal, while Guinea adheres to the up to 1.5 MW definition and Ghana to the up to 1 MW definition. No official definition of SHP exists in Burkina Faso, Mauritania, Niger and Togo.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Western Africa (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Benin	Up to 30 MW	0.5	95.0	0.5	5.0*
Burkina Faso	N/A	N/A	N/A	4.6	246.0
Côte d'Ivoire	Up to 10 MW	5.0	45.7	5.0	45.7
Gambia	Up to 30 MW	0.0	N/A	0.0	19.5
Ghana	Up to 1 MW	0.1	9.9	0.05	17.4
Guinea	Up to 1.5 MW	N/A	N/A	11.2	751.8
Liberia	Up to 30 MW	4.9	592.0	4.9	4.9**
Mali	Up to 30 MW	5.7	154.7	5.7	5.7**
Mauritania	N/A	0.0	N/A	0.0	N/A
Niger	N/A	0.0	N/A	0.0	8.0
Nigeria	Up to 30 MW	57.2	734.3	N/A	N/A
Senegal	Up to 10 MW	0.0	0.0	0.0	0.0
Sierra Leone	Up to 30 MW	12.2	N/A	12.2	639.0
Togo	N/A	N/A	N/A	1.6	137.0
Total	**-**	**-**	**-**	**45.7**	**1,880.0**

Source: *WSHPDR 2022*[1]

Note: *For SHP up to 1 MW. **Based on installed capacity.

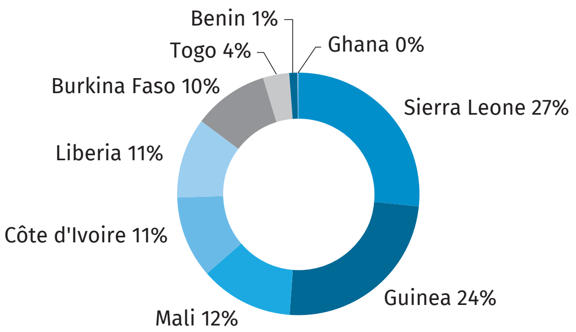
The total installed capacity of SHP up to 10 MW in Western Africa is 45.7 MW, while potential capacity is estimated at 1,880.0 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has increased by approximately 4 per cent due to the commissioning of one new SHP plant in Burkina Faso. Meanwhile, the estimated potential capacity of SHP up to 10 MW has more than tripled, mainly as a consequence of new data on the SHP potential in Burkina Faso and Guinea as well as a reinterpretation of available data on the SHP potential in Sierra Leone.

Overall, SHP plays a relatively small role in the electricity generation of the countries in Western Africa. Across much of the region, existing hydropower capacities mostly comprise large hydropower plants, although in Sierra Leone SHP accounts for nearly 20 per cent of all hydropower capacity, and the hydropower capacity of Benin is fully comprised of SHP. Several countries in the region have no hydropower of any kind and little prospect for hydropower development due to climatic conditions. New SHP construction in Western Africa in recent years has been very limited, with development focusing on other RES. The impact of the COVID-19 pandemic has likely played a role in constraining the resources available for the expansion of SHP capacity in the region during 2020–2022. Consequently, recent activity in the SHP sector has mainly consisted of studies collecting data on SHP potential.

It must be also noted that reliable data on the SHP sector for countries in Western Africa are often very difficult to acquire, both in the case of the countries surveyed in the current report and in the case of those not covered in the report due to lack of data. Consequently, the review of recent activities related to SHP development in the region is likely not exhaustive.

The national share of regional installed SHP capacity by country is displayed in Figure 1, while the share of total national SHP potential utilized by countries in the region is displayed in Figure 2.

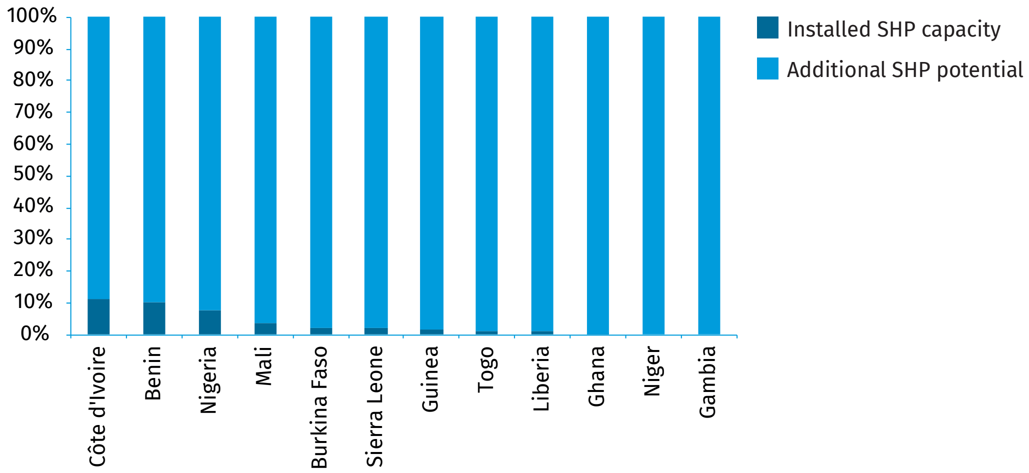
Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Western Africa (%)**



Source: *WSHPDR 2022*[1]

Note: Gambia, Mauritania, Niger and Senegal not included due to a lack of SHP capacity; Nigeria not included due to a lack of data on existing capacities for SHP of up to 10 MW.

Figure 2. **Utilized Small Hydropower Potential by Country in Western Africa (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP up to 10 MW, except in the case of Mali, Nigeria and Liberia, where the local definition is used due to lack of comprehensive data on the potential capacity of SHP up to 10 MW.

Benin has a single hydropower plant with an installed capacity of 0.5 MW. The potential capacity for SHP up to 30 MW is estimated at 95 MW, of which less than 1 per cent has been developed. Additionally, at least 5 MW of capacity for SHP up to 10 MW has been identified, of which 10 per cent has been developed. No recent activity in the country's SHP sector has taken place, although an upgrade to the existing SHP plant to raise its installed capacity to 1 MW has been considered.

The installed capacity of SHP up to 10 MW in **Burkina Faso** is 4.6 MW, provided by three SHP plants. The country's installed SHP capacity has recently doubled with the commissioning of a third plant in 2019. The potential capacity of SHP up to 10 MW is estimated at 246 MW on the basis of a recent study published in 2018, which identified a total of 80 potential SHP sites in the country. Specific plans exist outlining the construction of three additional SHP plants over the next several years.

The installed capacity of SHP up to 10 MW in **Côte d'Ivoire** is 5 MW, provided by a single SHP plant built in 1983, while the estimated potential SHP capacity is 45.7 MW, indicating that nearly 11 per cent has been developed. The country's installed SHP capacity has not changed in several decades. Additionally, the single existing SHP plant is non-operational and in need of refurbishment. No new projects in the SHP sector are under consideration, although some preliminary studies are planned.

There is no installed hydropower capacity in **Gambia** of any kind. The potential capacity for SHP up to 10 MW is estimated at 19.5 MW and remains entirely undeveloped. There are no SHP projects planned and recent activity in the SHP sector has been limited to updated studies of SHP potential, which have identified four potential SHP sites of up to 10 MW.

Ghana has a single SHP plant with an installed capacity of 0.045 MW. The potential capacity for SHP up to 10 MW is estimated at 17.42 MW, and at 9.9 MW for SHP up to 1 MW. Less than 1 per cent of SHP capacity under either definition has been developed. The sole operational SHP plant in the country was commissioned in 2020, and one earlier project has been on hold and requires extensive refurbishment. Sixty-nine potential sites up to 2 MW and another 12 sites up to 1 MW have been identified in the country, but there are no specific plans for new SHP construction.

The installed capacity of SHP up to 10 MW in **Guinea** is 11.2 MW, while the potential capacity has recently been estimated at 751.8 MW, indicating that approximately 1 per cent has been developed. There are five SHP plants in Guinea, with two undergoing renovation. As of 2021, feasibility studies were ongoing for the construction of four additional SHP plants with the support of the French Development Agency, and additional feasibility studies on several other potential sites are planned.

There are two operational SHP plants in **Liberia** with a total installed capacity of 4.86 MW. The potential capacity for SHP up to 30 MW in the country is estimated at 592 MW based on a study published in 2017, indicating that less than 1 per cent has been developed. No new construction in the SHP sector has taken place in recent years and there are currently no plans for additional SHP projects.

The installed capacity of SHP up to 30 MW in **Mali** is 5.7 MW, provided by a single plant. The potential capacity is estimated at 154.7 MW, indicating that nearly 4 per cent has been developed. Two new SHP plants are under development in the country through the Mini-Hydropower Plants and Related Distribution Networks Development Project, with environmental and social audits ongoing as of 2022. One additional SHP project has been initiated with the assistance of international development institutions.

There is no installed hydropower capacity of any kind in **Mauritania**, and no potential hydropower capacity has been documented. However, some limited SHP potential may exist in the southern part of the country.

There is likewise no installed hydropower capacity of any kind in **Niger**. A potential capacity of 8 MW for SHP of up to 10 MW has been identified but remains entirely undeveloped. There are no ongoing projects or plans for SHP development in Niger, although a large hydropower project of 130 MW is under construction.

The installed capacity of **Nigeria** for SHP up to 30 MW is estimated at 57.2 MW, with the decrease relative to the *WSHPDR 2019* reflecting more accurate data on existing SHP plants. There are 14 SHP plants operating in the country. The economically feasible potential capacity has been assessed at 734.3 MW from 278 potential sites, indicating that nearly 8 per cent has been developed, while the theoretical potential capacity is estimated at 3,500 MW. Several new SHP projects have been initiated in Nigeria over the last decade, but their status and stage of completion are unclear.

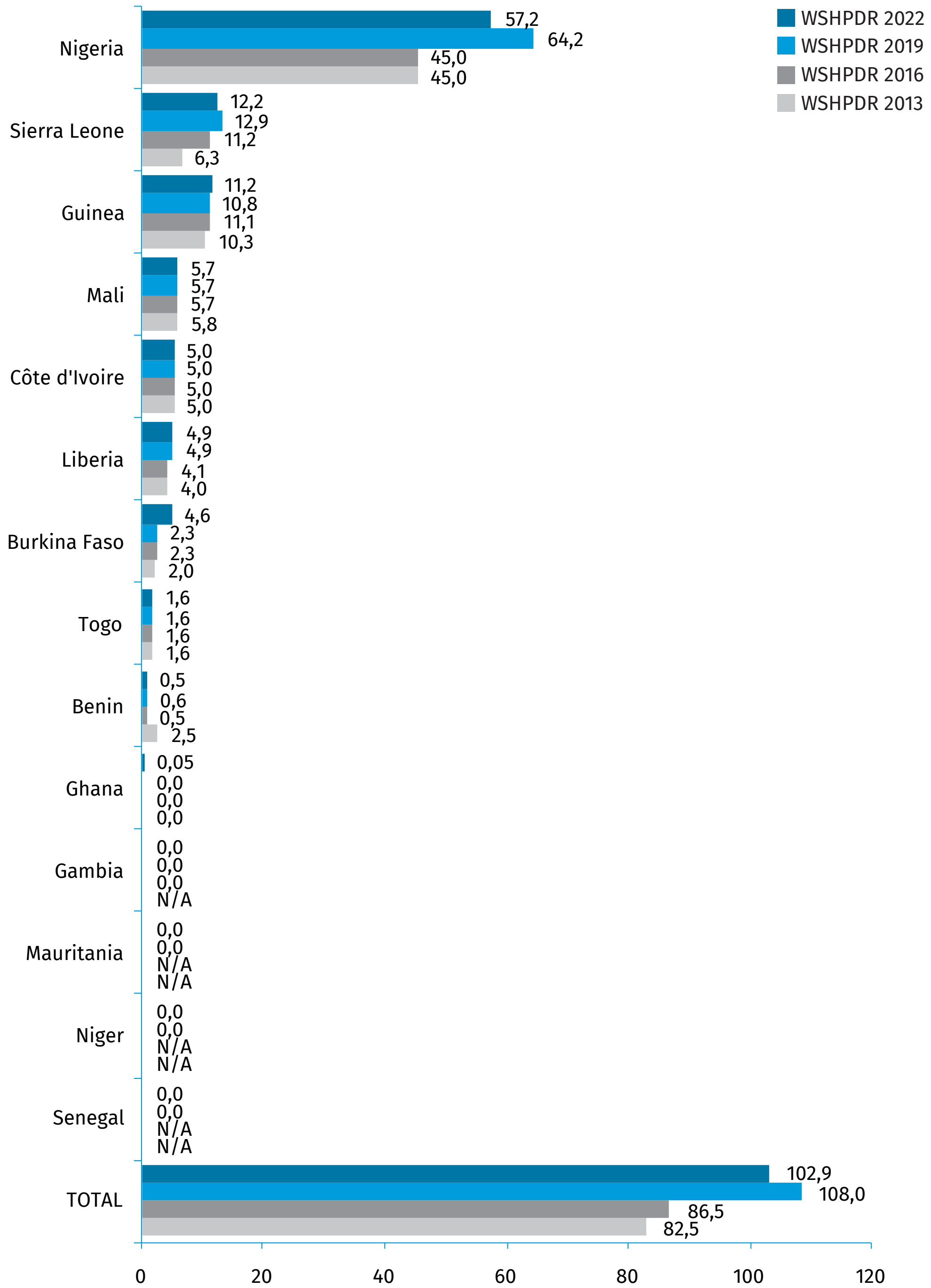
There is no installed hydropower capacity of any kind in **Senegal**, and no potential SHP capacity has been identified due to the flat topography of the country.

There are eight SHP plants of up to 30 MW in **Sierra Leone** with a total installed capacity of 12.15 MW. Potential capacity for SHP up to 30 MW is estimated at 639 MW, indicating that approximately 2 per cent has been developed. One new SHP plant with a capacity of 15.4 MW has been in development since 2016.

There is one SHP plant in **Togo** with an installed capacity of 1.6 MW. Potential capacity for SHP up to 10 MW is estimated at 137 MW, indicating that approximately 1 per cent has been developed, while potential for SHP up to 30 MW is estimated at 206 MW, of which less than 1 per cent has been developed. There are no ongoing SHP projects in the country, although the Government has identified seven potential sites for priority development.

Changes in the installed SHP capacities of the countries in the region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in Western Africa (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

Note: For SHP up to 10 MW, except in the case of Nigeria, where the local definition is used due to lack of data on the installed capacity of SHP of up to 10 MW.

Climate Change and Small Hydropower

Precipitation and runoff in Western Africa have been highly variable over the last century. Projections of future runoff in the region are likewise uncertain. Runoff in certain countries, including Guinea, is projected to decrease, while in Gabon and Sierra Leone it is projected to increase. Development of additional hydropower capacity in the region is seen as essential to reaching a clean energy mix and universal electricity access, but increasing the share of hydropower without assessing the potential impacts of climate change may increase the exposure of countries in the region to climate hazards and put their energy security at risk. Nevertheless, studies in the Upper Niger and Bani River basins have highlighted potential solutions aimed at reducing high streamflow variability and loss of water resources. In particular, results suggest that operating hydropower facilities as run-of-river projects could reduce evaporation by 20 per cent.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The development of SHP in **Benin** is complicated by low and unstable streamflow in the country's rivers, as well as by a lack of institutional and regulatory frameworks, incentives for SHP development and local technical capacity. Additionally, the country has prioritized RES other than SHP in its renewable energy strategy. At the same time, the considerable untapped SHP potential, particularly for SHP up to 30 MW, may form the basis for feasible SHP projects in areas where electricity access is lacking.

The development of SHP in **Burkina Faso** is likewise hampered by unpredictable streamflow and droughts that are exacerbated by ongoing climate change. The country lacks incentives for SHP development, and lack of reliable information on SHP potential likewise discourages investments. Government support has instead focused on solar power, which is seen as a more sustainable and profitable option. Enablers for SHP development include the recently identified additional SHP potential as well as the country's experience with hydropower in general, including technical capacity in the design, manufacture and operation of hydropower plants.

The key barriers to SHP development in **Côte d'Ivoire** are the lack of comprehensive data on potential SHP sites and the country's heavy focus on the development of large hydropower. At the same time, the SHP potential in the country is considerable, and SHP could play an expanded role as the basis for micro-grids used to extend electricity access to remote areas.

Development of SHP in **Gambia** is hampered by the low heads found across the country's hydrology system, which complicates any hydropower development. Additional barriers include the institutional and operational weaknesses of the country's distribution and transmission system operator and high electricity tariffs, which make electricity unaffordable for large segments of the population and thus limit the economic feasibility of potential projects. Enablers include recent studies on SHP potential and the availability of incentives for SHP development in the form of feed-in tariffs (FITs).

Barriers to SHP development in **Ghana** include weak institutional and regulatory frameworks, limited local expertise and awareness of SHP, lack of funding opportunities and climate change impacts that interfere with hydropower generation. At the same time, a wide array of potential SHP sites has been identified in the country. The overall policy direction in Ghana is favourable towards SHP development and includes support in the form of FITs and other incentives.

Barriers to SHP development in **Guinea** include a lack of financial support and the low marketability of electricity from SHP due to the poverty of the rural population, as well as institutional shortcomings and lack of technical capacity in the sector. However, the undeveloped SHP potential in the country is considerable and well-documented. Some of this potential may be realized with the aid of international development agencies.

Development of SHP in **Liberia** is hampered by a lack of a comprehensive renewable energy policy or strategies for SHP development, deficient electricity grid, lack of local technical expertise and insufficiently detailed hydrological data. At the same time, there is considerable and well-documented untapped SHP potential in the country and recent government documents have made mention of plans to accelerate SHP development.

In **Mali**, SHP development is complicated by high investment costs, variability in river flow caused by climate change and concerns over environmental impacts, which have generated opposition from indigenous groups. Enablers for SHP development include the considerable untapped SHP potential and the availability of international financing, as well as interest on the part of the Government in promoting mini-grids and the job creation potential of SHP projects.

The lack of identified hydropower potential in **Mauritania** is a major impediment to SHP development in the country. The

Government has consequently focused on developing other RES such as solar power and wind power. However, if properly assessed, the suspected SHP potential in the southern part of the country may be used to provide power to isolated rural communities.

In **Niger**, the lack of experience with hydropower development and the country's irregular rainfall patterns, exacerbated by climate change, are the major obstacles to SHP development. Additional obstacles include a lack of a comprehensive renewable energy policy and dependence on fossil fuels for electricity generation. At the same time, the identified SHP potential could provide a means of improving electricity access, particularly if regional expertise in SHP could be attracted to develop this potential.

Barriers to SHP development in **Nigeria** include inadequate policy, institutional and regulatory frameworks, high investment costs and insufficient local technical capacity, lack of interest from the private sector in SHP development and limited access to available data on SHP potential. The main enablers are the very considerable and well-documented SHP potential and the urgent need to extend electricity access to remote parts of the country.

The main barrier to SHP development in **Senegal** is the country's flat topography and lack of any SHP potential. At the same time, if any SHP potential could be identified, it would benefit from a strong institutional framework and government support for RES development, which includes tax incentives and FITs.

Barriers to SHP development in **Sierra Leone** include a lack of funding and lack of local technical and manufacturing capacity, as well as high electricity tariffs that make electricity cost-prohibitive for many segments of the population. However, the country's considerable potential SHP capacity could be realized through international assistance and direct foreign investment, which have already made a positive impact in the solar power sector.

In **Togo**, obstacles to SHP development include barriers to the entry of private investors, institutional and regulatory weaknesses, relatively high up-front costs compared to diesel generators and lack of international funding opportunities. At the same time, the country has significant untapped SHP potential due to favourable hydrological conditions, and the Government has prioritized SHP development as part of rural electrification efforts, as well as attracting private investors to the SHP sector.

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Benin

Salim Chitou, West-African Energy Information System

KEY FACTS

Population	12,114,193 (2020)[1]
Area	114,763 km^2[2]
Topography	The topography of Benin can be subdivided into five regions: the flat, low and sandy coastal region; the central hilly plain rising gradually to 200–400 metres from south to north; the Kandi Basin in the north-east, which is a plain drained by the Sota River and its tributaries; the Atakora Mountains lying in the north-west and peaking at Mount Sokbaro (658 metres); and the vast plains of Gourma in the extreme north-west.[2]
Climate	The climate of Benin is strongly influenced by the West African Monsoon. In the south, where the monsoon regime predominates (humid winds from the south-west), the climate is of the subequatorial type and is characterized by two rainy seasons and two dry seasons. In the north of the country, where the influence of the monsoon is more moderate, the climate is tropical continental, with one rainy season and one dry season. Air temperatures average 27.2 °C, with absolute maximums that can exceed 45 °C in the north.[3]
Climate Change	Benin is highly vulnerable to climate change. Since 1960, average temperature increased by 1.1 °C. The number of hot days per year increased by 39, whereas the frequency of cold days and nights decreased significantly. Annual precipitation decreased by 180 mm, resulting in more intense droughts. At the same time, rains intensified, leading to soil erosion and floods. The mean annual temperature is projected to increase by 1.0–3.0 °C by the 2060s and by 1.5–5.1 °C by the 2090s.[4]
Rain Pattern	Average annual precipitation ranges between 700 mm in the extreme north and 1,400 mm in the extreme south-east. There is also a transitional zone, where, depending on the year, the rainfall regime is bimodal as in the south of the country or mono-modal as in the north, with an average annual rainfall of 1,000–1,200 mm.[4]
Hydrology	Hydrologically, Benin can be divided into four major basins: the Niger Basin, the Ouémé-Yéwa Basin, the Volta Basin and the Mono-Couffo Basin. The Niger Basin comprises the Niger (120 kilometres), Mékrou (410 kilometres), Alibori (338 kilometres) and Sota (250 kilometres) Rivers. The Ouémé-Yéwa Basin includes the Ouémé River (510 kilometres) and its main tributaries the Okpara (200 kilometres) and Zou (150 kilometres), as well as Porto-Novo Lagoon (35 km^2) and Lake Nokoué (150 km^2). The Volta Basin includes the Volta (1,500 kilometres) and Pendjari (380 kilometres) Rivers. Finally, the Mono-Couffo Basin includes the Mono (100 kilometres) and Couffo (190 kilometres) Rivers, lakes Ahémé (78 km^2) and Toho (15 km^2) and Cotonou and Grand-Popo (15 km^2) Lagoons.[4]

ELECTRICITY SECTOR OVERVIEW

The total installed electricity capacity of Benin in 2019 was 261 MW, with over 98 per cent coming from thermal power. There is one hydropower plant installed on the territory of Benin, the 0.5 MW Yeripao plant, as well as 3.75 MW of capacity from micro-scale solar photovoltaics (PV) (Figure 1).[5] An additional 32.5 MW comes from the 65 MW Nangbeto hydropower plant installed on the Mono River in Togo, which is jointly owned by Benin and Togo under the bi-national Communauté Électrique du Benin (CEB).[5,6]

Total electricity generation in 2019 in Benin amounted to 357.5 GWh, coming predominantly from thermal power and to a lesser extent from solar power (Figure 2).[5] Conversely, the Yeripao hydropower plant did not contribute to the country's electricity supply as it remains offline.

Figure 1. **Installed Electricity Capacity by Source in Benin in 2019 (MW)**

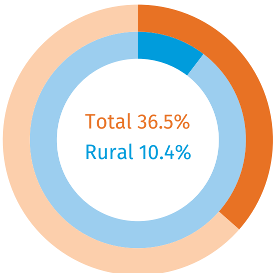
Source: SIE-Benin[5]

Figure 2. **Annual Electricity Generation by Source in Benin in 2019 (GWh)**

Source: SIE-Benin[5]

Total access electricity in the country in 2020 stood at approximately 37 per cent, including 65 per cent in urban areas and 10 per cent in rural areas (Figure 3).[7]

Figure 3. **Electrification Rate in Benin in 2020 (%)**



Source: DGRE[7]

The limited capacity of the country's energy sector to meet demand remains a major challenge for the public authorities. Until recently, the country's energy situation was characterized by a recurrent crisis marked by insufficient electricity supply, the relatively high cost of electricity, low energy efficiency, not to mention the weak development of alternative energy sources. These factors have made the sector particularly vulnerable and have negatively impacted the national economy. Hence, one of the key development objectives for Benin is to increase electricity production. The main recent development was the construction of the 127 MW Maria-Gléta thermal power plant, which was launched in 2019.[8] Benin and Togo jointly planned to develop the 147 MW Adjarala hydropower plant on the Mono River, however, the project stalled due to financing issues.[9] Currently, the Government plans to develop the 140 MW Glo-Djigbe thermal power plant, 100 MW of solar power capacity, the 128 MW Dogo hydropower plant and other projects.[10]

The main players of the electricity sector in Benin are the Ministry of Energy and the structures under its supervision, the Electricity Regulatory Authority (ARE), the Benin Agency for Rural Electrification and Energy Management (ABERME), the regional cooperation institutions, private structures responsible for the production, transmission, distribution and marketing of electrical energy and energy efficiency as well as consumer associations and professional organizations.

Electricity tariffs in Benin are uniform across the entire territory and remained unchanged between 2006 and 2019, but were adjusted for 2020 and 2021 (Table 1).

Table 1. **Low-Tension Electricity Tariffs in Benin in 2019–2021**

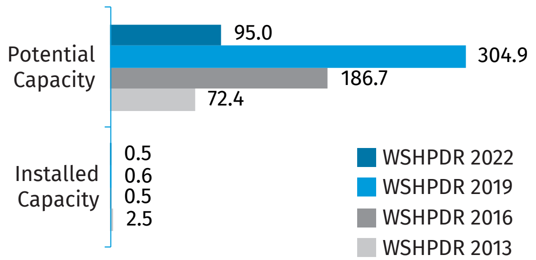
	2019 tariffs		*2020 tariffs*		*2021 tariffs*	
Consumer category	*Electricity usage (XOF/kWh (USD/kWh))*	*Fixed charge (XOF/kVA/M (USD kVA/M))*	*Electricity usage (XOF/kWh (USD/kWh))*	*Fixed charge (XOF/kVA/M (USD kVA/M))*	*Electricity usage (XOF/kWh (USD/kWh))*	*Fixed charge (XOF/kVA/M (USD kVA/M)*
Domestic:						
<20 kWh	78	500	78	500	86	500
0–250 kWh	109	500	114	500	125	500
>250 kWh	115	500	134	500	148	500
Professional and prepaid	111	500	114	500	125	500

Source: SBEE[11]

SMALL HYDROPOWER SECTOR OVERVIEW

The official definition of small hydropower (SHP) in Benin is up to 30 MW. There is one SHP plant in Benin, the 0.5 MW Yeripao plant (Table 2).[5] In 2016, the plant generated 5.3 MWh and in 2017, 1.2 MWh, with no generation since then. Renovations have been considered for the Yeripao plant to reach a capacity of 1 MW, however, the project was not realized. The SHP potential up to 30 MW is estimated at approximately 95 MW.[12] Compared to the *World Small Hydropower Development Report* (*WSHPDR*) *2019*, the installed capacity decreased based on more accurate data. The potential estimate also decreased based on a more recent assessment (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Benin (MW)**



Sources: SIE-Benin,[5] ECREEE,[12] *WSHPDR 2013*,[13] *WSHPDR 2016*,[14] *WSHPDR 2019*[15]

A number of studies of the hydropower potential in Benin have been carried out identifying a range of potential sites of various scale. In 2012, the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) reported a total potential of 304.9 MW from 99 sites of up to 30 MW each, with the estimate being based on a number of earlier inventories.[16] Another assessment was carried out in 2015 under the ECOWAS Small-Scale Hydropower Programme using Geographic Information Systems (GIS) and identified 5 MW of potential for sites of up to 1 MW and 90 MW of potential for 1–30 MW sites.[12] The present chapter uses the more recent estimate of the potential.

Table 2. **List of Existing Small Hydropower Plants in Benin**

Name	*Locatiion*	*Capacity (MW)*	*Operator*	*Launch year*
Yeripao	Yeripao, Natitingou	0.5	Benin Electric Energy Company (SBEE)	1997

Source: ECREEE[16]

RENEWABLE ENERGY POLICY

Benin is endowed with significant renewable energy resources, however, only a minor share of the existing potential is currently used. This issue is addressed in the National Policy for the Development of Renewable Energy (PONADER) 2020–2030, which was adopted by the Government on 14 October 2020. The ambition of the PONADER is in particular to improve knowledge of the renewable energy resources in the country, to promote technologies for the assessment of the existing potential, to reduce energy imports and to increase energy access in rural areas. The PONADER also set the target of reaching 20–30 per cent of electricity generation from renewable energy sources and 30–40 per cent of total installed capacity.[17] The Policy is aligned with the Government Action Programme (PAG), which among other objectives envisages improving the legislative and regulatory system in each sector in order to attract private investments.[10]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Several barriers to SHP development exist in Benin, including:

- Lack of local hydropower equipment, supply and local manufacturers;
- Lack of an institutional and regulatory framework facilitating licences, permits, authorizations and buy-back tariffs;
- Low-flow and drying rivers;
- Independent power producers have not yet explored the option of SHP;
- Lack of a feed-in tariff (FIT) for SHP;
- Policy focus on other renewable energy sources and large-scale hydropower.

At the same time, SHP development in the country could be possible given the following factors:

- Significant SHP potential remains untapped;
- Low electrification rates, particularly in rural areas.

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Burkina Faso

International Center on Small Hydro Power (ICSHP)

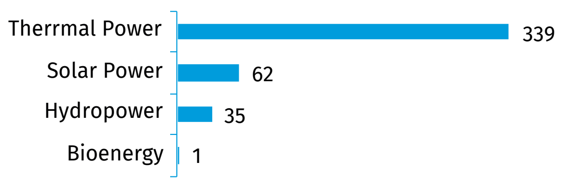
KEY FACTS

Population	20,903,278 (2020)[1]
Area	274,220 km^2 [2]
Topography	Burkina Faso is a landlocked country, bounded by Mali, Niger, Benin, Côte d'Ivoire, Ghana and Togo. It is situated on an extensive plateau, which is defined by a grassy savanna in the north that gradually becomes sparse forests in the south. A sandstone massif that covers most of the land is where the highest point of the country is, Mount Tena Kouron, at 747 metres. The lowest point of the country is the Black Volta River at 200 metres above sea level.[3]
Climate	Due to its location, Burkina Faso has a dry tropical climate. The climate alternates between a short rainy season and a long dry season. The country has three climatic zones: the Sahelian zone in the north, the North-Sudanian zone in the centre, and the South-Sudanian zone in the south.[4] April has the highest average temperature at 32 °C and the lowest average temperature is in January, at 25 °C.[5]
Climate Change	Burkina Faso is vulnerable to the impacts of climate change, particularly deforestation, desertification, low rainfall and extreme weather events. By 2050, a 1.4–1.6 °C rise in temperatures is expected in Burkina Faso.[6] By 2080–2099, temperature is projected to increase by 3–4 °C, which is substantially higher than the global.[5] Despite little projected change in annual precipitation sums, future dry and wet periods are likely to become more extreme.[6]
Rain Pattern	The Sahelian zone receives less than 600 mm of average annual rainfall. The North-Sudanian zone receives an average annual rainfall between 600 mm and 900 mm. The South-Sudanian zone receives an average annual rainfall above 900 mm.[3] Rainfall is heaviest in August, with an average of 231 mm, while the average annual precipitation is 816 mm.[5]
Hydrology	The three principal rivers are Black Volta (Mouhoun), the Red Volta (Nazinon) and the White Volta (Nakambé). These rivers all converge in Ghana to form the Volta River. The Oti, another tributary of the Volta, rises in south-eastern Burkina Faso.[6]

ELECTRICITY SECTOR OVERVIEW

In 2019, total electricity production in Burkina Faso reached 902 GWh, of which thermal power plants accounted for 82 per cent (Figure 1). The country is still highly dependent on electricity imports from Cote d'Ivoire, Ghana and Togo, having imported approximately 1,087 GWh in 2019.[7]

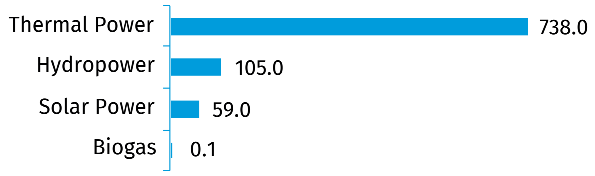
Figure 1. **Annual Electricity Generation by Source in Burkina Faso in 2019 (GWh)**



Source: ARSE[7]

In 2020, the total installed capacity in Burkina Faso was 437 MW, with thermal power (heavy fuel oil and distillate diesel oil) making up 78 per cent of the total and renewable energy sources accounting for the remaining 22 per cent (Figure 2).[8] Over the past years, the country has seen a significant increase in solar power capacity, with a number of new projects launched.[9]

Figure 2. **Installed Electricity Capacity by Source in Burkina Faso in 2020 (MW)**



Sources: IRENA[8]

The overall electricity losses in the country's electricity system amounted to 303 GWh in 2019, compared to 290 GWh in 2018, with most of the losses taking place in the distribution network. The overall efficiency of the electricity network improved from 84.4 per cent in 2018 to 84.8 per cent in 2019.[7]

The electricity demand of the country is constantly increasing and there are several projects under implementation aimed at improving the supply (Table 1). In 2019, agreements were signed with six independent power producers (IPPs) for the construction of solar power plants with a combined capacity of 140 MW.[7] The thermal power plant in Fada was also launched in 2020, contributing 7.75 MW to the country's installed capacity.[10] The country has also planned several other projects until 2030 as a commitment under its Nationally Determined Contribution.[11]

Table 1. **List of New Electricity Generation Projects under Implementation in Burkina Faso in 2021**

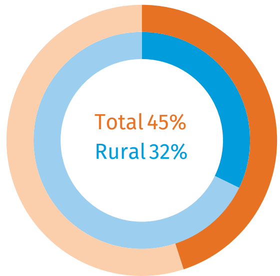
Project	*Planned capacity (MW)*	*Generation type*	*Connection*
Kossodo — expansion	55.0	Diesel thermal	Ongrid
Koudougou	20.0	Solar PV	Ongrid
Kaya	10.0	Solar PV	Ongrid
Kodeni	38.0	Solar PV	Ongrid
Pâ	30.0	Solar PV	Ongrid
Kalzi	36.0	Solar PV	Ongrid
Kodeni	18.0	Solar PV	Ongrid
Zano	24.0	Solar PV	Ongrid
Dedougou	30.0	Solar PV	Ongrid
Gosin (Ouaga Nord-West)	42.0	Solar PV	Ongrid
Gaoua	1.0	Solar PV	Ongrid
Diapaga	2.0	Solar PV	Ongrid
Dori	6.0	Solar PV	Ongrid

Source: ARSE,[7] MAN[12]

The energy sector in Burkina Faso is controlled by the Ministry of Energy, Mines and Quarries. The Regulatory Authority of Energy Sector (ASS) is responsible for regulation, control and monitoring of operators in the energy sector, while the Electricity Sector Regulatory Authority (ARSE) is the electricity sector regulator. The National Electricity Company of Burkina Faso (SONABEL) is the state-owned utility responsible for electricity generation, transport, distribution, import and export. As per the Electricity Law promulgated in 2017, SONABEL has lost monopoly in all subsectors except for electricity transport. The Rural Electrification Agency (ABER), created to replace the Rural Electrification Fund (FDE), aims to promote rural electrification in the country. The National Agency for Renewable Energy and Energy Efficiency (ANEREE) promotes and coordinates all operations aimed at promoting renewable energy and energy efficiency.[9]

Burkina Faso is one of the least electrified countries globally.[13] However, the electrification rate has been steadily increasing since 2010. In 2018, 45 per cent of the population had access to electricity (Figure 3). In urban centres, the electrification rate was 75 per cent, while in rural areas it was 32 per cent.[7] While more recent data on the country's electrification rate are not available, there has been a significant increase in rural electrification form 3 per cent in 2017 to 32 per cent in 2018.[7] By 2030, the Government aims to reach 95 per cent electricity access, including 50 per cent in rural areas, as well as 100 per cent and 65 per cent access to clean cooking solutions in urban and rural areas, respectively.[13]

Figure 3. **Electrification Rate in Burkina Faso in 2018 (%)**



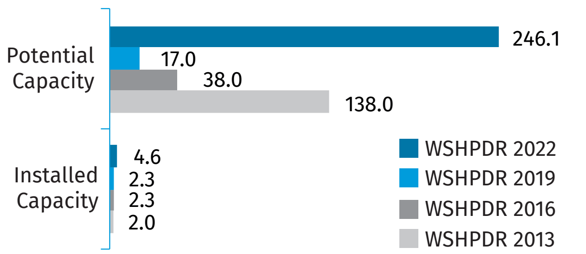
Source: ARSE[7]

The average electricity selling price in 2019 was 116.16 CFA/kWh (approximately 0.20 USD/kWh), 5 per cent less than in 2015. This was still below the cost of electricity generation of 139.11 CFA/kWh (0.24 USD/kWh), which results in a subsidy of CFA 22.96 (USD 0.04) per kWh consumed.[7]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in Burkina Faso. For the purposes of this chapter, SHP will be considered as plants up to 10 MW. As of 2021, there were three operational SHP plants with a combined capacity of 4.6 MW: Niofila (1.5 MW), Samandeni (2.6 MW) and Tourni (0.5 MW) (Table 2).[14,15,16] The change in installed capacity compared to the *World Small Hydropower Development Report (WSHPDR) 2019* is due to the launch of the Samendeni plant in 2019 (Figure 4). The estimate of the SHP potential has also increased based on a more recent study, which suggests a total potential of 246.1 MW. This includes 232.9 MW from 42 potential sites of 1.01–10 MW of capacity and 13.2 MW from 38 sites of 0.1–1 MW of capacity.[17]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Burkina Faso (MW)**



Source: IRENA,[14] Africa Energy Portal,[15] Moner-Girona et al.,[16] Korkovelos et al.[17] *WSHPDR 2013*,[18] *WSHPDR 2016*,[19] *WSHPDR 2019*[20]

The Samendeni hydropower plant was launched in 2019 and is part of the Samendeni Valley Integrated Development Programme, an initiative by the Government of Burkina Faso.[15] The Government also expressed interest in conducting feasibility studies for the development of another three hydropower plants: the 5.0 MW Gongourou plant, 5.1 MW Bontioli plant and 7.8 MW Bon plant. The Ministry of Energy, Mines and Quarries declared the aforementioned projects as a priority for the sustainable development of the country. Commitments have also been made towards the construction of the Gongourou and Bontioli plants.[14]

Most of the hydropower projects planned or under construction are located on the Black Volta River.[21] Table 3 offers more information with regards to the Government's development initiatives in the hydropower sector.

Table 2. **List of Existing Small Hydropower Plants in Burkina Faso**

Name	*Installed capacity (MW)*	*Type*	*Launch year*
Samandeni	2.6	Reservoir	2019
Niofila	1.5	Run-of-river	1996
Tourni	0.5	Run-of-river	1996

Source: IRENA,[14] Africa Energy Portal,[15] Moner-Girona et al.[16]

Table 3. **List of Planned Hydropower Projects in Burkina Faso as of 2021**

Name	*Potential capacity (MW)*	*Planned launch year*	*Status*
Noumbiel	60.0	2025	Planned
Aval	14.0	2023	Committed
Bougouriba	12.0	2025	Planned
Folonzo	10.8	2022	Committed
Bontioli	5.1	2022	Committed
Gongourou	5.0	2022	Committed

Source: IRENA[14]

RENEWABLE ENERGY POLICY

The National Policy for Sustainable Economic and Social Development outlined the strategy and actions of the Government of Burkina Faso for the period 2016–2020 to achieve its development objectives. The strategy mentions opting unequivocally for a transition towards green and renewable energy, in particular solar energy. In 2017, production and distribution of electricity in the country became open to private investors and SONABEL no longer has a monopoly over electricity production. Although power generation has been opened to the private sector, very few private investments have been made so far. As part of the Government's efforts to promote renewable energy and energy efficiency, ANEREE was established in 2016.[16]

Information in the field of renewable energy policy in Burkina Faso is enclosed in the Energy Sector Policy for the years from 2014 to 2025. The objectives the Government set in the Renewable Energy and Energy Efficiency Action Plans envisage Burkina Faso reaching 50 per cent renewable energy in the electricity mix by 2030, excluding biomass production.[13]

SHP projects are generally seen as more environmentally and socially acceptable in Burkina Faso and do not face negative social reaction as is often the case with large hydropower plants. The Government of Burkina Faso has been shown to be more invested in developing solar photovoltaic (PV) systems to increase electrification, particularly in rural areas, due to the country's climate which favours solar PV.

COST OF SMALL HYDROPOWER DEVELOPMENT

Based on the Bontioli, Gongourou and Samandéni projects, the investment costs for SHP projects in the country have been estimated at 11,006 USD/kW and the annual operation and maintenance cost at 330.2 USD/kW.[14]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are multiple barriers concerning SHP development in Burkina Faso. The most relevant ones include:

- Access to water as well as unpredictable climate conditions, with droughts affecting the regular flow of rivers and negatively influencing the profitability of potential SHP projects;
- The Government has mainly focused on solar power development in recent years, which is seen as a more sustainable and profitable solution, while SHP dissemination is not a priority;
- Lack of financial incentives such as feed-in tariffs and lack of sufficient information in the sector to attract potential private investors;
- Lack of reliable data from feasibility studies due to lack of funding and financial difficulties.[7,19]

Enablers for SHP development in Burkina Faso include:

- The hydropower sector development, including SHP projects, is actively encouraged by the Government, with a number of committed and planned SHP projects;
- Due to a number of existing hydropower plants in the country, there is experience in construction and operation of hydropower plants, as well as a qualified workforce for design, construction, operation and maintenance.

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Côte d'Ivoire

N'guessan Pacôme N'Cho, Ministry of Petroleum, Energy and Renewable Energy

KEY FACTS

Population	25,716,544 (2019)[1]
Area	322,632 km^2[2]
Topography	Côte d'Ivoire is characterized by low terrain; the lands consist largely of plateaus and plains. The west highlands have few peaks beyond a thousand metres and the highest peak is Mount Nimba at 1,752 metres. In the remainder of the country, elevations generally vary between 100 and 500 metres, while most plateaus are approximately 200–350 metres.[3]
Climate	There are three main climatic regions: the equatorial coast in the south, the tropical forest in the middle and the semi-arid savannah in the north. Temperatures range from 10 °C to 40 °C, averaging 25-30 °C, but the country is generally subjected to large variations in temperature between the north and south and throughout the year. The south is generally warmer with high humidity between 80 and 90 per cent. The north is generally cooler with lower humidity between 40 and 50 per cent. Temperatures in the north change by up to 20 °C both daily and annually.[2]
Climate Change	Côte d'Ivoire is not yet seriously affected by climate change, but the balance could tip at any moment and harm the country's economy. Côte d'Ivoire could become one of the African continent's champions in adapting its economy to the phenomenon and mitigating its effects. Like the vast majority of countries on the African continent, the nation's contribution to the greenhouse effect is marginal. By 2050, it is projected that the country will be confronted with the combined effect of increase in temperatures (+2 °C), variation in rainfall (-9 per cent in May and +9 per cent in October), and rising sea levels (30 cm).[4]
Rain Pattern	The south has variable rainfalls between 2,100 mm and 2,500 mm. The middle central region has lower rainfalls of approximately 1,100 mm. The north is subject to a single rainy season lasting from April to October and peaking in August. The rainfall is higher in the north-west (approximately 1,600 mm) than in the north-east (approximately 100 mm). The western mountainous region is characterized by a nine-month rainy season (from February to October) with rainfall between 1,600 mm and 2,300 mm.[5]
Hydrology	The river system of Côte d'Ivoire has four main basins: the Cavally (700 km long with a drainage basin of 15,000 km^2); the Sassandra (650 km long with a drainage basin of 75,000 km^2); the Bandama (1,050 km long with a drainage basin of 97,000 km^2); and the Comoé, (1,160 km long with a drainage basin of 78,000 km^2). There are also several small coastal rivers: the Tabou, San-Pedro, Niouniourou, Boubo, Agnéby, Mé, Bia and Tanoé; and other smaller rivers such as the Gbanhala, Baoulé, Bagoué, Dégou, Kankélaba, Koulda, Gbanlou, Gougoulo and Kohodio.[6]

ELECTRICITY SECTOR OVERVIEW

Biomass dominates the energy sector of Côte d'Ivoire accounting for up to 70 per cent of overall energy needs.[7] Biomass fuels include: charcoal for households; firewood for households, small restaurants, bakeries and craft centres; agricultural and forest residues for the production of steam and/or electricity in some agro-industrial companies and sawmills.

Figure 1. **Annual Electricity Generation by Source in Côte d'Ivoire in 2019 (GWh)**

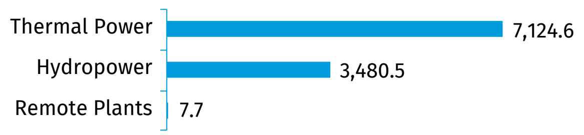
Source: CIE[8]

In 2019, the total electricity generated from all sources was 10,612.8 GWh. This comprised 7,124.6 GWh from thermal power plants, 3,480.5 GWh generated from hydropower and 7.7 GWh from remote plants (Figure 1). Electricity sales to countries in the region amounted to 1,179 GWh, while energy purchases were estimated at 17 GWh.[8]

Electricity generation in Côte d'Ivoire is from two main sources: hydropower contributing 879 MW of installed capacity (approximately 39.4 per cent) and thermal power plants contributing 1,350 MW (approximately 60.6 per cent) (Figure 2). The three following Independent Power Producers (IPPs) own 1,220 MW, or more than 92 per cent, of the total thermal power plant capacity: CIPREL (569 MW), Azito Energie (441 MW) and Aggreko (210 MW). There are also remote plants with generators running on diesel that supply some localities via mini-grids.[8] Their number decreased from 44 in 2018 to 40 in 2019 due to the connection of four localities to the interconnected grid. The installed capacity of these generators is 5,566 kVA or approximately 4.55 MW.

Since the end of 2017, the installed and available capacity supplying the interconnected electricity grid has been 2,229 MW. By March 2021, the installed capacity had not changed since the *World Small Hydropower Development Report (WSHPDR) 2019* in part due to projects being delayed due to COVID-19. The latest power plant in the country was commissioned on 2 November 2017. However, several electricity production units are scheduled for commissioning, including: the 37.5 MW solar photovoltaics (PV) project in Boundiali, which is scheduled to be commissioned in December 2021; the Azito thermal power plant (Phase 4) with combined cycle of 253 MW, the full commissioning of which is scheduled for April 2022; the GRIBOPOPOLI hydropower project of 112 MW, the commissioning of which is scheduled for the second quarter of 2023; and the SINGROBO-AHOUATY hydropower project of 44 MW and the associated energy evacuation network whose commissioning is scheduled for the first quarter of 2023.

Figure 2. **Installed Electricity Capacity by Source in Côte d'Ivoire in 2021 (MW)**



Source: CIE[8]

Out of a total of 8,518, the number of localities electrified in 2019 was 5,859 against 4,940 in 2018. This represented a coverage rate (ratio of the number of electrified localities to the total number of localities) of approximately 69 per cent in 2019 compared to 58 per cent in 2018. In terms of electricity access, the rate of the population living in an electrified area was approximately 94 per cent at the end of 2019 compared to 89.5 per cent in 2018.[9]

Regarding the distribution of electricity, there are two voltage levels for electricity subscribers: the low voltage is intended for households and the medium voltage is intended for companies or factories. The number of subscribers to the low-voltage electrical service increased by approximately 16 per cent between December 2018 and December 2019 from 2,191,290 to 2,532,418. Based on these data, it is estimated that the share of households with access to electricity was 49 per cent in 2019 compared to 44 per cent in 2018.[8] Information regarding rural electrification is not officially available due to the arbitrary nature of rural/urban distinctions in the country.

To accelerate the pace of improvement of the living conditions of the populations, the Government launched, following the instructions of His Excellency Mr. Alassane Ouattara, President of the Republic, the Government Social Programme (PSGouv) for the period 2019-2020. This programme was an intensifier of state social action and targeted all sectors.[10] Regarding access to electricity, the key outcomes of the programme were the reduction in the social tariff for the most disadvantaged households, improved rural electrification and connection/subscription at a lower cost. Thus, the main objectives of the PSGouv in terms of access to electricity were as follows: 1) the downward adjustment of 20 per cent of the nominal social tariff for the customers subscribing to the "social domestic" regime, in order to benefit from a reduction in the cost of electricity; 2) electrification of all of the 1,838 localities with more than 500 inhabitants by 2020 as part of the National Rural Electrification Programme (PRONER), with a target of 917 localities in 2019 and 921 in 2020; 3) facilitation of the connection/subscription to the national electricity grid of 400,000 households eligible for the Electricity For All Programme (PEPT) by the end of 2020, i.e. access to electricity for a population estimated at 2.4 million inhabitants.[9]

Under the technical supervision of the Ministry of Petroleum, Energy and Renewable Energy and the financial supervision of the Ministry for Economy and Finance, several public and private organizations are responsible for various activities in the electricity sector, including the General Directorate of Energy, which defines and implements the national energy policy. Two state companies are involved in the electricity sector: the Society of Energies of Côte d'Ivoire (CI-ENERGIES) and the National Electricity Sector Regulatory Authority (ANARE-CI). CI-ENERGIES is responsible for the planning and implementation of investment projects, while ANARE-CI plays the role of the electricity sector regulator. ANARE-CI was created by decree No. 2016-785 of 12 October 2016 and is vested with more extensive powers of decision, injunction, investigation and sanction to allow better regulation of the electricity sector.[11] As such, the missions assigned to it are in particular: to monitor compliance with laws and regulations as well as obligations resulting from authorizations or agreements in force in the electricity sector; to preserve the interests of users of the public electricity service and to protect their rights; to propose applicable tariffs to the Government in the electricity sector, including network access tariffs; to settle disputes in the electricity sector, in particular between operators and users; and to advise and assist the Government in the regulation of the electricity sector.

The Ivorian Electricity Company (CIE), established in 1990, is a private company responsible for the generation, transmission, distribution, export, import and management of electricity. It is linked to the state by a concession agreement for the public service of electricity for a period of 15 years, which was renewed in 2005 until 2020.[11] Three private operators (CIPREL, Azito Energie and Aggreko) are also involved in the sector as IPPs. They operate thermal power plants fuelled by natural gas supplied by PETROCI–C11, Foxtrot International and CNR International through contracts of sale and purchase signed with the Government.

The strengthening of electricity transmission and distribution infrastructure enabled the sector to have in 2019 an electrical grid with a total length of 54,017 km comprising: low-voltage lines measuring 22,523 km, medium-voltage (15 kV and 33 kV) lines measuring 25,432 km and high-voltage (90 kV and 225 kV) lines measuring 6,062 km.[8]

The Government has adopted a Strategic Development Plan 2011–2030, which covers the development of all sectors including the electricity sector. Within this framework, several projects have been planned concerning electricity generation, transmission and distribution infrastructure.

The electricity base tariffs are fixed by the Government upon the proposal of the regulator. Tariffs are the same for the entire country regardless of the region (Table 1).[12]

Table 1. **Electricity Tariffs under the Post-Payment Scheme in Côte d'Ivoire in 2019**

Tariff base	*Cost excluding 18 % VAT (CFA franc/kWh (USD/kWh)*
Social household low-voltage price (consumption ≤ 80 kWh in a two-month period)*	28.84 (0.057)
Social household low-voltage price (consumption > 80 kWh in a two-month period)	50.16 (0.100)
General household low-voltage price (consumption ≤ 180 kWh/kVA in a two-month period)	66.96 (0.133)
General household low-voltage price (consumption > 180 kWh/kVA by two-month period)	58.04 (0.116)
General professional low-voltage price (≤ 180 kWh/kVA)	86.31 (0.172)
General professional low-voltage price (> 180 kWh/kVA)	73.40 (0.148)

Source: ANARE-CI[11]

Note: *Exempt from VAT

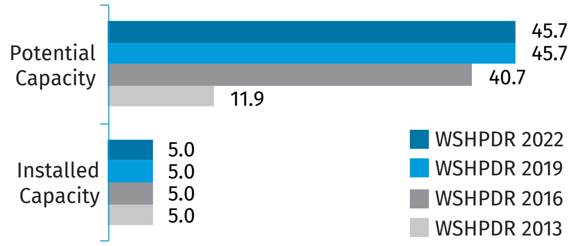
In addition to these base tariffs, there are additional taxes such as a fixed fee for a two-month period, a fee for rural electrification, the Ivorian Radio Television fee and local taxes that vary according to the electricity subscription and the region. Article 2 of Inter-ministerial Order No. 002 of 2 January 2019 stipulates that tariffs shall be revised upwards by 31 March of each year for application on July 1 of that year.[11]

SMALL HYDROPOWER SECTOR OVERVIEW

The official definition of small hydropower (SHP) is less than 10 MW as adopted by the General Directorate of Energy. The country's 5 MW of SHP installed capacity has remained unchanged since the *WSHPDR 2013*; however, estimated potential has increased by approximately 280 per cent, though remained unchanged since the *WSHPDR 2019* (Figure 3, Table 2).

There exists a single SHP plant Côte d'Ivoire, Grah/Faye, which was built in 1983.[13] Since 2018, the plant has been shut down and currently is in need of refurbishment. Thus, there was no available SHP capacity in the country as of Q1 2021.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Côte d'Ivoire (MW)**



Source: SIEREM,[13] *WSHPDR 2013*,[14] *WSHPDR 2016*,[15] *WSHPDR 2019*,[16] CIE[17]

Table 2. **List of Operational Small Hydropower Plants in Côte d'Ivoire**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Grah/Faye	35 km north of the town of San Pedro	5	10	Reservoir	CIE	1983

Source: SIEREM[13]

No SHP projects are currently underway. However, some preliminary studies are expected to be carried out, in particular those planned within the framework of the ENERGOS 2 project, which were delayed due to COVID-19.

Studies conducted in previous years have identified the most promising hydropower development projects. Table 3 consolidates data on sites with an estimated capacity less than 10 MW.[18,19] Based on these studies, dating back to 1979 (and to date the only studies), the total potential capacity for SHP is estimated at 45.7 MW suggesting that less than 11 per cent of the country's SHP potential has been developed. So far, these are the only studies conducted on SHP potential in the country.

Several large hydropower sites have been identified for a progressive development between 2017 and 2025: Soubré (275 MW), Singrobo (44 MW), Gribo-Popoli (112 MW), Boutoubré (156 MW), Louga (280 MW), Daboitié (91 MW), Tiboto (180 MW).[20] For hydropower of all sizes there is a total potential of 1.85 GW on the four major river basins, two times the current hydropower installed capacity.[11] The Soubré hydropower plant (275 MW) has been built and was officially put into service in November 2017. Regarding the Gribo-popoli (112 MW) and Singrobo (44 MW) hydropower plants, the Government has already signed concession agreements for their development.

Table 3. **Small Hydropower Sites Available for Renovation or Development in Côte d'Ivoire**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/ refurbishment)*
Grah/Faye	35 km north of the town of San Pedro	5.00	10.0	Refurbishment
Bandama	Haut Bandama	7.44	20.0	New
Lokpoho	Ferkessedou-gou	7.32	11.0	New
Bia	Aboisso	6.40	5.6	New
Lafigué	Korhogo	4.00	8.0	New
Comoé	Téhini	4.00	10.0	New
La palé	Boundiali	3.50	30.0	New
Drou	Man	2.56	162.0	New
Agnéby	Laouguié	2.01	21.0	New
N'zi	Fétékro	1.60	23.0	New
Banoroni	Séguéla	1.50	18.0	New
Sassandra	Daloa	0.17	2.8	New
Agnéby	Kassiguié	0.16	3.6	New

Source: CI-ENERGIES,[18] EDF[19]

RENEWABLE ENERGY POLICY

During the period 2013–2030, as part of the Strategic Development Plan 2011–2030, the Government aims to increase the share of renewable energy in the country's energy mix. In addition, Côte d'Ivoire committed itself to the Paris Agreement to reduce its greenhouse gas emissions. This commitment is reflected at the level of the electricity sector, by increasing the share of renewable energy in the energy mix to 42 per cent (including large hydropower) by 2030. This renewable energy policy will support the following renewable sources: biomass, hydropower, solar power and, possibly, wind power.

Several projects for electricity generation from renewable energy sources are planned, including: a solar power project of 25 MW in Korhogo; a Canadian solar power project (Galilea) of 50 MW in Korhogo; a solar PV project of 25 MW in Odienné; a solar power project of 25 MW developed by Bio-Therm Energy in Ferkéssedougou; a cocoa biomass power plant of 25 MW in Gagnoa; and a cotton biomass power plant of 20 MW in Boundiali.[21,18,22]

At the end of 2019, the country adopted a Sector Policy Document for the Development of Renewable Energies and Energy Efficiency (PSDEREE) with the vision of making Côte d'Ivoire a leading country in the field of renewable energy, optimal use of energy in all its forms, in order to contribute to the country's energy security and the protection of the environment in 2030.[23] This document has set the objectives of Côte d'Ivoire in terms of renewable energy and energy efficiency for the period 2020-2030. The specific objectives in terms of renewable energy are as follows:

- To promote the development of green electricity production infrastructure connected to the interconnected grid so as to increase the share of renewable energy in the electricity mix to 42 per cent in 2030, including large hydropower;
- To promote the development of green electricity production infrastructure not connected to the interconnected grid in order to accelerate the electrification of camps and isolated sites;
- To increase access to electricity for rural populations through off-grid electrification and to promote renewable energy for other uses, in particular domestic and commercial applications;
- To increase the production and use of fuels from renewable sources other than wood (briquettes, biogas, biofuels, etc.) as well as to promote modern technologies for charcoal production;
- To increase the use by households, hotels, health centres and school canteens of modern cooking systems and solar water heaters;
- To increase access to energy services for farmers through the use of renewable energy in production systems, including irrigation (solar pumping), units for processing and preserving agricultural products, pasteurization, fish farming, etc.;
- To reduce greenhouse gas emissions through the promotion of renewable energy.

There is no specific legislation or regulation for SHP. Data on costs of SHP development are not available. In addition, no financial mechanism is put in place for the development of SHP projects.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Increased variability in rainfall and shifting rainy seasons will require attention if the SHP sector is to adapt to climate change in the future. Rising temperatures are also of concern, and consequences for the sector due to temperature change should be a topic of further attention.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are multiple barriers to SHP development in Côte d'Ivoire. Some of the most significant ones are outlined below:

- The lack of new studies on potential sites; new studies could confirm a potential significantly greater than the current estimation of 40.685 MW;
- The main focus is on larger hydropower projects rather than on plants with capacity of up to 10 MW;
- Limited data available in the sector and restriction of information might considerably deter foreign investment.

However, due to the importance of the electricity sector for the country's economic recovery, more attention is being paid to the potential of renewable energy and it is likely that SHP will also benefit from this.[11]

The following points summarize the main enablers that have been identified:

- The political will to accelerate the transition to renewable energy sources including SHP in order to improve the electricity mix, which is predominantly fossil-based (natural gas) at the moment;
- The political will to electrify all the localities of the country by 2025. Although the preferred option is the connection by extension of the electricity grid, the development of local potentials so as to allow a better penetration of renewable sources including SHP, is recommended;
- The country is currently benefiting from technical assistance from the European Union to carry out the necessary studies to enable the development of the potential of renewable energy sources, including SHP.

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Republic of the Gambia

Annabel Johnstone, Kaboni

KEY FACTS

Population	2,347,706 (2020)[1]
Area	11,300 km^2 [2]
Topography	The topography of Gambia is flat and largely defined by the drainage basin of the Gambia River. The highest point is in the east of the country, at Red Rock, at 53 metres above sea level. The land elevation gradually decreases from the east to the west, with the capital city of Banjul situated below 5 metres above sea level at the mouth of the Gambia River. Shallow valleys characterize the banks of the Gambia River, which cuts through the plateau across the country.[3,4]
Climate	Gambia has a wet-and-dry tropical climate characterized by an intense rainy season occurring generally between June and October, followed by a longer dry season. The east of the country experiences a hotter and drier climate (temperatures in the high 20s °C), with the climate becoming cooler and drier in the west by the coast (temperatures in the low 20s °C). The relative humidity is high but drops from December to April, when the dry north-eastern wind known as the Harmattan is dominant.[5]
Climate Change	Gambia is highly vulnerable to rainfall variations caused by climate change, which disrupt the agricultural workers' (44 per cent of the population) traditional knowledge of the historic patterns of rainfall and optimal harvest times. Climate change impacts, such as increasing temperatures, droughts, a shifting rainy season with decreased intensity as well as increased deforestation, have resulted in half the available land in Gambia becoming degraded through topsoil and secondary sediment erosion. According to the Climate Change Knowledge Portal, mean annual temperatures are expected to rise by between 1.1 and 3.1 °C by 2060, and between 1.8 and 5 °C by 2090 .[6,7,8]
Rain Pattern	The rainy season lasts longer and is heavier by the coast, while rainfall intensity diminishes eastwards. At the town of Yundum (west), the average annual rainfall averages 1,300 mm, while at the town of Basse Santa Su, approximately 435 km inland, it averages 1,000 mm. August is the rainiest month, when rainfall exceeds 300 mm in the city of Banjul.[4,5]
Hydrology	Gambia is dominated by the Gambia River, a major river of Western Africa. The river, 470 km long, and its tributaries occupy 970 km^2 of permanent surface water area. Total renewable water resource in Gambia is constant at 8x10^9 m^3 per year, of which approximately 62 per cent flows into Gambia from neighbouring countries. The total head of the Gambia River in Gambia is 10 metres. A combination of increased temperatures and reduced rainfall from climate change is expected to decrease annual streamflow by 22 per cent by 2050, according to a global warming scenario of 3.5 °C by the year 2100.[9,10]

ELECTRICITY SECTOR OVERVIEW

The electricity sector in Gambia is predominantly non-renewable, with only 3 MW of the 105 MW of installed capacity as of 2019 coming from renewable sources (2 MW of solar power and 1 MW of wind power) (Figure 1). Similarly, most new capacity added over the last decade comes from non-renewable sources: 11 MW from non-renewable sources compared to 2 MW from solar power.[11]

Gambia does not import or export electricity. However, projects from the World Bank, United Nations Environment Programme (UNEP) and the Economic Community of West African States (ECOWAS) have proposed the development of the Soma hydropower plant in neighbouring Senegal as a shared project, which would represent a supply increase for Gambia to approximately 250 MW.[12,13]

Figure 1. **Installed Electricity Capacity by Source in Gambia in 2019 (MW)**

Source: IRENA[11]

Total electricity generation reached 342.6 GWh in 2019, 336.1 GWh of which came from fossil fuel sources, with only 6.5 GWh of electricity generated from solar power and no recorded wind generation (Figure 2).[14]

Figure 2. **Annual Electricity Generation by Source in Gambia in 2019 (GWh)**

Source: Africa Energy Portal[14]

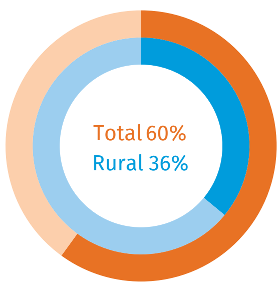
Until 2007, the country's electricity sector was controlled by the National Water and Electric Company (NAWEC), a vertically integrated monopoly under the supervision of the Ministry of Petroleum and Energy. In 2007, the Global Electric Group (GEG) was contracted by NAWEC to build, own, operate and maintain one of the two heavy fuel oil power generation facilities in the greater Banjul area in Brikama Kabafita, known as the Brikama power plant. This nearly doubled the available capacity in the country from approximately 31 MW to 55 MW. The GEG now jointly handles operations with NAWEC. Although this agreement set the precedent for the use of the independent power producer (IPP) structure in Gambia, no new electricity generation capacity has been added since, despite interest from other potential IPPs. Organisations responsible for encouraging investment in the country are the Renewable Energy Association of the Gambia (REAGAM) and the Gambia Investment and Export Promotion Agency (GIEPA).[15]

Special attention can be paid to REAGAM, a non-profit cooperation of approximately 17–19 private and public companies and individuals active in the promotion of renewable energy projects in the country, such as small solar photovoltaic (PV) installations, solar thermal power and micro-hydropower.

Despite the current low share of renewable sources in its energy mix, Gambia has a target to achieve a 100 per cent renewable energy mix by 2050, with 20 per cent of electricity coming from renewable sources by 2030. [11]

In 2018, 60 per cent of the total population had access to electricity, including 76 per cent of urban residents and 36 per cent of rural residents (Figure 3).[14]

Figure 3. **Electrification Rates in Gambia in 2018 (%)**



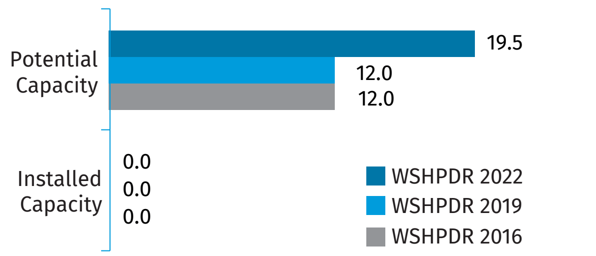
Source: Africa Energy Portal[14]

The regulation of electricity tariffs is the key role of the Public Utilities Regulatory Authority (PURA), alongside monitoring and enforcing standards of performance by public utilities and protecting the interests of the consumers. Electricity tariffs are regulated at 0.26 USD/kWh for the highest domestic consumption band and remain vulnerable to oil prices and foreign exchange shocks.[15] A lifeline tariff is offered for low-income households for the first 40 kWh consumed at a subsidized rate of 0.07 USD/kWh.[15]

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) is defined as hydropower plants with a capacity of up to 30 MW. For the purposes of this chapter, SHP will refer to hydropower plants with an installed capacity of up to 10 MW. Compared to the World Small Hydropower Development Report (WSHPDR) 2019, the SHP sector of Gambia has not seen any development. The estimate of technical potential for SHP up to 10 MW increased by 7.5 MW, to 19.5 MW, due to access to more accurate data (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2016/2019/2022 in Gambia (MW)**



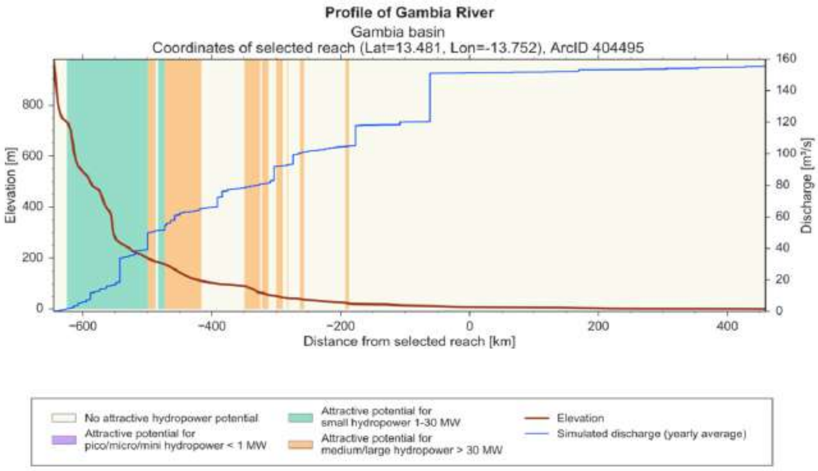
Source: *WSHPDR 2016*,[16] *WSHPDR 2019*,[17] Korkovelos et al. 2018[18]

Note: Data for SHP up to 10 MW.

There are currently no active or planned hydropower plants in Gambia, although there is a planned Western African project under ECOWAS supervision with implications for Gambia. The project envisions that two new hydropower plants located in close proximity to one another will be connected to a new regional network. The plant at Kaléta (240 MW) along with the Souapiti hydropower plant (450 MW) in Guinea will be connected to the mining region of Boké, Sénégal, Guinea Bissau and Gambia through the OMVG (the Gambia River Development Organization) line and to Côte d'Ivoire, Liberia and Sierra Leone through the CLSG (Côte d'Ivoire, Liberia, Sierra Leone and Guinea) line. The Sambangalou plant (128 MW) in Senegal will further connect to the capital of Gambia, Banjul.[19,20]

The lack of activity in SHP development in Gambia can be explained by the limited hydropower potential. In 2017, Pöyry in conjunction with ECOWAS and the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) undertook a project of mapping SHP development potential in 14 Western-African countries.[21] The report found that Gambia was well suited for SHP development, with the theoretical

Figure 5. **The Level of Attractiveness of Small Hydropower in Gambia by Elevation (m) and Discharge (m³/s)**



Source: ECREEE[14]

hydropower potential for the Gambia River estimated at 10 MW (reference period 1998–2014), whereas the estimated potential of other small streams is negligible. Therefore, all of the identified potential hydropower sites in Gambia are suitable for SHP development.[22]

The attractiveness of any hydropower projects on the Gambia River drops off at the elevation of 25 metres (Figure 5) and as mentioned previously, the entire hydrology system in Gambia has a maximum head of only 10 metres.[14]
A separate study conducted in 2018 found only one potential mini-hydropower site (0.1–1 MW) with 0.5 MW of potential capacity and three potential SHP sites (1.01–10 MW) totalling 19 MW. However, the locations of these sites are unknown.[20] Therefore, the known technical potential of SHP in Gambia is 19.5 MW, coming from four sites.

RENEWABLE ENERGY POLICY

The passing of the Renewable Energy Act in 2013 was a major step forward for Gambia in terms of the promotion of renewable energy. The Act defines a number of functions for the Ministry of Energy, including:

- Recommending national renewable energy targets;
- Determining equipment eligible for tax exemption;
- Preparing and co-ordinating the permitting process for facilities using renewable energy sources;
- Promoting the implementation of educational programmes within the renewable energy sector;
- Encouraging the development of technical and standard requirements and certification of renewable energy plants; and
- Establishing and managing a registry to monitor renewable energy facilities.[23]

The Act also defines a number of functions for PURA, including:

- Managing the Renewable Energy Fund;
- Maintaining a register of installers of systems using renewable energy resources; and
- Requiring importers of systems using renewable energy resources to provide details of compliance with internationally recognized performance and safety standards.

The Act establishes the Renewable Energy Fund and defines its funding sources, activities to be funded and management structure. The Act allows for feed-in tariffs (FITs) for on-grid renewable electricity projects with a capacity up to 1.5 MW. The maximum national capacity limit for electricity production eligible under the Act is to be published in the Feed-in Tariff Rules. The Act also provides clarification about off-grid tariffs. Renewable energy or hybrid off-grid plants of no greater than 200 kW are allowed to charge electricity tariffs to end consumers up to the current national retail tariff rates. For systems of greater than 200 kW and if the power plant developer wants to charge above the national retail tariff rate, developers must justify the tariff to the PURA as per the Electricity Act.[26]

However, certain gaps exist in the Act, which, if addressed, would provide key information for potential renewable energy development. These gaps consist of, but are not limited to:

- Provision of FITs for on-grid renewable energy plants of more than 1.5 MW;
- Provision of tariffs for off-grid renewable energy plants of more than 200 kW;
- Technical and standard requirements and certification of renewable energy plants.

There is no specific mention of SHP in the Renewable Energy Act, apart from as part of hybrid power plants. As such, the process for SHP projects should not be determined as different to the licence pathways for other renewable generation projects, which was streamlined under the Act. Instead, the Act specifically mentions biomass as a main strategy towards electrification.

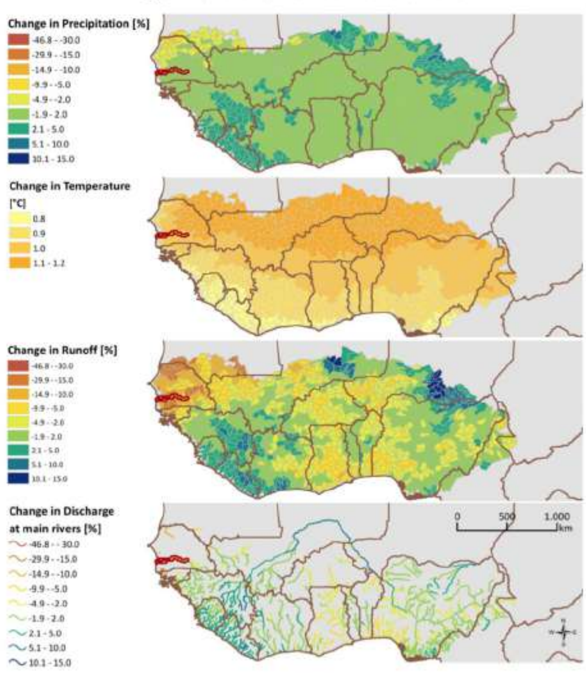
FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Grid-connected SHP would be eligible for partial financing in the Nationally Appropriate Mitigation Action (NAMA) report of the Renewable Energy Fund set up in 2013, as well as VAT exemptions on electricity produced. There are also opportunities to attain grant financing from ECOWAS, though the pathways are unclear. The World Bank has an ongoing project to restore and modernize the electricity system in Gambia, though references in the concept note to hydropower are uncommon and more emphasis is put on solar power projects for off-grid and rural electrification.[25] The project was approved in 2018 and received additional financing in 2020.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change may have considerable impact on future water resources and therefore hydropower generation. Figure 6 shows an assessment of climate change projections for Western Africa based on 15 regional climate models of the CORDEX-Africa ensembles. Two Representative Concentration Pathways (RCP4.5 and RCP8.5) were considered.[22] Whilst these changes have direct impacts on technical specifications of SHP, they will also have indirect impacts on the national tariff, reduction in agricultural revenue and an increase in flooding emergency if no immediate mitigation measures are taken.

Figure 7. **Change in Precipitation, Temperature, Runoff and Discharge in Western Africa under RCP4.5 and RCP8.5**



Source: ECREEE[21]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The electricity sector of Gambia is characterized by a number of enablers which provide opportunities for the realization of the goal of universal access to electricity. The strengths of the power sector, which could foster SHP development include the following:

- The Government's strong commitment to expand the electricity network to many communities in the country;
- Willingness of the private sector (investors) to partner with the Government to provide electricity services;
- Examples of connectivity within the subregion to learn from;
- Availability of financing through the FIT scheme;
- Available information on potential SHP sites for future development;
- Presence of a market (domestic and commercial) for the electricity that could be produced in future.

The electricity sector also faces several challenges in achieving the stated goal of ensuring wider access to electricity in Gambia, which complicates SHP development in the country. The sector barriers include the following:

- Inadequacy of the transmission and distribution network, creating incompatibility for large-scale public-private partnerships;
- Operational inefficiencies in the key utility company NAWEC resulting in transmission and distribution losses;
- NAWEC's poor financial performance;
- Weak regulatory and enforcement capacity;
- High electricity tariffs and non-affordability of electricity;
- Limited SHP potential in the country.[15,26]

These challenges combined with the low availability of commercially attractive sites will make any new development of SHP in Gambia challenging. The most viable area to focus on with SHP is the Gambia River and its estuaries in the centre of the country, near the village of Tendaba.

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Ghana

Chinedum Ibegbulam, Renewable Energy and Development Practitioner

KEY FACTS

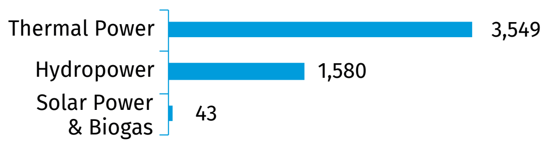
Population	31,498,920 (2022)[1]
Area	238,540 km^2 [2]
Topography	The physical terrain of Ghana is primarily represented by low plains, with several uplands and a major plateau in the south-central region. The country's highest point is Mount Afadjato at 885 metres above sea level.[3]
Climate	Ghana is characterized by a tropical climate that is relatively mild for the latitude. With the exception of the north, two rainy seasons exist, which run from April to June and from September to November. There is also a harmattan season, which is characterized by dry wind blowing from the north-east from December to March. Average temperatures range between 21 °C and 32 °C. In most areas, temperatures are highest in March and lowest in August, but no temperature lower than 10 °C has ever been recorded in Ghana.[4]
Climate Change	Over the 1961–2000 observation period, a progressive rise in temperatures and a decrease in mean annual rainfall have been recorded across the country. Other observed effects of climate change include increased variability of precipitation, rising sea levels and high incidence of extreme weather conditions and disasters. In the last 30 years, the average annual temperature increased 1°C and is projected to continue to rise. Similarly, rainfall is predicted to continue to decrease.[5]
Rain Pattern	There is a significant variation of rainfall pattern throughout the country. In the south, annual precipitation averages 2,030 mm, while Axim in the south-west of the country has the heaviest rainfall. Averagely, the month of June is the wettest month with rainfall of approximately 225–250 mm.[6]
Hydrology	Most rivers and streams north of the Akuapim-Togo ranges, including Black Volta and White Volta, form part of the Volta River system. The Volta River is approximately 1,600 kilometres in length and drains an area of approximately 388,000 km^2. The Black Volta and White Volta meet at Lake Volta, which was formed as a result of the construction of the Akosombo dam. It is also the world's largest man-made lake. There are also several other smaller rivers such as Pra, Tano, Densu, Birim and Densu.[6]

ELECTRICITY SECTOR OVERVIEW

In 2019, Ghana had a total installed generation capacity of 5,172 MW (4,695 MW of available capacity), which comprised 3,549 MW (3,296 MW available) from thermal power plants, 1,580 MW (1,365 MW available) from hydropower plants and 42.6 MW (34 MW available) from solar power and biogas combined (Figure 1).[7] The electricity generation mix in Ghana has primarily relied on hydropower and thermal power sources, however, steps have been made to introduce other renewable energy technologies in order to diversify the mix. In 2019, solar power and biogas accounted for 0.8 per cent of total installed capacity, indicating an increase compared to 0.2 per cent in 2016.[8]

Electricity generation in 2019 totalled 18,189 GWh, with thermal plants contributing almost 60 per cent (10,885 GWh), hydropower plants 40 per cent (7,252 GWh) and solar power and biogas combined 0.3 per cent (52 GWh) (Figure 2).[7] An additional 127 GWh was imported into Ghana in 2019 and 1,430 GWh was exported, making the net export 1,227 GWh.[7] Ghana imports electricity from Côte d'Ivoire and exports electricity to other neighbouring countries, including Benin, Togo and Burkina Faso. The ongoing grid expansion will allow for further expansion to other neighbouring Sub-Saharan African countries.

Figure 1. **Installed Electricity Capacity by Source in Ghana in 2019 (MW)**



Source: Energy Commission[7]

Figure 2. **Annual Electricity Generation by Source in Ghana in 2019 (GWh)**

Source: Energy Commission[7]

The National Electrification Scheme (NES) served as the principal instrument towards providing universal access in Ghana over a 30-year period (from 1990 to 2020). Since 1990, there has been a trend of annual increase in electrification access rate of 2.6 per cent.[9] However, the set electrification target was not achieved and in 2020 the national electrification rate stood at 86 per cent, including 95 per cent in urban areas and 74 per cent in rural areas.[10]

Before the late 1990s, the electricity sector of Ghana was a vertically integrated monopoly, with the Volta River Authority (VRA) responsible for generating and transmitting electricity to every region of the country as well as its distribution in the Northern Region through its subsidiary the Northern Energy Department (NED). The electricity sector reform in the late 1990s split the VRA and provided an opportunity for independent power producers (IPP) to enter the market. Electricity generated from hydropower is controlled by the VRA and Bui Power Authority (BPA). Additionally, the VRA and IPPs are also involved in some aspects of thermal power generation. Transmission is solely controlled by Ghana Grid Company (GRIDCO), while distribution is controlled by the state-owned entities the Electricity Company of Ghana (ECG) and the Northern Electricity Distribution Company (NEDCO).[11]

The Ministry of Energy is in charge of the formation, monitoring and evaluation of polices, programmes and projects for the country's electricity sector and is also responsible for the implementation of the NES. There are two regulatory entities responsible for the electricity sector in Ghana. The Energy Commission (EC) is responsible for issuing generation licences and for formulating electricity policy and rules governing the electricity sector including a grid code. The Public Utilities Regulatory Commission (PURC) is responsible for the regulation of the electricity, gas and water sectors, which includes tariff setting.[9]

The regional stakeholders, such as the West African Power Pool (WAPP), the ECOWAS Regional Electricity Regulatory Authority (ERERA) and ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE), play an important role in the improvement of energy security in the country through interstate electricity trade and supporting improved energy services. International agencies providing support to the electricity sector of Ghana, ranging from technical assistance to financing power infrastructure projects, include the World Bank Group, African Development Bank (AfDB), United States Agency for International Development (USAID), Canadian International Development Agency (CIDA), International Renewable Energy Agency (IRENA), United Nations Environment Programme (UNEP) and Global Environment Facility (GEF).[9]

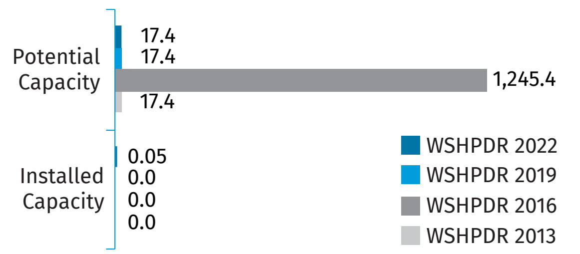
In order to sustain the real value, electricity tariffs in Ghana are adjusting based on a number of factors, such as fuel price, foreign exchange, inflation and generation mix. For low-income consumers with low consumption, PURC instituted the lifeline tariff below the cost of electricity provision.[9] Electricity tariffs are grouped into six categories based on consumer category (residential, non-residential, special load tariff and mines) and voltage level. As of January 2021, the price per kWh of electricity for residential consumers ranged from 0.33 GHS (0.04 USD) to 0.94 GHS (0.12 USD), with a monthly service charge of 7.46 GHS (0.95 USD/month) for regular consumers.[12]

SMALL HYDROPOWER SECTOR OVERVIEW

In Ghana, small hydropower (SHP) is defined as hydropower plants with capacity of up to 1 MW. Additionally, medium-scale hydropower is defined as plants with 1–10 MW capacity and large-scale hydropower as plants with 10–100 MW capacity.[13]

At present, there is one installed SHP plant in Ghana, which is the Tsatsadu power plant located in Alavanyo, Volta region. The plant was launched in 2020 and has an installed capacity of 45 kW (Table 1).[14] The SHP potential up to 10 MW is estimated to be at least 17.42 MW and approximately 9.9 MW for SHP up to 1 MW.[13] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity increased due to the commissioning of a new plant and potential remained unchanged (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Ghana (MW)**



Source: ECREEE,[13] Bui Power,[14] *WSHPDR 2013*,[15] *WSHPDR 2016*,[16] *WSHPDR 2019*[17]

Note: Data for SHP up to 10 MW.

Table 1. **List of Existing Small Hydropower Plants in Ghana**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Tsatsadu	Alavanyo, Volta region	0.045	Run-of-river	Bui Power Authority (BPA)	2020

Source: Bui Power[14]

According to a 2012 report, the hydropower potential capacity in Ghana is 2,420 MW.[13] Various studies provide different estimates of SHP potential in different regions of the country. The Hydrological Service Department of the Ministry of Works and Housing identified approximately 15.18 MW of SHP potential from 69 sites below 2 MW. Additionally, reports by the Energy Foundation suggest that there is a potential for 2.24 MW from 12 sites less than 1 MW. Therefore, it can be assumed that the total SHP potential up to 10 MW in Ghana is at least 17.42 MW.[13] Table 2 shows a list of selected most interesting potential SHP sites identified using topographic sheets and flow data from several rivers.

Table 2. **List of Selected Potential Small Hydropower Sites in Ghana**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Type of site (new/refurbished)*
Wli Falls	Afegame, Volta region	0.30	250	Run-of-river	New
Likpe Kukurantumi	Likpe Kukurantumi, Volta region	0.10–0.15	Up to 5 m by dam	Reservoir	Refurbished (construction went on for 11 months before work stopped)
Kokuma Falls	Kokuma, Brong-Ahafo	0.05	23	Run-of-river	New
Randall Falls	Kintampo, Brong-Ahafo	0.08	40	Run-of-river	New
Nworannae Falls	Asmpanaye, Western region	0.04	50–100	Run-of-river	New

Source: ECREEE[13]

RENEWABLE ENERGY POLICY

Ghana heavily depends on hydropower, mainly from the Akosombo dam, as a source for electricity generation, because hydropower provides the cheapest source of electricity compared to thermal power and other renewable energy sources. Nonetheless, the potential for alternative sources of electricity exists in the country, which includes medium-sized hydropower, mini-hydropower and other renewable energy sources, such as solar and wind power.

In 2011, the Renewable Energy Act (Act 832) was passed in order to provide a legal framework for renewable energy development.[18] The key provisions of the act included a feed-in tariff (FIT) scheme, purchase obligation and net metering. As a result, EC together with PURC developed a FIT to incentivize investment in the sector. PURC is mandated to set the FIT rates, based on which developers would be able to sign power purchase agreements (PPAs) with the distribution companies following a written approval from PURC. The Renewable Energy Act also provides for the establishment of a Renewable Energy Fund, which provides financial resources for renewable energy projects.

The Renewable Energy Master Plan (REMP) developed in 2019 offered a roadmap for long-term development of renewable energy in the country until 2030. The REMP set the following targets to be achieved:

- Increase the installed capacity of renewable energy (including hydropower up to 100 MW) to 1,363.63 MW;
- Reduce dependence on biomass;
- Provide decentralized renewable energy-based electrification options in 1,000 off-grid communities;
- Promote local content and participation in the renewable energy industry.[19]

The REMP also prescribed action plans for all renewable energy technologies. For hydropower (small- and medium-scale), the 2030 installed capacity target is set at 150 MW. According to the REMP, the Government aims to develop multiple SHP plants. The Tsatsadu plant was the first project developed under the plan. The key strategies for promoting hydropower include:

- Fast track and deploy innovative financing instruments;
- Develop a clear framework and legislation for small- and medium-scale hydropower development;
- Provide incentives, such as state-funded feasibility studies and public-private partnership arrangements;
- Collaborate with relevant stakeholders to create buffer zones, undertake reforestation and prevent mining, farming and logging activities along water ways;
- Encourage hybrid and multipurpose hydropower development (fisheries, transportation, irrigation, etc.);
- Provide capacity building for utilities, local authorities and research institutions in the installation, operation and maintenance of hydropower facilities.[19]

The Volta River Development Act 1961 (Act 46) (the VRA Act) established the oldest power entity in Ghana, the VRA. The VRA Act tasked the VRA with the responsibility to generate electricity by means of hydropower on the Volta River. In 2007, the Parliament enacted the Bui Power Authority Act 2007 (Act 740) (the Bui Power Act), which established the Bui Power Authority to oversee the development of the Bui hydropower project and any other potential hydropower sites on the Black Volta River.[20]

Under the Energy Commission Act 1997 (Act 541), participation in any segment of the electricity sector requires a licence. EC is required to make a decision on any application within a maximum period of 16 days. Reasons for denying licence issue can be founded on technical data, national security concerns, public safety or any other reasonable justification. The VRA is exempted from the requirement to apply for a licence for producing and supplying wholesale electricity from hydropower plants in the Volta River basin. Furthermore, under the Renewable Energy Act, every entity intending to engage in a commercial activity in the renewable energy sector requires a licence. To construct and operate distribution networks, an electricity distribution licence issued by EC is required. An electricity distribution licence is site-specific.[20]

In 1994, the Environmental Protection Agency Act 1994 (Act 490) was enacted in order to ensure that electricity is produced, transmitted and distributed in an environmentally sustainable manner. The act established the Environmental Protection Agency (EPA) as the principal environmental regulator in the country. Before undertaking a project, an electricity utility must receive an environmental permit from the EPA. The EPA ensures compliance with the environmental impact assessment (EIA) procedures.[20]

COST OF SMALL HYDROPOWER DEVELOPMENT

A 150 kW site at Likpe Kukurantumi with an annual output of 500–640 MWh was suggested for development. The construction cost was estimated at USD 300,000, or USD 2,000 per kW installed. The site has a head of 5 metres and, given that low-head sites are relatively more expensive to construct than high-head sites, the actual cost could be higher at approximately 3,500 USD/kW.[21]

FINANCIAL MECHANISM FOR SMALL HYDROPOWER PROJECTS

Existing financial mechanisms available for SHP projects include internally generated revenue, bilateral financing and financing from international and non-governmental organizations as well as foreign governments. The Tsatsadu SHP plant was funded largely by the Government of Ghana through BPA with financial support from the Government of Denmark and the United Nations Development Programme (UNDP).[14] An example of bilateral financing is the 400 MW Bui Dam hydropower project financed through a concessional loan of USD 270 million and a commercial loan of USD 292 million offered by China Ex-Im bank and USD 60 million in funding from the Government of Ghana.[22]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The climate crisis poses risks to SHP development in Ghana primarily through changes in precipitation, including decreased rainfall and increased variability, and higher incidence of extreme weather conditions. A range of tailored adaptation measures based on a systematic assessment of climate risks will be required to ensure sustainable operation of SHP plants, including the physical enhancement of assets and development of appropriate strategies and policies related to, for example, emergency response and recovery.[23]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Barriers to SHP development in Ghana include:

- Lack of a regulatory and legal framework for SHP development;
- Limited funding opportunities;
- Minimal national and regional knowledge and awareness of the potential of SHP;
- Limited local expertise in developing SHP projects;
- Lack of data on water availability and flow for the development of SHP;
- Impacts of climate change on hydropower generation.[17,24]

Nonetheless, further SHP development in Ghana is possible due to the following factors:

- Political will to develop renewable energy and increase electricity access, with specific goals set for hydropower;
- Availability of undeveloped potential, with a number of suitable sites identified;
- Availability of international and regional support for renewable energy development in the country.

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Guinea

Aissatou Billy Sow, Guinean Association for the Promotion of Renewable Energy (AGUIPER), Abou Kawass Camara, Electricité de Guinée (EDG), and Tamsyn Lonsdale-Smith, ICSHP

KEY FACTS

Population	12,907,395 (2021)[1]
Area	245,857 km^2 [1]
Topography	The mid-northern region of Guinea extends from east to west in the form of a maritime plane (Lower Guinea), a region of plateaus and mountains (Middle Guinea) and the arid plateau of Upper Guinea. The south-western tip of the country, in the interior of the continent is a forested mountainous region known as Forested Guinea. It is here that the country's highest point, Mount Nimba (1,752 metres), is located. Middle Guinea surrounds the Fouta Djalon Massif, which covers an area of approximately 80,000 km^2 and culminates at Mount Loura (1,532 metres). It is mainly made up of plateaus, often more than 1,000 metres high, cut by valleys, dominating plains and depressions up to approximately 750 metres. The coastal plain of Lower Guinea is dominated to the east by the Benna Massif (1,214 metres), Mount Kakoulima (1,011 metres) and Mount Gangan (1,117 metres).[2]
Climate	The climate of Guinea is tropical or sub-equatorial depending on the area. The diversity of the terrain divides the territory into four regions with distinct climatic conditions. Lower Guinea has the longest rainy season of six months and temperatures range from 23 °C to 25 °C. Middle Guinea has shorter rainy seasons compared to Lower Guinea. In Upper Guinea, the climate is tropical and dry, with only three months of a rainy season and temperatures reaching at most 40 °C in the north-east and lows reaching 15 °C in the winter months. Forested Guinea has an equatorial climate with two separate rainy seasons interrupted by a short dry period. This region is largely humid with temperatures fluctuating between 24 °C and 28 °C for the most part of the year.[3,4]
Climate Change	According to global circulation models, annual rainfall variability and temperatures are expected to increase in Guinea under all scenarios, with some regional variation. Under a global warming scenario of 4.5 °C, the range of temperature increase in the country is expected to be between 0.4 °C and 4.8 °C by 2100. Under the 1.5 °C global warming scenario, temperatures will increase by 0.2-2.2 °C.[2]
Rain Pattern	Precipitation in the country varies by region. In the north, annual precipitation is approximately 1,200 mm per year, whereas in the south, precipitation levels can reach as high as 4,000 mm per year. Although the average in the south-east is between 1,700 and 3,000 per year. The central mountainous region of Middle Guinea has precipitation levels ranging from 1,500 to 1,300 mm per year, with the rainiest season being from April to October and the dry season from November to March.[4]
Hydrology	Nearly 1,161 water bodies in the country are fed by two mountainous massifs: the Fouta-Djallon and the Guinean Highlands (Dorsale Guinéenne). Most of the rivers have a regular flow because of the high rainfall and the very flat topography of the coastal region. However, in the part of the Lower Guinea region that borders the Fouta Djallon in its foothills, the rivers sometimes have a torrential flow due to the steepness of the slope and the rocky bottom. The most important rivers are: the Coliba, Kogon, Tinguilinta, Fatala, Konkouré, Soumba, Kolenté, and Forécariah. The prominent rivers in Middle Guinea are the Bafing and Gambia. The main rivers in Upper Guinea are the Bafing, Bakoye and the Niger basin, whose main tributaries are Mafou, Niandan, Milo, Tinkisso, Dion, Sankarani and Fié. Together they total approximately 2,500 kilometres of waterways. In addition, there are numerous large ponds and flood plains that run alongside the rivers, covering an average area of 2–4 km^2. In Forested Guinea, the main bodies of water and watercourses are made up of numerous very small ponds of less than 1 hectare in size.[2,5]

ELECTRICITY SECTOR OVERVIEW

Apart from small-scale, off-grid generation, the electricity demand of Guinea is largely met by two sources: hydropower and thermal power. Total installed capacity as of 2019 was 601.9 MW. Hydropower made up most of the installed capacity at 362.1 MW, thermal power accounted for 226.8 MW and solar power accounted for 13 MW (Figure 1).[6,7]

Figure 1. **Installed Electricity Capacity by Source in Guinea in 2019 (MW)**

Source: EDG,[6] IRENA[7]

Note: Data only for the interconnected electricity grid (RIC).

In 2019, electricity generation in Guinea was equal to 2,040.7 GWh, of which 1,279.6 GWh came from hydropower, 21 GWh from solar and 740.1 GWh came from thermal power plants (Figure 2).[7,8] Hydropower made up 63 per cent of the on-grid generation. Of the electricity produced in 2019, the electricity company Electricité de Guinée (EDG) produced 25 per cent (496.1 GWh), while the remaining 1,483.4 GWh was produced by independent power producers (IPPs). The majority of hydropower generation is from the private Kaleta generator, which peaks in production from July to November, making up most of the country's electricity supply during these months.

Figure 2. **Annual Electricity Generation by Source in Guinea in 2019 (GWh)**

Source: EDG,[8] IRENA[7]

Note: Data only for the interconnected electricity grid (RIC).

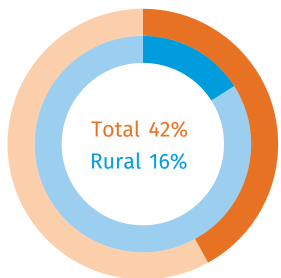
The electricity sector covers 26 urban centres in the prefectures whose electricity networks are managed and operated by EDG. EDG is charged with ensuring the provision and transport of electricity throughout the country and owns 35 per cent of the electricity market, acting as the sole buyer for many electricity producers. The Ministry of Energy (ME) (previously Ministry of Energy and Hydraulics (MEH)) oversees the electricity sector. Its organization and prerogatives were defined by Decree No. D/2016/122/PRG/SGG of 2016. Article 1 of this decree provides that the Ministry's mission is the design, development and implementation of the Government's water and energy policy. A presidential decree in 2005 established the Office of Strategy and Development of Energy (BSD), an organization charged with elaborating a strategy for the development of the energy sector. The Cellule PPP manages the public-private partnerships within the Government and acts as an interface for IPPs in the country. The country's independent power regulator, AREE (Authority for Electricity and Drinking Water Sectors), was created in 2017 by the ordinance L/2017/050/AN.

The main electricity grid, called the large interconnected grid, supplies hydropower and thermal power to Conakry, Dubréka, Coyah, Forécaréah, Kindia, Mamou, Pita, Labé and Fria. The small interconnected grid supplies the prefectures of Dabola, Dinguiraye and Faranah with electricity from the Tinkisso hydropower plant (1.6 MW). There are also the so-called isolated centres (Boffa, Gaoual, Télémelé, Lélouma, Kissidougou, Kouroussa, Boké, Kankan, Kérouané, Macenta and N'Zérékoré), which are supplied with electricity by small-scale generators (often hybrid solar with battery and diesel). A number of mini-grids are operating under concession agreements or authorizations granted by the minister in charge of energy.[9]

The country's ambition is to sell the excess of its future electricity production to neighbouring countries. In addition, Guinea is a member of several subregional organizations such as the Gambia River Basin Development Organization (OMVG) and Senegal River Basin Development Organization (OMVS), which currently work together to develop shared hydropower sites on the territory of Guinea and for the implementation of transmission lines (the Côte d'Ivoire-Liberia-Sierra Leone-Guinea (CLSG) and Guinea-Mali interconnections).[10]

Although endowed with mineral and energy resources, the electricity sector of Guinea remains poorly developed. One of the objectives of the Development of the Energy Sector Policy (Lettre de Politique de Développement du Secteur Energétique, LPDSE) of December 2012 is to increase the global electrification rate from 12 per cent in 2014 to 50 per cent by 2020.[11] While significant progress has been made since 2014, the goal for 2020 has not yet been met. As of 2019, 58 per cent of the Guinean population remained without access to electricity (Figure 3).[12] The likelihood of rural access to electricity being provided by the national grid in the medium to long term is limited, while mini-grids are a cost-effective way to fill this gap in the interim.

Figure 3. **Electrification Rate in Guinea in 2019 (%)**



Source: World Bank[12]

The Government has developed a National Economic and Social Development Plan (PNDES) 2016–2020 that prioritizes renewable energy through decentralized solutions with the participation of the private sector.[13] The strategic purpose of the PNDES is to concretize the LPDSE as well as its Action Plan 2009–2025 to promote the development of a sustainable model based mainly on energy efficiency and renewable energy. Actions of the PNDES involve the promotion of decentralized solutions involving local authorities and the private sector at the rural level. This is in line with the Electricity Access Improvement Programme (2014) and the

Low-Cost Electrification Plan (2019). As for the electrification plans, the Government's strategy is to reach a large portion of the population with the extension of mini-grids.

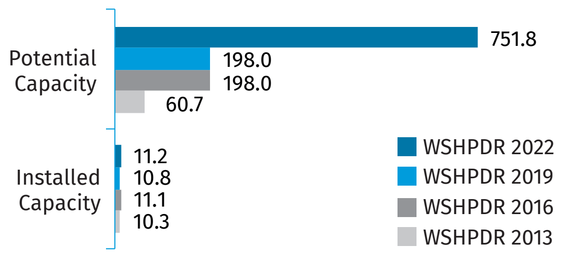
The green mini-grid programme, with support from the African Development Bank, will provide technical assistance to Guinea Agency for Rural Electrification (AGER), in the form of a help desk, for the deployment of 47 green mini-grids that have no prospect of being connected to the national grid in the next 10 years and that should allow the connection of approximately 60,000 households.[14]

The average price for electricity in 2019 was 0.064 USD/kWh (628 GNF/kWh), which indicates a 13 per cent decrease compared to average prices in 2018.[6]

SMALL HYDROPOWER SECTOR OVERVIEW

According to LPDSE, paragraph 23, micro-hydropower is defined as sites with installed capacity from 100 kW to 1,500 kW, whereas small hydropower (SHP) is not clearly defined.[15] For the purpose of this chapter, the up to 10 MW definition will be used. The total installed SHP capacity is 11.2 MW (Table 1), and has not meaningfully changed since the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 4). At the time of writing, the Banéah (5.6 MW) and Samankoun (0.24 MW) plants were undergoing renovation works, both not being connected to the central electricity grid (Table 1). Theoretical potential for hydropower plants under 10 MW amounts to 751.8 MW, revealing an increase of 280 per cent since the *WSHPDR 2019* due to new data from multiple studies.[16]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Guinea (MW)**



Source: EDG,[6] SIG,[16] *WSHPDR 2013*,[17] *WSHPDR 2016*,[18] *WSHPDR 2019*[19]

Note: Data for SHP up to 10 MW.

The French Development Agency (ADF) has agreed to co-finance four small dams: Fôkô (2.5 MW, multipurpose, Maritime Guinea), Bagata (2.2-5 MW, Middle Guinea towards Tougué), Founkeya Banko (4-5 MW, towards Dabola, Upper Guinea) and Lokoua (6-13 MW, Forest Guinea) (Table 2). These projects were undergoing technical and financial feasibility studies as of mid-2021.

Table 1. **List of Installed Small Hydropower Plants in Guinea**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Banéah*	Kindia	5.60	EDG	1989
Kinkon	Pita	3.44	EDG	1974
Tinkisso	Dabola	1.59	EDG	1969
Loffa	Macenta	0.16	EDG	1958
Samankoun*	Télémélé	0.39	EDG	1998 (approximate)

Source: EDG[6]

Note: *Under renovation.

Table 2. **Selected List of Planned Small Hydropower Projects in Guinea**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Developer*	*Stage of development*
Fôkô	Maritime Guinea	2.5	–	–	Feasability
Bagata	Middle Guinea	2.2-5.0	–	–	Feasability
Founkeya Banko	High Guinea	4.0-5.0	–	–	Feasability
Lokoua	Forested Guinea	6.0-13.0	–	–	Feasability
Touba	–	5.0	173	Tractebel Engineering France	Feasability

Source: SIE,[20] Tractabel Engineering[21]

One recent call for tenders in April 2021 from OMVG sought for consultants to perform feasibility studies on the Digan and Kourawel sites, with support from the African Development Bank, seeking technical, environmental and economic feasibility of the sites.[22]

Table 3. **List of Selected Small Hydropower Projects Available for Investment in Guinea**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/refurbishment)*
Daboya	Kolounkouré	2.8	37	New
Koukoutamba (Kalinko)	Bafing	6.3	15	New
Guessore	Sala	7.9	310	New
Ouességuélé	Ouességuélé river	0.9	25	New

Source: SIG[16]

The Atlas of Potential Hydropower in Guinea was put together by AECOM engineering firm, which compiled data from existing studies, such as Tractabel Engineering, and compared these findings with their own.[16] Several sites were then verified and further studied through site visits during the second stage of the process. This report identified new sites using advanced geographic modelling techniques and is the most up-to-date source for potential sites in Guinea as of mid-2021. Despite the identified vast potential of over 6,000 MW only 6 per cent of total known hydropower potential, large and small, has been developed.[16]

Several potential sites of larger capacities have encountered difficulties within the development process. The main causes of failure in hydropower development are: failure in creditworthiness in entering into a Power Purchase Agreement with EDG (as is the case with the Touba plant); change of the mining code leading to increased and complex costs (as is the case with Poudalde, 50–90 MW); and Build Operate Transfer (BOT) schemes, which encounter political problems and competing uses for the site of interest (as with the Fomi plant, 90 MW).

RENEWABLE ENERGY POLICY

The main objective, following the Energy for All initiative, is to increase the share of renewable energy sources in the country's energy mix to 30 per cent.[11] On the national policy level, the LPDSE outlined the following objectives:

- To reach a share of hydropower capacity in the grid electricity (excluding self-generation) of 70 per cent in 2017 compared to 38 per cent after the installation of 100 MW of emergency thermal power capacity in 2013;
- Develop 20 mini-hydropower plants of the inventoried 130 by 2025, including 5 by 2017, under PPP or community projects.[15]

Apart from planning, there are several concrete actions taken to further climate goals. Law L/2013/061/CNT authorizes the participation of private sector operators of plants less than or equal to 500 kW in capacity. The tariffs for the supply of electrical energy or electrical services and the conditions for their revision are established on a case-by-case basis in the specifications of the Electrification Authorizations. According to Article 30, Chapter II: Taxation of Title IV: Tariffs and Taxation, the tax regime applicable to companies holding a rural electrification permit is the most favourable regime of the Investment Code.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

For hydropower, the main policy angle is to prioritize the development of mini- and small-scale sites with respect to large subregional schemes to meet local needs. Ministerial Order A/2013/474/MEEF/CAB of 11 March 11 2013, which adopted the general environmental assessment guide, specifies that hydropower projects below 10 MW must be subject to an impact notice, while those greater than or equal to 10 MW must be subject to a detailed environmental impact assessment (EIA).

The process for attaining a licence for SHP projects is determined when the authorization or the concession is granted by means of orders of the Minister in charge of the electricity sector, following a call for tender procedure or on the basis of unsolicited applications. Law 98/012/AN of 1 June 1988 authorizes the financing, construction, operation, maintenance and transfer of development infrastructures by the private sector using Build-Own-Operate-Transfer (BOOT) contracts.[23]

The promulgation of Law L/93/039/CTRN of 13 September 1993 on the Production, Transport and Distribution of Electricity, limits the role of the state to the definition of: the energy policy and its instruments (price and tariff system; institutional, legal and regulatory framework), the monitoring of their application and the exercise of the control of the sector. This law was enacted to ensure the quality and continuity of the public electricity service.[24]

Other pieces of legislation pertaining to the SHP sector include: Law L/2013/061/CNT of 20 September 2013, Article 9 which defines the Rural Electrification Zone (ZER), National Rural Electrification Programme (PNER), Annual Rural Electrification Programme (PAER) and the Local Rural Electrification Initiative Projects (PILER).[25]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Some subsidies are set aside for small renewable generation under article 27, paragraph 2 of Law L/2013/061/CNT of 20 September 2013 on the rural electrification subsector. This law states that the Council for Rural Electrification must "ensure the implementation of the national policy of rural electrification as well as the proper use of resources and the optimal allocation of subsidies allocated by the Rural Electrification Fund (FER) for the development of sustainable access to electricity in rural areas, under conditions of acceptable technical, economic and financial viability, equity and transparency."[25] Financing is also available under the Programme of Decentralized Electrification (PERD) of the Office of Rural Decentralized Electrification (BERD) with co-financing from the World Bank and the Government of Guinea. This programme aims to conduct prefeasibility studies resulting in 12 locations to be selected for tendering for private investment in hybrid plants. The subsidy is estimated to amount to 60-80 per cent of initial investment costs, and has an expected closing date of December 2023.[26]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

According to studies on the effects of climate change on water systems in Guinea, water bodies will be significantly impacted up until 2100, with more significant effects seen in the second half of the century. The first national communication to the United Nations Framework Convention on Climate Change presented projection results by regions within the country on water flow reductions. Under a 1.5 °C scenario, water flow is expected to decrease by 2-8 per cent (depending on the region) by 2025 and by as much as 20-43 per cent by 2100. Under a 4.5 °C global warming scenario, regional decrease in water flow will reach between 6 and 16 per cent in 2025 and reach a reduction of between 34 and 73 per cent by 2100.[2] Several rivers have experienced negative effects due to flooding in recent years, including the Kankan (2001), Boké (2003) and Gaoual (2005).

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The following points summarize the main barriers to SHP development in Giunea that have been identified:

- Poverty of the population, especially in rural areas, and its impact on purchasing power;
- Financial barriers, such as the low national financing capacity (public and private) and subsequent high dependence on external public and private financing;
- Technological barriers including the huge technological backlog in energy industries and know-how as well as high expenses on technology and know-how transfer;
- Institutional barriers, particularly the lack of good overall governance and control of the development of the energy sector as a whole.

The following points summarize the main enablers for SHP development in the country that have been identified:

- There is a huge potential for SHP in the country and ample, available data on specific sites;
- Strong political motivation for mitigation of the negative effects of climate change;
- Interest in the country and financial aid from development institutions.

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Liberia

International Center on Small Hydro Power (ICSHP)

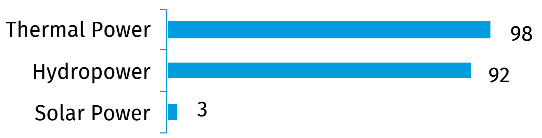
KEY FACTS

Population	5,057,677 (2020)[1]
Area	96,320 km^2 [2]
Topography	The topography of Liberia ranges from flat coastal lowlands to rolling hills and plateaus. Along the border with Guinea runs the Nimba Mountain Range and along the coastal plains are savannahs and degraded forests. The hills of the tropical forest and the montane forest zone are covered by dense rainforests. The highest point in the country, Mount Wuteve, culminates at 1,380 metres above sea level.[3]
Climate	Liberia has a warm and humid climate, especially on the coast. The rainy season lasts from May to October and the dry season from November to April. The dry and dusty desert wind from the Sahara brings relief from the high humidity. Mean annual temperatures in the country range from 18 °C in the northern highlands to 27 °C along the coast.[4]
Climate Change	The key effects of climate change observed in Liberia include droughts and increased temperatures, particularly during summer. An observed increase in heavy rainfall events, erosion and floods threaten many areas of economic and social life in the country. Between 1960 and 2006, mean annual temperature increased by 0.8 °C at an average rate of 0.18 °C per decade. This trend is projected to increase to 0.9 °C for the decades 2020-2039. The average number of hot nights has been increasing as well, with a reported increase of 57 nights. Concomitantly, the average number of cold nights has decreased by 18 days.[5]
Rain Pattern	Average annual rainfall in Liberia exceeds 2,500 mm. Rainfall is high along the coast but decreases towards the plateaus and low mountains. The southern areas receive more rainfall than the rest of the country with the area around Cape Mount receiving the most rainfall (5,200 mm).[4,6]
Hydrology	The Morro and Mano Rivers in the north-west and the Cavalla in the east and south-east of the country are the major rivers in Liberia forming sections of its borders. River traffic and short-distance navigation in most rivers are hindered by rapids, waterfalls and sandbanks that occur often in upstream sections of rivers. The Farmington River is a source of hydropower in the country.[4]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in Liberia are hydropower and thermal power. In 2019, total electricity generation in the country amounted to 226 GWh, of which hydropower accounted for 55 per cent and thermal power for 43 per. Solar power accounted for 4 GWh, or 2 per cent, of the total generation (Figure 1).[7]

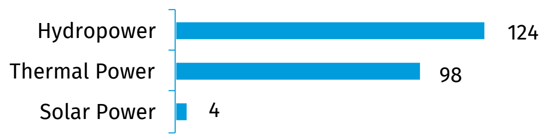
Figure 1. **Annual Electricity Generation by Source in Liberia in 2019 (GWh)**



Source: IRENA[7]

In 2020, the total installed electricity capacity in Liberia was 193 MW, of which thermal power, hydropower and solar power represented 51 per cent, 48 per cent and 1 per cent, respectively. The thermal power accounted for is non-renewable and amounts to 98 MW, whereas the hydropower capacity stands at 92 MW (Figure 2).[7]

Figure 2. **Installed Electricity Capacity by Source in Liberia in 2020 (MW)**

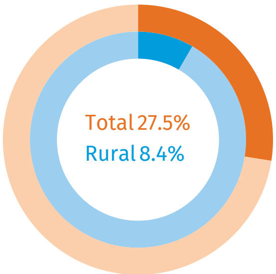


Source: IRENA[7]

In Liberia, the main electricity regulating body is the Liberia Electricity Regulatory Commission (LERC). LERC oversees the development and operation of the electricity sector as well issues licences for the generation, transmission, supply and import of electricity in the country. The main utility is the state-owned Liberia Electricity Corporation (LEC), founded in 1973. The LEC is in charge of the production, transmission and supply of electricity in the country.[8]

Liberia endured a 14-year civil war that greatly affected the country's infrastructure, including completely destroying the electricity sector. As a result, the electrification rate is one of the lowest in the world. In 2020, less than 28 per cent of the total population had access to electricity, with an 8 per cent access rate in rural areas (Figure 3).[9,10]

Figure 3. **Electrification Rate in Liberia in 2020 (%)**



Source: World Bank[9,10]

Considerable efforts have been undertaken by the Government of Liberia, international development partners and the LEC to rebuild and develop the electricity sector following the devastating damage from the civil war and post-war looting. Part of this effort was to construct addition transmission lines within the country. The Liberia Interconnected Transmission System operates at 66 kV and spans 128.7 kilometres and is expected to increase to over 248 kilometres upon completion of the ongoing transmission expansion projects. Some of these projects are the European Union–funded Monrovia Consolidation Project, the World Bank–funded Liberia Accelerated Electricity Expansion Project, the KfW Bank-funded Electrification and Grid Upgrade Project and the African Development Bank (AfDB)–funded Roberts International Airport corridor project.[8]

In line with the Sustainable Energy 4 All (SEforALL) initiative and the United Nations Sustainable Development Goals (SDGs), the Government of Liberia is committed to achieving a 20 per cent rural electrification rate as well as a total electrification of all county capitals, healthcare facilities and secondary schools by 2025. Under these initiatives, no country is to have an electrification rate below 15 per cent by 2030.[11]

Liberia is a member country of the Economic Community of West African States (ECOWAS). The ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) aims to support the development of renewable energy sources and energy action plans in the member states. Liberia is also part of the West African Power Pool (WAPP), a regional organization dedicated to fostering greater cooperation in the region's power sector and interconnection among countries to enhance energy security.[12]

The electricity tariffs in Liberia are some of the highest in the ECOWAS region, ranging from 0.15 USD/kWh to 0.24 USD/kWh.[8]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Liberia conforms to that of the Economic Community of West African States (ECOWAS), which is up to 30 MW. There are currently two operational SHP plants in Liberia: a 4.8 MW plant in Harbel, Margibi, operated by the rubber-producing company Firestone Plantation Company and a 60 KW plant in Yandohun, Lofa. The total installed capacity of SHP in Liberia is 4.86 MW (Table 1).[13,14]

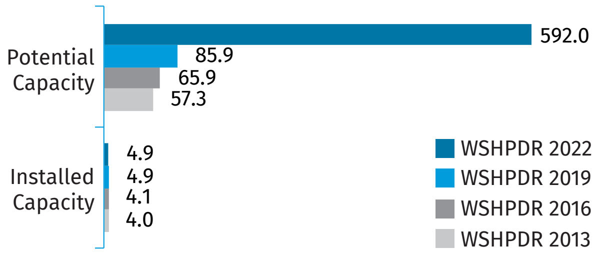
Table 1. **List of Operational Small Hydropower Plants in Liberia**

Name	*Location*	*Capacity (MW)*	*Operator*
Harbel	Margibi County	4.80	Firestone Plantation Company
Yandohun	Lofa County	0.06	Yandohun Electricity Development Cooperative

Source: Renewables Liberia[13,14]

In order to determine the SHP potential of Liberia, studies were conducted in 2015 by the European consultant company AFRY (then-Pöyry Energy GmbH) for the ECREEE. An estimated theoretical SHP potential of 592 MW was identified and published in the GIS Hydropower Resource Mapping and Climate Change Scenarios for the ECOWAS Region, Country Report for Liberia.[15] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, estimated potential increased considerably based on data from a more recent and thorough study, whereas the installed capacity has remained unchanged (Figure 4). Table 2 shows a list of some planned SHP projects.

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Liberia (MW)**



Source: ECREEE,[15] *WSHPDR 2013*,[16] *WSHPDR 2016*,[17] *WSHPDR 2019*[18]

Table 2. **List of Selected Planned Small Hydropower Projects in Liberia**

Name	*Capacity (MW)*
Gbedin Falls	9.34
Kaiha	2.50
Kaiha 2	2.50

Source: Hydro Review,[19] RREA[20]

RENEWABLE ENERGY POLICY

Liberia does not have a consolidated renewable energy policy document. In 2007, the Government of Liberia drafted a Renewable Energy and Energy Efficiency Policy and Action Plan (REEEPAP) that emphasizes the importance of renewable energy and prioritizes the creation of the Rural and Renewable Energy Agency (RREA). The RREA was subsequently created in 2010 with the mission to promote the commercial development and supply of energy in rural areas in order to facilitate their economic development. The REEEPAP also recognizes the great potential for and importance of SHP development.[21,22]

In addition to the REEEPAP, in 2009 the Government of Liberia developed a National Energy Policy (NEP) with a long-term strategy to achieve carbon neutrality in energy production and transformation by the year 2050. This strategy is aligned with Liberia Rising Vision 2030, the country's development strategy for inclusive development.[21]

Liberia is a signatory to the United Nations Framework Convention on Climate Change (UNFCCC), the Kyoto Protocol and the Paris Agreement. In 2021, the Government of Liberia updated its Nationally Determined Contribution (NDC) and, as part of its mitigation targets, commits to developing off-grid SHP by developing several sites with 20 MW capacity by 2030. The NDC also highlights the importance of solar power and commits to installing 10 MW of solar photovoltaic (PV) plants by 2025 through partnerships with independent power producers (IPPs).[21]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP plants are regulated by the same legislation as larger hydropower projects. The main legislation and regulation documents in Liberia concerning hydropower projects are:

- The Electricity Law (2015);
- Executive Order No. 23 on the creation of the RREA (2010).

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The development of SHP in Liberia is mainly hampered by:

- The lack of a comprehensive renewable energy policy with a clear strategy for SHP development;
- Deficient electricity network due to extensive infrastructure damage from war;
- Lack of local capacity for the installation and maintenance of SHP plants;
- Limited availability of hydrological data.

Enablers for SHP development in Liberia include:

- Specific mention of the importance of SHP development in the country's NDC and REEEPAP;
- Plans to promote private sector investment in SHP as outlined in the country's NDC;
- Thorough assessment of SHP potential as outlined in the GIS Hydropower Resource Mapping and Climate Change Scenarios for the ECOWAS Region, Country Report for Liberia.

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Mali

Davy Rutajoga, International Center on Small Hydro Power (ICSHP)

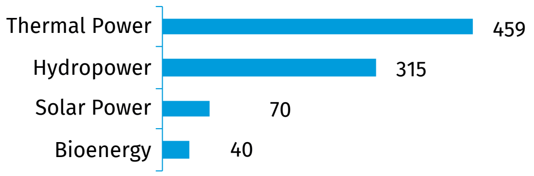
KEY FACTS

Population	20,250,834 (2020)[1]
Area	1,240,192 km^2[2]
Topography	Mali is a mostly flat country with occasional high-rising plateaux. Almost half of the country is covered by the Sahara Desert in the north. The open steppes of Akle Azaouad (AKA) plateau and the rocky terrain of Adrar-Timetrines and of Tilemsi from east to north. The southern part of the Sahara Desert in Mali transitions into the Sahel Region, interrupted in central Mali by the alluvial plains of the Inland Niger Delta. The majority of the country's agricultural land is found in southern Mali, in the plains of the Sudanian Region.[3]
Climate	Lying within the intertropical zone, Mali has a hot and dry climate as the sun nears its zenith throughout most of the year. There are two main seasons: dry and wet seasons. The dry season (November–June) is marked by high temperatures and low humidity, with daytime temperatures reaching 45 °C. The wet or rainy season (June-October) is characterized by gusty winds and heavy rainfall. Temperatures in the Sahara Desert can range from daytime extremes of 60 °C and night temperatures of 4 °C.[2]
Climate Change	Mali is affected by global warming, with mean annual temperatures having increased by 0.7 °C since 1960 at an average rate of 0.15 °C per decade. This increase is observed especially in the hot and dry season. The frequency of nights considered hot has increased considerably, except in the months of December to February. Droughts have also increased, particularly in the northern regions, and a decrease in rainfall has been observed.[4]
Rain Pattern	Mali experiences variable rainfall throughout the country, with the southern Sudanian regions receiving annual rainfall of between 510 mm and 1,400 mm and the Sahelian Region receiving between 200 mm and 510 mm. The mean annual precipitation in Mali is 322 mm.[2,4]
Hydrology	Two main rivers cut through Mali: the Senegal River and the Niger River. The Niger River, which runs through the country for over 1,600 km, flows north-east across the Mandingue Plateau and is interrupted by waterfalls and a dam at Sotuba. The Senegal River runs through Mali for 670 km and flows towards the Atlantic Ocean in a north-west direction.[2]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in Mali are thermal power and hydropower, accounting for 61 per cent and 37 per cent, respectively, of total electricity production of 3,952 GWh in 2019. Bioenergy and solar energy contributed 67 GWh and 4 GWh, or less than 2 per cent and 0.1 per cent, respectively, of the total production that year (Figure 1).[5]

Figure 1. **Annual Electricity Generation by Source in Mali in 2019 (GWh)**

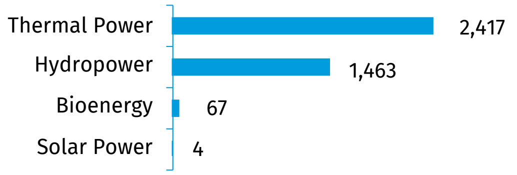


Source: IEA[5]

Most of the hydropower consumed in Mali is generated by the 200 MW Manantali hydropower plant, which also supplies most of the hydropower consumed by the neighbouring countries of Senegal and Mauritania, and by the 60 MW Felou plant shared with Senegal. Mali is also home to the largest solar plant in Western Africa: the 50 MW Kita plant. The electricity shared with neighbouring countries is part of the Synchronized Western Network, a subgroup of the West African Power Pool (WAPP) that connects four countries of the Economic Community of West African States (ECOWAS): Mali, Senegal, Niger and Burkina Faso.[5]

In 2020, Mali had 459 MW of installed thermal power capacity representing approximately 52 per cent of the total installed electricity capacity of 884 MW. Hydropower accounted for 315 MW or 36 per cent of the total installed capacity. Installed solar power and bioenergy capacities were 70 MW and 40 MW, respectively, or almost 8 per cent and 5 per cent of the total installed electricity capacity (Figure 2).[6]

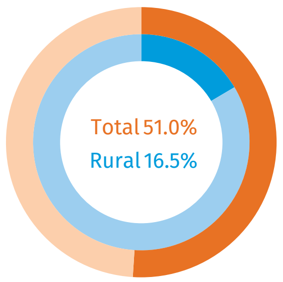
Figure 2. **Installed Electricity Capacity by Source in Mali in 2020 (MW).**



Source: IRENA[6]

In 2020, the total rate of access to electricity in Mali was 51 per cent, with the rural electrification rate being less than 17 per cent (Figure 3).[7]

Figure 3. **Electrification Rate in Mali in 2020 (%)**



Source: World Bank[7]

Electricity in Mali is supplied by Energie du Mali SA (EDM-SA) through three separate electric systems: the interconnected system, the isolated centres and the interconnection with the grid of Côte D'Ivoire. Until 2010, the EDM-SA was the sole entity allowed to produce, transmit, supply, commercialize and export electricity in Mali. Since 2010, the Electricity and Water Regulatory Board (CREE), which is mandated by a ministerial decree to regulate the electricity sector and clean water supply in urban centres, has been able to authorize third parties to access the national grid. Rural off-grid energy services with generation systems below 250 kW are provided by independent operators through the Malian Agency for the Development of Household Energy and Rural Electrification (AMADER).[8,9,10]

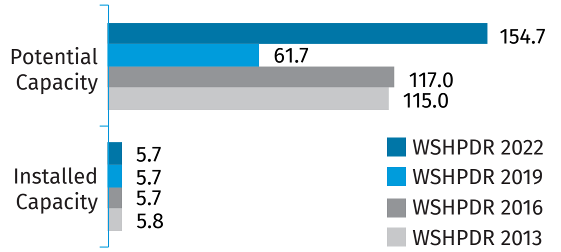
In 2001, the Government of Mali committed, through partnership, to the Sustainable Energy for All (SEforALL) with the aim of providing electricity access to at least 87 per cent of the population by 2030. In 2006, the Government debuted the National Energy Policy (PEN) to support and strengthen the energy sector and its contribution towards a sustainable economic and social development. In 2014, the Government launched the National Renewable Energy Action Plan 2013–2033 (PANER) in order to address the specific issue of renewable energy (RE).[8,11]

The electricity tariffs in Mali are subsidized by the Government and have not increased in any significant manner over the years. In 2018, the tariffs were between 0.11 USD/KWh and 0.25 USD/KWh. There are no recent tariffs published by official sources, however it can be assumed that they have not varied significantly.[12]

SMALL HYDROPOWER SECTOR OVERVIEW

In Mali, small hydropower (SHP) refers to plants with installed capacity of up to 30 MW. There is currently one operational SHP plant, the 5.7 MW run-of-river Sotuba plant. The country has an estimated SHP potential of up to 154.7 MW, a 150 per cent increase from the estimated potential in the *World Small Hydropower Development Report* (*WSHPDR*) *2019* (Figure 3). This increase is based on newer studies of various sites as included in the Renewables Readiness Assessment of Mali by the IRENA.[12]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Mali (MW)**



Source: IRENA,[12] *WSHPDR 2013*,[13] *WSHPDR 2016*,[14] *WSHPDR 2019*[15]

In 2020, the Ministry of Energy and Water invited sealed bids for the design, commissioning, installation and supply of a 7.5 MW SHP plant in Djenné designed to supply 5,200 local households with electricity. The Djenné plant is one of the two SHP plants with a combined capacity of 8.9 MW that are being developed under the Mini-Hydropower Plants and Related Distribution Networks Development Project (PDM-Hydro), the other one being located in Talo. As of 2022, the Government was in the process of environmental and social audits in preparation for the construction of the SHP plants.[16,17]

Table 1. **List of Selected Planned Small Hydropower Projects in Mali**

Name	*Capacity (MW)*
Moussala	30.0
Taoussa	20.0
Gourbassi	13.0
Markala	10.0
Djenné	7.5
Sotuba II	6.0
Kourouba	3.9
Talo	1.4

Source: IRENA,[12] Hydropower & Dams,[16,17] GOPA-INTEC[18]

In addition to the Djenné and Talo plants, the Government launched a project to build a new 3.9 MW SHP plant on the Sankarani River. This plant, located in the Kourouba region, aims to bring electricity to approximately 20,000 people in the region. The consulting services for this project are courtesy of the German GOPA International Energy Consultants (GOPA-INTEC) and are financed by the African Development Bank (AfDB).[18]

RENEWABLE ENERGY POLICY

Concomitantly with the NEP, the Government of Mali formulated a National Strategy for the Development of Renewable Energies and, in 2008, a National Strategy for the Development of Biofuels. The objectives of these policies were to promote widespread use of RE technologies as well as creating the best conditions for the sustainability of RE services. The Latter policy emphasized the development of indigenous energy sources, which are renewable and readily available.[11] In 2011, the Climate Investment Fund (CIF) approved the Scaling up Renewable Energy Programme (SREP), which aimed to assist in the development of RE in Mali. The SREP comprised three investment projects:

- The Scatec project for the development of solar energy;
- The project to build solar photovoltaic (PV)/biofuel hybrid hydropower systems in rural areas;
- The Mini-Hydropower Plants and Related Distribution Networks Development Project (PDM-Hydro).[19]

The Scatec project has progressed with the company Scatec Solar and its partners signing an amendment with the Government of Mali, in 2019, for the production of solar energy. The project is funded by the Norwegian Agency for Development Corporation (NORAD), the International Finance Corporation (IFC) and AfDB. The funding also includes a concessional loan from the CIF of USD 20 million under the SREP. The Scatec project signed a power purchase agreement (PPA) with the EDM-SA in 2015 to build, own, operate and maintain a 33 MW solar power plant with a 51 per cent shareholding. Annual production of the plant is expected to be approximately 57 GWh.[19,20]

The PDM-Hydro project aims to enhance access to electricity in rural areas, particularly in the regional provinces of Mopti and Ségou where much of the studies were conducted. An estimated 12,500 households and economic operators are expected to be connected through the project.[19]

In 2014, the Government adopted the National Renewable Energy Action Plan 2013–2033 (PANER) and the National Energy Efficiency Plan (PANEE). The two strategies were merged in 2015 for a consolidated National Renewable Energy Action Plan (NREAP) that follows SEforALL guidelines and sets targets for 2030 including 1,416 MW of installed RE capacity.[11]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The main legislation and regulation documents in Mali concerning hydropower projects are:

- Electricity Law No. 90-10/AN-RM (1990);
- Order No. 00-019/P-RM (2000) on the organization of the energy sector;
- Order No. 00-021/P-RM (2000) on the creation of the CREE.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Observed hydrological trends in the Niger Basin, where the Sotuba SHP plant is located, highlight a negative impact on the performance of the hydropower plant. Since 1907, a high inter-annual flow variability has been observed, culminating in a decrease in annual flow since 1970. In addition to this flow variability, a decrease in groundwater levels of tributaries to the Niger River has been observed, leading to a runoff deficit[11]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

SHP development in Mali is mainly hampered by:

- Difficult return on investment due to high investment costs and the need for an affordable price of kWh for poor households;
- Climate change affecting performance of hydropower plants through inter-annual flow variability;
- Concerns over the pollution of rivers due to the deployment of distribution lines, which may leave construction and packaging material onsite;
- Concerns of indigenous populations over changes to their lifestyles due to construction of power plants, such as pollution from construction through deposit of building and construction material;

Enablers for SHP development in Mali include:

- Government policies that focus on RE and the importance of mini-grid projects in rural areas encourage adequate solutions such as SHP;
- International funding for SHP projects through the PDM-Hydro project;
- The prospect of job creation brought about by construction, operation and maintenance of SHP plants, which would help alleviate social issues in Mali.

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Mauritania

International Center on Small Hydro Power (ICSHP)

KEY FACTS

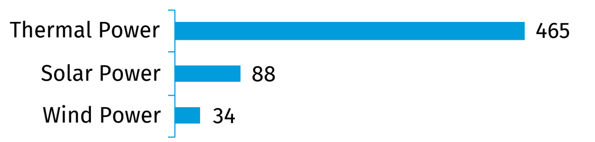
Population	4,649,660 (2020)[1]
Area	1,030,700 km^2 [2]
Topography	The country is generally flat with three geographic regions: a broad east-west band with vast plains and dunes; a narrow belt along the Senegal River to the south; and a large arid region to the north, which shades into the Sahara. Every year, the desert advances south several kilometres and brings shifting sand dunes. The highest point in the country is Mount Ijill, located near Fdérik and standing at 915 metres above sea level.[3]
Climate	Mauritania has a hot, dry and windy climate. There is sparse rainfall throughout the year for most of the territory, with the situation being worsened by the effects of rapid desertification. To the south, at the Sahelian border, the wet season is controlled by the Inter-Tropical Convergence Zone (ITCZ). The country's mean monthly temperature stays above 25 °C for most of the year, with peak temperatures of 33 °C in June and July.[4,5]
Climate Change	Mauritania is greatly affected by climate change, with the main consequences being the irregular rainfall patterns and the increasing temperatures in an already hot area. The mean annual temperature has increased by 0.9 °C since 1960 and is expected to further increase by 2-4.5 °C by 2080. The country has also been experiencing more frequent and more intensive bouts of droughts and floods, as well as a decrease in the water supply of the Senegal River. This poses a threat to the agricultural and fishing industries, which are essential for the country's economy. The global rise in sea level exposes the country to a risk of flooding of the infrastructure located on the coast. The sea level is projected to rise by 10 cm by 2030, 19 cm by 2050 and 36 cm by 2080. This risk is of particular concern to the capital and economic centre of Mauritania, Nouakchott, located on the shoreline.[5,6]
Rain Pattern	Most of Mauritania receives very little rainfall throughout the year. Annual precipitation ranges from 20 mm on the northern coast to approximately 400 mm in the central south. The southern region, at the edge of the Sahel, has a wet season between July and September with up to 200 mm of rainfall in each of those months. Changes in rainfall patterns are difficult to monitor as daily rainfall observations are limited.[5,7]
Hydrology	In Mauritania, surface water is the main water resource, of which the Senegal River and its tributaries constitute the main part. There are also considerable groundwater resources, though they are geographically disparate and play a very limited role in the country's social and economic context. Due to the country's location in a considerably arid region, there is a dependence on outside sources to meet the water demand.[8]

ELECTRICITY SECTOR OVERVIEW

The main source of electricity in Mauritania is thermal power, accounting for 863.4 GWh or almost 80 per cent of the 1,087.4 GWh generated in the country in 2020 (Figure 1). Wind and solar power accounted for approximately 11 per cent and 10 per cent of the total generation, respectively (or 115.3 GWh and 108.7 GWh).[9]

Electricity in Mauritania is owned, transmitted and distributed entirely by the Mauritanian Electricity Company (SOMELEC). There are no individual power producers in the country. SOMELEC, founded in 2001 following the demerger of the National Water and Electricity Company (SONELEC), operates in 58 cities and dozens of towns across Mauritania. The company also owns shares in the Manantali and Félou hydropower plants in neighbouring Mali.[9] In this report, the imported electricity from these plants is not accounted for in the total annual electricity generation of Mauritania, but rather in that of Mali.

Figure 1. **Annual Electricity Generation by Source in Mauritania in 2020 (GWh)**

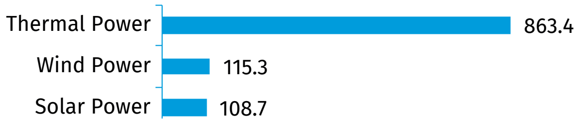


Source: SOMELEC[9]

The electricity sector of Mauritania is regulated by the Department of Electricity and Energy Management (DEME) of the Ministry of Petroleum, Energy and Mines (MPEM). DEME is in charge of both the national grid and off-grid electricity production. It regulates the work of SOMELEC and the Agency for the Development of Rural Electrification (ADER).[10]

In 2020, the total installed capacity in Mauritania was 587 MW, with the thermal power plants of SOMELEC accounting for 79 per cent (or 465 MW), the solar power farm accounting for 15 per cent (or 88 MW) and the wind farms accounting for 6 per cent (or 34 MW) (Figure 2).[11]

Figure 2. **Installed Electricity Capacity by Source in Mauritania in 2020 (MW)**

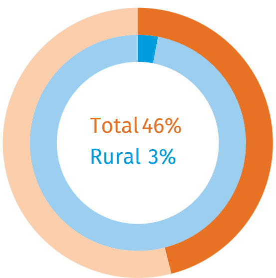


Source: IRENA[11]

As part of its Nationally Determined Contribution (NDC 2021–2030), Mauritania aims to reach a target of 13 GW of renewable energy in its energy mix by 2030.[6] The country also joined the Sustainable Energy for All (SE4ALL) initiative in 2014 and therefore adheres to the initiative's goal of doubling the share of renewable energy in the global energy mix by 2030.[12] The Government of Mauritania also aims to reach a national target rate of electrification of 70 per cent by 2030, with 95 per cent in urban areas and 40 per cent in rural areas as part of the country's Strategy for Accelerated Growth and Shared Prosperity (SCAPP) 2016–2030.[13]

As of 2020, the average price of electricity for a standardized connection in Mauritania was 0.176 USD/kWh.[14] In 2019, less than 46 per cent of the population had access to electricity, with 87 per cent in urban areas and 3 per cent in rural areas (Figure 3).[15,16,17]

Figure 3. **Electrification Rate in Mauritania in 2019 (%)**



Source: World Bank[15,16]

SMALL HYDROPOWER SECTOR OVERVIEW

There was no small hydropower (SHP) sector in Mauritania as of 2021. All existing plants in the country are large-scale and all hydropower generation is imported. The potential for SHP is unknown. However, the country is expected to have some limited SHP potential in the south, which could be exploited to provide electricity to smaller communities. This potential, however, still remains to be studied.[12]

RENEWABLE ENERGY POLICY

As part of the SCAPP, the Government of Mauritania aims to promote access to electricity in rural areas. There is, however, no official implementation plan for rural electrification policy. In 2014, the Renewable Readiness Assessment, launched by the International Renewable Energy Association (IRENA) and the United Nations Development Programme (UNDP) provided Mauritania with a study of the conditions and potential for renewable energy development. Following this assessment, the Government of Mauritania developed a high-priority renewable energy development programme for 2015–2018 as an alternative to the lacking integrated national electrification plan.[13] Since 2019, Mauritania has been part of the African Development Bank-led Desert to Power West Africa Regional Energy Programme (WAREP), which aims to provide access to electricity and enable socio-economic development in the Sahel region by harnessing the available solar power potential and adding 10 GW of solar photovoltaic generation capacity by 2025.[18]

The electricity sector of Mauritania is governed by the Electricity Code (2001–2019). The Master Plan for the Generation and Production of Electricity (2013), a long-term strategy for the development of the electricity sector in Mauritania, has been the main framework of reference for the future of the sector. However, it needs to be revised and updated to reflect the unsuccessful market liberalization strategy as SOMELEC retains monopoly of the electricity sector in the country.[13]

Due to the lack of a sufficient regulatory framework for access to sustainable energy, in 2017 Mauritania marked a relatively low score of 24 out of 100 on the World Bank Regulatory Indicators for Sustainable Energy (RISE) evaluation, placing it among the lowest scoring access-deficit countries in the world.[13]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

There is no legislation or regulations that target SHP in Mauritania. As the SHP potential is limited and there are no immediate plans for SHP development, the country's hydropower resources are all imported from Mali.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

As there are no SHP plants in Mauritania, the development of future plants is hindered by:

- The lack of sufficient data on hydropower resources

in the country;
- The lack of a comprehensive legal and regulatory framework;
- The focus of the Government's efforts on the development of other renewable energy sources with more potential, such as solar and wind power.

The known enabler for SHP development in Mauritania is:
- The SHP potential identified in the southern part of the country, which could provide some electricity to smaller communities.

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Niger

International Center on Small Hydro Power (ICSHP)

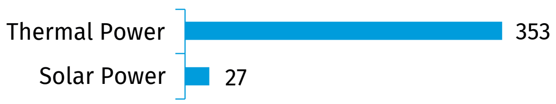
KEY FACTS

Population	24,206,636 (2020)[1]
Area	1,266,700 km^2 [2]
Topography	Niger is located in the Sahel region, a transitional zone between the Sahara Desert, which covers approximately 65 per cent of the country, and tropical Western Africa. This area is made up of shifting sand dunes, broad gravel and stony plains. Across central Niger, the pastoral areas of the Manga and Azouak regions form a wide streak of savannahs and steppes. Southern Niger is more productive, home to the Maradi-Zinder region, the largest agricultural region in the country.[3]
Climate	Niger is characterized by very high temperatures all year-round. An intense dry season from October to May is replaced by a brief, irregular rainy season brought about by the Western-African monsoon. The mean annual temperature is 27.9 °C with cooler temperatures in mountainous regions.[4]
Climate Change	Niger experiences the effects of global warming, with its mean annual temperature having increased by 0.6-0.8 °C between 1970 and 2010, higher than the global average. An increase in hotter days and nights has been observed. Rainfall has been variable from year to year and has not returned to the pre-1960s levels. The rainy seasons are shorter and harder, with an increase in extreme rainfall events and floods.[4]
Rain Pattern	With its irregular and brief rainy season, Niger enjoys relatively little rain, particularly in the northern regions, which experience 100–200 mm of rainfall. The southern regions enjoy more rain (500–600 mm), which is limited to the summer months of June–September. The mean annual precipitation is 179.6 mm.[4]
Hydrology	Niger is a dry country and has relatively poor hydrology. The main rivers in the country are: the Tapoa, Mékrou, Sirba, Dargol, Gorouol, Goroubi, Diamangou and the Niger River, the third largest river in Africa (4,200 kilometres in length, of which 500 kilometres run through Niger). Other important water bodies include Komadougou Yobé, Lake Chad and the ponds of Madarounfa, Tabalak and Guidimouni. There are important underground resources with a relatively deep groundwater level in the northern area of the country.[5]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in Niger are thermal power and, to a much lesser extent, solar power. In 2019, the total electricity production amounted to approximately 555 GWh, of which thermal power accounted for 94 per cent, or 523 GWh, and solar power accounted for 6 per cent or 33 GWh (Figure 1).[6]

Figure 1. **Annual Electricity Generation by Source in Niger in 2019 (GWh)**

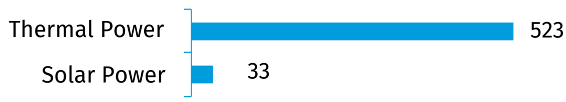


Source: IRENA[6]

The Niger Electricity Company (NIGELEC) was founded in 1968 and has a monopoly on transmission and distribution of electricity the country. In addition to the NIGELEC operations, the Coal Company of Anou Araren (SONICHAR) produces electricity from a thermal coal power plant and sells it to mining companies and has a quasi-monopoly on distribution in the cities of Agadez, Arlit and Tchirozérine.[7] The diesel and coal thermal power plants continue to play a major role in the production of electricity in the country, despite the fact that these facilities are relatively old and many have reached the age of decommissioning.[8]

In 2020, the total installed electricity capacity in Niger was 380 MW, of which thermal power represented 93 per cent. Installed solar power capacity amounted to 27 MW, or 7 per cent of total installed capacity (Figure 2).[6]

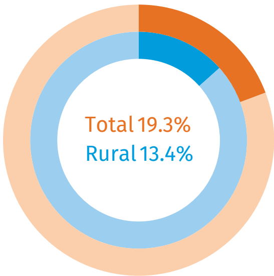
Figure 2. **Installed Electricity Capacity by Source in Niger in 2020 (MW)**



Source: IRENA[6]

The total electrification rate in Niger in 2020 was 19 per cent, with rural access being 13 per cent, one of the lowest in the region (Figure 3). By 2030, the country aims to reach 100 per cent electricity coverage in urban areas and 30 per cent in rural areas. According to the Project for the Electrification of Rural and Urban Areas (PEPERN), the plan should target at least 46,000 households.[9,10,11]

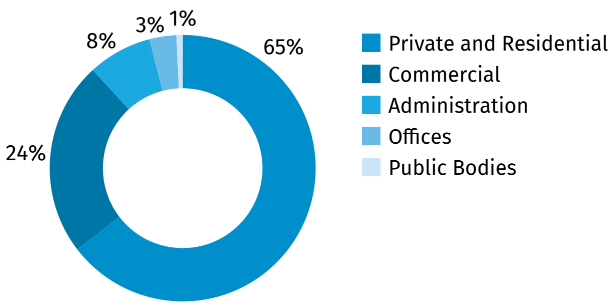
Figure 3. **Access to Electricity in Niger in 2020 (%)**



Source: World Bank[9]

In Niger, private and residential consumers represented the greatest share of electricity buyers (almost 65 per cent) and local public bodies the lowest (0.8 per cent) in 2020 (Table 1).[12]

Figure 4. **Consumption Rates by Consumer Category in Niger in 2020**



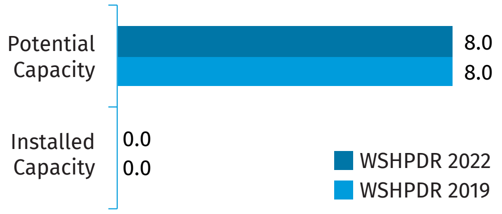
Source: NIGELEC[12]

The electricity subsector in Niger is regulated by the Regulation Authority of the Electricity Sector (ARSE), which is also responsible for advising the Ministry of Energy, Petroleum and Renewable Energies on electricity tariffs, among other duties.[13] Following Decree No. 2017-796/PRN/ME of 2017, electricity tariffs are fixed in Niger, between 0.097 USD/kWh and 0.22 USD/kWh depending on the consumer category (residential, commercial, etc.) and electricity requirement (low voltage, medium voltage, high voltage). There are also options for subscription-based billing for up to 21 USD per month.[14]

SMALL HYDROPOWER SECTOR OVERVIEW

Niger does not have an official definition for small hydropower (SHP). For the purposes of this chapter, the 10 MW definition will be followed. At the moment, Niger does not have any installed SHP capacity. A combined potential of 8 MW was identified on the four rivers that flow into the Niger River (Gorouol, Tapoa, Sirba and Mékrou). This potential remains untapped due to the seasonality of the Niger River's tributaries as well as the increase in droughts experienced by the country's water bodies. Both installed and potential capacity remain unchanged compared to the *World Small Hydropower Development Report (WSHPDR)* 2019 (Figure 5).[14,15]

Figure 5. **Small Hydropower Capacities in the WSHPDR 2019/2022 in Niger (MW)**



Source: Ministry of Energy, Petroleum and Renewable Energies,[14] *WSHPDR 2019*[15]

In 2019, construction began on the Niger River of a dam and a 130 MW hydropower plant. The project, called the Kandadji Dam Project, is expected to be completed in 2031 and is a first step towards the prospective development of hydropower in Niger.[16]

RENEWABLE ENERGY POLICY

Niger is a member of the Economic Community of West African States (ECOWAS) and as such adopted the National Renewable Energy Action Plan (NREAP) that all 15 member-states adopted in 2015. The NREAP addresses all sources of renewable energy, including wind power, solar power, thermal power, tidal power and hydropower, and highlights the importance of their development and the contribution that renewable energy would bring to the country.

The NREAP specifies the need for the development of hydropower through the construction of the 130 MW Kandadji plant, a 122 MW hydropower plant in Gambou and a 90 MW hydropower plant in Namarigoungou. These plants are expected to contribute greatly to the country's energy mix. Under the NREAP, Niger is committed to exploiting its renewable energy potential to achieve universal electricity coverage by 2030.[14]

The renewable energy potential in the country is mostly untapped. In 2018, with the support of the World Bank, Niger launched the Niger Solar Electricity Access Project (NESAP). The project of approximately USD 50 million (USD 4.4 million from a donation and a USD 45.55 million loan) aims at improving access to electricity through solar power. NESAP falls within the Renaissance Act 2 of the Republic of Niger aimed at improving the rural electrification rate. In order to reach its targets, Niger has received funds from the International Development Association (AID).[17]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

There is currently no legislation regulating SHP as there is no developed hydropower in Niger. The main legislation and regulations documents in Niger concerning the electricity subsector include:

- Law No. 2016-05 (2016) on the electricity code;
- Law No. 2015-58 (2015) on the creation of the ARSE;
- Order No. 2010-09 (2010) on the Water Code.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Extreme precipitation variability in the Sahel region has affected hydropower in the Sahelian countries. This variability has also resulted in increased droughts and seasonality of the Niger River's tributaries, which considerably affects SHP development prospects.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The development of SHP projects in Niger is mainly hampered by:

- Irregularity of rainfall patterns, which affects SHP development, further exacerbated by climate change;
- Lack of comprehensive renewable energy policy which would set specific goals, including for hydropower;
- Limited experience in hydropower as there is currently no hydropower plant in the country, although construction has begun on one and is expected to be completed in 2031;
- Dependence on fossil fuels for energy production.

Enablers for SHP development in Niger include:

- Its location within the ECOWAS region, which provides an opportunity for the country to learn from and acquire expertise in hydropower from other member countries with developed SHP;
- Identified SHP potential, which, if developed, would improve electrification rates in the country.

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Nigeria

Paola Estenssoro Solíz and Cleber Romao Grisi, WHITEnergy Bolivia

KEY FACTS

Population	206,139,587 (est. 2020)[1]
Area	923,768 km^2 [2]
Topography	Nigeria is dominated by plains in the north and the south, with an average elevation of 609.5 metres. In the north, the Jos Plateau rises abruptly to a height of 1,219 metres in the Hausa Plains, reaching 1,781.6 metres in the Shere Hills. The eastern border with Cameroon is marked by an almost continuous chain of mountains, the Eastern Highlands, which rise to approximately 2,419 metres at the Chappal Waddi, the highest point in Nigeria. The Atlantic coastline is in the south of the country.[3]
Climate	Nigeria has a tropical climate with rainy and dry seasons, which vary depending on the location. The climate is hot and wet most of the year in the south-east of the country, but dry in the south-west and further inland. In the south, the rainy season lasts from March to November with a short dry season during August, referred to as the August Break, whereas in the far north it lasts from mid-May to September. The temperatures also vary a lot: in the north, winters are warm and dry reaching up to 40 °C, while northern hilly areas occasionally experience temperatures close to freezing (0 °C). By February, temperatures increase across all inland areas, reaching 40 °C in the centre-north from March to May. From June to September, the air is humid and sky is usually cloudy throughout the country, with uniform temperatures of 28–30 °C.[4,5]
Climate Change	Climate change projections for Nigeria predict an increase in maximum temperatures of 1.8–2.2 °C by the middle of the 21st century and of 2.2–4.5 °C by the end of the century, relative to the 1970–2000 period. The increase in maximum temperatures is expected to be the highest in the northern inland parts of the country, moderate in the centre and lowest in the coastal areas. This would reverse the trend observed during the 1970–2000 period, when the increase in temperatures was more significant on the coast than inland.[6]
Rain Pattern	The mean annual rainfall in the country is between 2,540 mm and 4,064 mm. The driest area in the country is the extreme north-east, where the average annual precipitation is below 500 mm, while in the central region it exceeds 2,000 mm and in the south-east 3,000 mm. The north of the country is drier than the south due to the influence of the coast line.[3,5,7]
Hydrology	There are three major basins in Nigeria: the Niger-Benue basin, the Lake Chad basin and the Gulf of Guinea basin. The Niger and the Benue Rivers are the two most important rivers in Nigeria. The two rivers converge at Lokoja forming a Y-shaped confluence and flow into the Niger Delta, one of the world's largest arcuate fan-shaped river deltas, before discharging into the Atlantic Ocean. Rivers in Nigeria generally show a marked seasonal variation in stages and discharges. The distribution of average monthly water levels at some gauging stations shows that a large proportion of the annual runoff occurs in the rainy season, occasionally causing floods. During the dry season, some of the smaller streams, especially in the northern parts of the country, virtually dry up, while the larger rivers are reduced to only a small fraction of their rainy season discharge.[3,4]

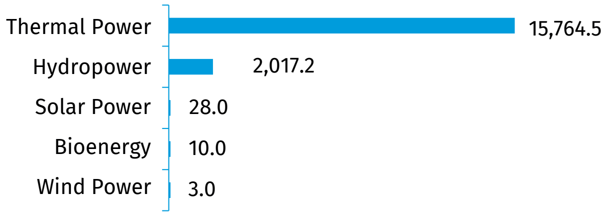
ELECTRICITY SECTOR OVERVIEW

As of 2020, Nigeria had a total installed capacity of 17,822.7 MW. Of this total, thermal power accounted for 15,764.5 MW (88 per cent), primarily provided by gas-fired power plants. Hydropower provided 2,017.2 MW (11 per cent) and the remaining 41 MW (less than 1 per cent) were provided by wind power, solar power and bioenergy (Figure 1).[8,9,10,11]

Most of the electricity capacity in Nigeria is connected to the national grid, with the exception of small hydropower (SHP) and wind power. Since the electricity supply from the national grid is insufficient and unstable, electricity production on isolated networks, mainly for self-consumption, plays a prominent role in the country.[12]

In 2021, there were 29 power plants suppling electric energy to the national grid, of which 4 were hydropower plants and 25 thermal plants. The main sources of hydropower are the Kainji (760 MW), Jebba (570 MW) and Shiroro (600 MW) hydropower plants.[8,9,13]

Figure 1. **Installed Electricity Capacity by Source in Nigeria in 2020 (MW)**

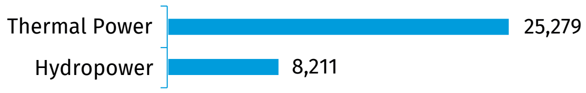


Source: NERC,[8,9] IRENA,[10] Romao Grisi & Estenssoro Solíz[11]

The transmission network of the national gird has a total length of 12,300 kilometres (5,650 kilometres of 330 kV lines and 6.687 kilometres of 132 kV lines) and connects 32 330 kV and 105 132 kV substations. The distribution network has a length of 224,838 kilometres consisting of 33 kV, 11 kV and low-voltage lines.[14]

In 2019, the generation of electricity in Nigeria was approximately 33,489 GWh. Thermal power provided nearly 25,279 GWh (75 per cent) of this total and hydropower provided nearly 8,211 GWh (25 per cent), while generation from other energy sources was negligible (Figure 2).[9]

Figure 2. **Annual Electricity Generation by Source in Nigeria in 2019 (GWh)**

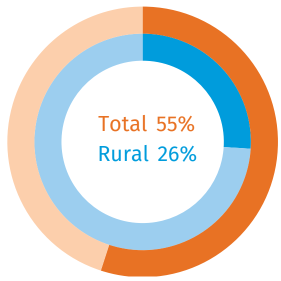


Source: NERC[9]

Although Nigeria is the largest economy in Africa, the national electrification rate stood at 60 per cent in 2018, leaving approximately 16 million households without access to electricity.[15] In 2019, nationwide electricity access declined to slightly over 55 per cent, urban electricity access stood at 84 per cent, while rural electricity access was approximately 26 per cent (Figure 3).[16] The majority of the rural population in Nigeria do not have access to electricity and shortages of electric energy production in rural areas hinder the development of the country.[12,17] In addition, the electricity supply in most parts of the country is unreliable due to frequent power outages caused by failures occurring on the main transmission grid as well as on the distribution networks, forcing consumers (both industrial and residential) to rely on diesel or petrol generators to meet their electricity needs.

The national electricity regulator is the Nigerian Electricity Regulatory Commission (NERC), an independent regulatory body established in 2005 as part of a process that effectively ushered in the privatization of electric power services in the country. The primary function of the NERC is to regulate electricity tariffs issued by both private and public generating companies. Additional responsibilities of the NERC include licensing operators, determining codes and standards, establishing customer rights and obligations and setting cost-reflective industry tariffs. Since its inception, the NERC has worked to facilitate the expansion of generating capacity and the national grid through the issuance of licences for the generation, transmission and distribution of electricity, as well as the development of codes and industry standards, market rules and a multi-year tariff structure.[18]

Figure 3. **Electricity Access Rate in Nigeria in 2019 (%)**



Source: World Bank[16]

In March 2020, the NERC initialized a transition from demand-based to cost-reflective and service-reflective electricity tariffs. Following these changes, consumer tariff rates are now based on the duration of the daily electricity service, with different service duration minimums applied to each of the five consumer classes:

- Residential (R): A consumer who uses the premises exclusively as a residence — house, flat or multi-storied house; minimum daily duration of service of 20 hours;
- Commercial (C): A consumer who uses the premises for any purpose other than exclusively as a residence or as a factory for manufacturing goods; minimum of 16 hours;
- Industrial (D): A consumer who uses the premises for manufacturing goods, including welding and ironmongery; minimum of 12 hours;
- Special (A): Consumers such as agriculture and agro-allied industries, water boards, religious houses, government and teaching hospitals, government research institutes and educational establishments; minimum of 8 hours;
- Street Lights (S): minimum of 4 hours.[18,19]

Additionally, electricity tariffs in Nigeria vary by region as well as by connection type for each consumer class. Table 1 displays residential tariffs across different regions of Nigeria in 2022. It must be noted than although the tariffs have been on a decreasing trend in recent years, they are still relatively high, as the duration of supply is limited and only a fraction of the population is connected to the grid in many areas.

Table 1. **Electricity Distribution Tariffs for Residential Users in Nigeria in 2022**

Region	*Price by connection type (NGN/kWh (USD/kWh))*				
	Lifeline	*Single-phase*	*Three-phase*	*Low-voltage maximum demand*	*High-voltage maximum demand*
Abuja	4.00 (0.010)	19.51 (0.047)		37.12 (0.089)	
Benin	4.00 (0.010)	24.49 (0.059)	26.94 (0.065)	31.69 (0.076)	
Enugu	4.00 (0.010)	20.76 (0.050)	23.01 (0.055)	32.30 (0.078)	30.93 (0.059)
Ibadan	4.00 (0.010)	20.98 (0.050)		37.53 (0.090)	
Jos	4.00 (0.010)	34.76 (0.083)		53.29 (0.128)	
Kaduna	4.00 (0.010)	19.50 (0.047)	23.01 (0.055)	30.42 (0.073)	34.71 (0.083)
Kano	4.00 (0.010)	18.60 (0.045)	24.47 (0.059)	35.24 (0.085)	
Ikeja	4.00 (0.010)	18.34 (0.044)	20.47 (0.049)	30.61 (0.073)	30.98 (0.074)
Port Harcourt	4.00 (0.010)	26.02 (0.062)		32.32 (0.078)	33.69 (0.081)
Eko	4.00 (0.010)	19.98 (0.048)	25.39 (0.061)	26.09 (0.063)	
Yola	4.00 (0.010)	22.25 (0.053)	24.36 (0.058)	44.5 (0.107)	0.00 (0.000)

Source: NERC[20]

SMALL HYDROPOWER SECTOR OVERVIEW

Hydropower in Nigeria is classified into six categories based on the range of installed capacity (Table 2). According to the national definition, small hydropower (SHP) includes plants between 1 MW and 30 MW of installed capacity.[21] In the current chapter, the national SHP definition of up to 30 MW is used for the purpose of comparing data with the *World Small Hydropower Development Report (WSHPDR) 2019*.

Table 2. **Classification of Hydropower in Nigeria**

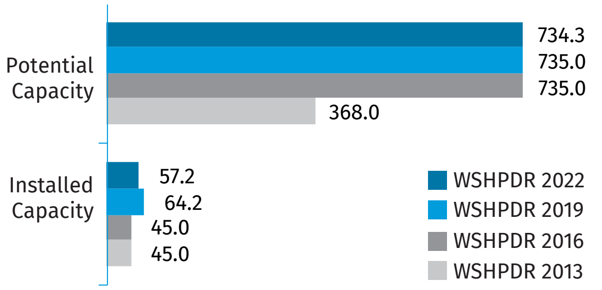
Category	*Installed capacity (MW)*
Pico	P < 0.1
Micro	0.1 ≤ P < 0.5
Mini	0.5 ≤ P < 1
Small	1 ≤ P < 30
Medium	30 ≤ P < 100
Large	P > 100

Source: Fagbohun,[12] Imo et al.[21]

SHP projects are generally considered in Nigeria to be more environmentally friendly than both large hydropower plants and power plants running on fossil fuels, because SHP projects generally do not involve significant deforestation or inundation of the surrounding area. The net cost savings resulting from the use of local materials and labour, standardized power plants and the relative ease of local development of the SHP technology make it attractive for remote and off-grid applications, while directly benefiting rural communities.[22,23] The diverse topography and abundant watercourses of Nigeria are likewise suitable for SHP.

There were 14 SHP plants up to 30 MW operating in Nigeria as of 2021, with a total installed capacity of 57.2 MW (Table 3).[12,21,22,24,25,26] All existing SHP plants are not connected to the national grid and mostly provide power to remote rural areas. The theoretical potential capacity for SHP up to 30 MW has been estimated at 3,500 MW, indicating that less than 2 per cent of the potential has been developed so far, while the economically-feasible undeveloped potential has been estimated at 734.3 MW.[12,27,28] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity decreased by nearly 11 per cent while potential capacity decreased slightly by less than 1 per cent, due to more accurate information becoming available (Figure 4).[29]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Nigeria (MW)**



Source: Fagbohun,[12] Imo et al.,[21] Muhammadu & Usman,[22] Zarma,[24] Igweonu & Joshua,[25] Onyemaechi & Charles,[26] Nkwoh,[28] *WSHPDR 2019*,[29] *WSHPDR 2013*,[30] *WSHPDR 2016*[31]

Table 3. **List of Existing Small Hydropower Plants in Nigeria**

Name	*Location*	*Capacity (MW)*
Zungeru	Niger	10.000
Oyan	Ogun	9.000
Kurra	Plateau	8.000
Gyrara Dam	Niger	6.000
Kano	Tiga	6.000
Lere I	Plateau	4.000
Lere II	Plateau	4.000
Bakalor	Sokoto	3.000
Bagel II	Plateau	2.000
Ouree	Plateau	2.000
Kwali falls	Plateau	2.000

Name	Location	Capacity (MW)
Bagel I	Plateau	1.000
Waya Dam	Bauchi	0.150
Ezioma Mgobowo	Enugu	0.030
Evoboro	Edo	0.003
	Total	**57.183**

Source: Fagbohun,[12] Imo et al,[21] Muhammadu & Usman,[22] Zarma,[24] Igweonu & Joshua,[25] Onyemaechi & Charles[26]

Over the last decade, several new SHP projects have been launched in the country (Table 4). However, their current status and stage of completion are unclear. Additionally, studies have identified 278 potential SHP sites up to 30 MW with a total potential capacity of 734.3 MW.[12] Several potential undeveloped SHP sites available for investment are listed in Table 5. According to some estimates, a total demand of 3,315 MW could be fulfilled by SHP in Nigeria by 2030, provided sufficient investment is made.[22]

Table 4. **List of Selected Ongoing Small Hydropower Projects in Nigeria**

Name	Location	Capacity (MW)	Development stage
Challawa Gorge Dam	Kano	7.00	Dam construction completed; electromechanical system yet to be installed
Ikere Gorge Iseyin	Oyo	6.00	Dam construction completed; electromechanical system yet to be installed
Annoke Ugbokpo	Benue	1.20	Dam construction completed; electromechanical system yet to be installed
Tunga Dam	Taraba	0.40	Under construction
Gurara Dam	Niger	0.03	Under Construction

Source: Onyemaechi & Charles[26]

Note: As of 2013.

Table 5. **List of Selected Potential Small Hydropower Sites in Nigeria**

Name	Location	Potential Capacity (MW)
Jada Dam	Upper Benue River	5.000
Kiri Dam	Upper Benue River	1.083
Monkin Dam	Upper Benue River	0.500
Waya Dam	Upper Benue River	0.062
Dandinkowa Dam	Upper Benue River	0.033

Source: Zarma[24]

RENEWABLE ENERGY POLICY

Nigeria is actively in the process of developing renewable energy policies and strategic documents. In 2006, the Energy Commission of Nigeria (ECN) and the United Nations Development Programme (UNDP) created the Renewable Energy Master Plan (REMP), with a subsequent review in 2012.[32] The former Ministry of Power and Steel, in collaboration with the International Centre for Energy, Environment and Development (ICEED) put together the Renewable Electricity Policy Guidelines in 2006, focusing on the use of small-scale renewable energy sources for rural electrification, and launched the Renewable Electricity Action Programme (REAP) operationalizing the guidelines the same year. The Japan International Cooperation Agency (JICA), in collaboration with the Federal Ministry of Water Resources (FMWR), put together several Hydropower Master Plans in 1993, 1995 and 2013 and in 2007 the Solar Energy Master Plan. In 2007, the Nigerian National Petroleum Corporation (NNPC) issued the National Biofuel Policy and Incentives, which established a biofuel support programme aiming at integrating the agricultural sector with the downstream petroleum sector. Finally, the National Renewable Energy and Energy Efficiency Policy (NREEEP), adopted in 2015, provides an overarching framework for the development of renewable energy sources and energy efficiency, thereby functioning as an umbrella policy for the various existing documents.[12,23,25]

With regard to hydropower development, the aforementioned legislation, programmes and frameworks aim to fulfil the following goals:

- Fully harnessing the hydropower potential available in the country for electricity generation;
- Giving particular attention to the development of mini- and micro-hydropower projects;
- The exploitation of hydropower resources shall be done in an environmentally sustainable manner;
- The active promotion of private sector and indigenous participation in hydropower development.[25]

An important overarching development that had positive impacts on the expansion of renewable energy sources in Nigeria was the 2005 Electricity Sector Reform Law. The Law allowed private operators to apply for and obtain a licence through the NERC to build and operate a power plant with an aggregate capacity greater than 1 MW. The Law additionally established the Rural Electrification Agency (REA) together with an independent Rural Electrification Fund (REF), which holds as its primary objective the full integration of renewable energy sources into the energy options available for rural electrification.[23]

In February 2018, Nigeria completed the Renewable Energy and Energy Efficiency Partnership project, which supplied 261,938 citizens with clean renewable energy. This project was implemented in partnership with the US Agency for International Development (USAID), private donors, government agencies, financial institutions and non-governmental organizations. The goal of the project was to build connections to 2.5 MW of power through off- and on-grid sources, which is expected to reduce CO_2 emissions by 4.5 million metric tons.[33]

SMALL HYDROPOWER LEGISLATION AND REGULATION

The Federal Ministry of Environment (FME) is responsible for environmental impact assessment (EIA), to be implemented in accordance with the Environmental Impact Assessment Act (Decree No. 86) of 1992 and the guidelines promulgated in 1995. All development projects are classified in one of the following three categories based on the guidelines:

- Projects requiring a full EIA;
- Projects requiring a partial EIA primarily focused on environmental impact mitigation measures and an environmental plan (although a full-scale EIA is required if a project site is adjacent to an area with special environmental and social considerations);
- Projects with "essentially favourable impacts" on the environment, for which the FME prepares a simple environmental impact statement.

Additionally, the Policy for Managing Effluents and Discharges replaces the EIA with a simplified procedure for off-grid hydropower and captive generation below 10 MW.[14]

COST OF SMALL HYDROPOWER DEVELOPMENT

The purchase price of electricity from SHP plants in Nigeria necessary to ensure project payback within a reasonable timeframe ranges between 0.03 USD/kWh and 0.06 USD/kWh, making SHP an attractive source of electricity generation. The comparative costs of different renewable energy sources in Nigeria are provided in Table 6.[25]

Table 6. **Comparative Cost of RES development in Nigeria**

Technology	*Initial capital cost (USD/kW)*
Micro-hydropower, 10-20 kW	1,000–2,400
Solar power (PV), 0.070 kW	11,200
Solar power (PV), 0.090 kW	8,400
Wind power, 0.025 kW	5,500
Wind power, 4 kW	3,900
Wind power, 10 kW	2,800

Source: Igweonu & Joshua,[25]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers faced by the SHP sector in Nigeria include:

- Inadequate policy, institutional and regulatory frameworks to stimulate demand and attract investors. Although several policies and regulatory frameworks are in place to promote renewable energy-based electricity generation, there is no definite and well-framed pathway to making these policies successful.
- High initial investment costs of SHP development relative to those for large hydropower.
- Inadequate private sector participation in SHP development. So far, the private sector is only actively involved in the importation and marketing of renewable energy components. Full participation by the private sector in all aspects of SHP development, especially in the form of investment towards local fabrication of turbines, will enhance the development of SHP.
- Limited access to relevant data. The recent unbundling of the Power Holding Company of Nigeria into different companies under the privatization programme has made the process of acquiring relevant data for SHP development challenging.
- Lack of public awareness of the potential and benefits of SHP as a viable source for electricity generation.
- Insufficient skilled labour for developing SHP projects.

The primary enablers for SHP development in the country could be defined as:

- The very significant untapped potential SHP capacity;
- The urgent need to extend electrification to many parts of the country undersupplied with electricity and beyond the reach of the current transmission and distribution networks.

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Senegal

Davy Rutajoga, International Center on Small Hydro Power (ICSHP)

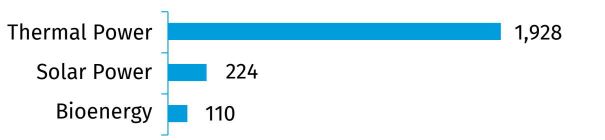
KEY FACTS

Population	16,743,930 (2020)[1]
Area	196,722 km^2 [2]
Topography	Senegal is a relatively flat country within the depression known as the Senegal-Mauritanian Basin. The north of the country presents dunes from Cap Vert to Saint-Louis. The south has muddy estuaries and includes the greener Casamance Region, which presents a more varied relief and is separated from the rest of the country by the Republic of the Gambia. The south-east is home to the Tamgué foothills, which rise up to a maximum altitude of 581 metres. The north-west is mostly a semi-desert, but the centre and much of the south, except for the forests of the Casamance, are open savannah country.[3]
Climate	Senegal has a tropical dry climate with three climate zones (coastal, Sahelian and Sudanic) and two distinct seasons: a dry season from October to May and a rainy season from June to September. The mean annual temperature is 28.6 °C, while the monthly averages in the hottest seasons can reach 35 °C. The colder months can bring temperatures as low as 14 °C, particularly in January.[4,5]
Climate Change	Between 1961 and 2010, Senegal has seen an overall increase in temperatures ranging from 0.58 °C to 1.88 °C. Decreases in precipitation were also recorded as well as irregular and unpredictable rainfall patterns throughout the country. There has been an increase in both droughts and floods in recent years and a recorded rise in sea level.[4]
Rain Pattern	The coastal climate zone, which occurs along the Atlantic coastline, experiences rainfall from June to October with an average annual rainfall of approximately 500 mm. The Sahelian climate zone, an area between the Senegal River to the north and a line running from the town of Thiès to the neighbouring Mali, experiences average precipitations of 360 mm. The Sudanic climate zone occurs in the southern half of the country and brings precipitation averages between 740 mm and 1,270 mm. The mean annual precipitation in Senegal is 713.8 mm.[4,5]
Hydrology	The main rivers in Senegal are the Senegal, Gambia and Casamance Rivers. The Senegal River, considered the most important waterway as it passes a long route through the interior of the country, flows through the mountain masses of the east, rising at the Fouta Djallon foothills and rapidly falls before reaching the Senegalese territory. The river then forms the False Delta at Dagana, supplying Lake Guier.[2]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in Senegal are thermal power and solar power, accounting for 85 per cent and 10 per cent, respectively, of the total electricity production of 2,263 GWh in 2019. Production from renewable bioenergy accounted for 110 GWh, or 5 per cent of the total production, in 2019 (Figure 1).[6]

Figure 1. **Annual Electricity Generation by Source in Senegal in 2019 (GWh)**



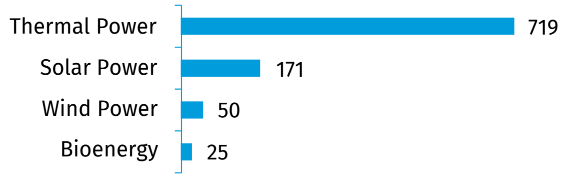
Source: IRENA[6]

The electricity sector in Senegal is overseen by the Ministry of Petroleum and Energy and regulated by the Regulatory Commission for Electricity Sector (CRSE). The CRSE works with Senelec, the national utility, and the Agency for Rural Electrification (ASER) to regulate production, supply and distribution within the country and in the regional West African Power Pool (WAPP).[7]

In Senegal, independent power producers (IPP) have a relatively strong presence and contribute greatly to electricity generation. This is a result of Law No. 98-29 of 1998 that created the ASER, which oversees public-private partnerships for the development of the electricity sector and attracts IPPs. These IPPs include the Moroccan ONE, EDF-Matforce, ENCO/ISOFOTON Maroc, the group STEG-Coselec-LCS, Kolda Energy and Electricité du RIP (EDR), all operating in rural Senegal.[8,9]

In 2020, power plants in Senegal had a combined installed capacity totalling 965 MW, of which thermal power, solar power, wind power and renewable bioenergy contributed 719 MW (or 74 per cent), 171 MW (or 18 per cent), 50 MW (or 5 per cent) and 25 MW (or 3 per cent), respectively (Figure 2).

Figure 2. **Installed Electricity Capacity by Source in Senegal in 2020 (MW)**

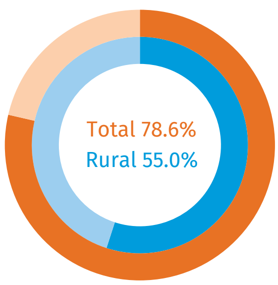


Source: IRENA[6]

Senegal is a member country of the Economic Community of West African States (ECOWAS). The ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) aims to support the development of renewable energy sources and energy action plans in the member states. Senegal is also part of the West African Power Pool (WAPP), a regional organization dedicated to fostering greater cooperation in the region's power sector and interconnection among countries to enhance energy security.[10]

Senegal has one of the highest electrification rates in Africa at almost 79 per cent in 2020, with a 55 per cent rural access rate (Figure 3).[11]

Figure 3. **Electrification Rate in Senegal in 2020 (%)**



Source: World Bank[11]

Electricity tariffs in Senegal vary depending on the provider, though not considerably. The largest provider is, by far, Senelec, which in 2020 charged tariffs ranging from 0.15 USD/kWh to 0.29 USD/kWh depending on the level of consumption. The tariffs are set by the CRSE.[9]

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) in Senegal refers to hydropower plants with a capacity of up to 10 MW. There are currently no SHP plants on the territory of Senegal and no potential sites have been officially identified due the flat topography of the country that is unfavourable for the development of SHP.

RENEWABLE ENERGY POLICY

Senegal was one of the first countries in West Africa to pass a renewable energy (RE) law, the Renewable Energy Policy Law of 2010, and is one of the most committed to strengthening institutional framework in the RE sector.[12]

The Government of Senegal launched the Energy Sector Development Policy Letter of 31 October 2012, pursuant to Act No. 2010-21 on the Renewable Energy Policy Law of 20 December 2010 and Decree No. 2011-2013 on the Implementation of the Renewable Energy Act. The decree set the conditions for the purchase and remuneration of electricity from RE sources. The Renewable Energy Law provides a legal framework for tax exemptions for the purchase of equipment necessary to develop RE production for domestic use. The law also created the foundation for a feed-in tariff (FIT) scheme.[8,13]

In order to promote and develop the RE sector through a favourable legislative and regulatory framework, the National Renewable Energy Agency (ANER) was created by Order 2013-684 and a Centre for Studies and Research into Renewable Energy was launched at the University Cheikh Anta Diop of Dakar for the purpose of conducting studies on RE potential in Senegal.[13]

The national economic and social development plan of Senegal, the Plan for an Emerging Senegal (PSE 2025), highlights the importance of RE development in the country through the goal of at least a 23 per cent share of on-grid RE in power generation by 2030. As part of the PSE 2025, a National Action Plan for Renewable Energies (PANER) was designed with specific targets for 2025, including:

- Power of 440 MW from different sources (solar photovoltaics (PV) and wind power);
- RE penetration rate of 30 per cent.[13]

In the capital city of Dakar, the Environmental Action Plan (PACTE) and the Master Plan for Urban Development of Dakar and Its Surroundings (PDU 2035) aim for a 15 per cent share of RE and a reduction of diesel share in local generation mix from 90 per cent in 2013 to 5 per cent by 2035. The City of Dakar has also finalized the Territorial Energy Climate Plan (PCET), an integrated energy and climate change development plan informing the city's short- and long-term RE roadmap as part of its commitment to the C40 Cities Leadership Programme. Through the PCET, the Government of Senegal also plans to equip over half of all municipal buildings in the capital with rooftop grid-connected solar PV by 2030.[14]

BARRIERS AND ENABLERS TO SMALL HYDROPOWER DEVELOPMENT

The development of SHP projects in Senegal is hampered mainly by:

- Flat terrain;
- Deficient infrastructure, as there is inadequate maintenance of larger hydropower plants;

- Lack of local capacity for the installation and maintenance of SHP plants;
- Limited comprehensive mapping of RE sources in key areas;
- Limited availability of hydrological data.

Enablers for SHP development in Senegal include:
- Government support for the development of RE in general;
- Strong institutional framework for RE, including large hydropower, which could be reformed to include SHP.

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Sierra Leone

International Center on Small Hydro Power (ICSHP)

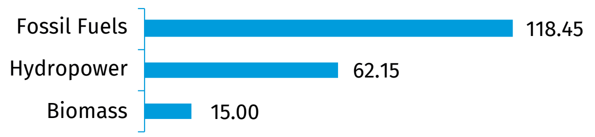
KEY FACTS

Population	8,238,175 (2022)[1]
Area	71,740 km²[2]
Topography	The western part of the country, the Sierra Leone Peninsula, is a mountainous area that slopes down to the coastal plain in the east and extends inland for 100–160 kilometres. The north-east is characterized by stretches of wooded hills that lead to a plateau region lying at an elevation of 300–610 metres. The highest point is Loma Mansa (Bintimani) at 1,948 metres. The relief is drained by a system of rivers flowing through cataracts and waterfalls. They are navigable for short distances and are ideal for hydropower development and providing water for the rural communities.[3,4]
Climate	Sierra Leone has a tropical climate, with inland areas having a temperate climate and coastal areas having a hot and humid weather. The annual temperatures average 26.5 °C. The dry season lasts from November to April, brings harmattan winds from the Sahara Desert and results in sandstorms and little precipitation. The wet season, lasting from May to October, is characterized by winds from the south-western monsoon.[3,5]
Climate Change	Sierra Leone has been experiencing increasing dry spells, which, combined with low-moisture content in the soil, affect farming production. Dry spells are often interrupted by torrential rains making the rainfall pattern irregular and harder to adapt to. The rise in sea level has also translated into frequent and severe floods, which, combined with deforestation, saturate the soil leading to catastrophic mudslides and landslides. The annual precipitation pattern has become erratic in the last 50 years, with delayed starts to the rainy season. The pre-monsoon period from April to June has come to be associated with more frequent rains and storms as well as stronger winds. The September to November period, which was characterized by rather frequent thunderstorms usually, has become calmer and drier. The harmattan has also been observed to be warmer in recent years and the average annual temperatures have increased by 0.8 °C since 1960.[4,5,6]
Rain Pattern	The coast and the mountains receive more than 5,800 mm of rainfall annually, while the rest of the country receives approximately 3,150 mm. There are three climatic belts: from the coast to 80 kilometres inland, with rainfall greater than 3,300 mm per annum; 80–190 kilometres inland, with an average annual rainfall of 2,500–3,300 mm; and from 190 kilometres inland to the border areas, with an average annual rainfall of 1,900–2,500 mm.[3,4,5]
Hydrology	The country has 12 river basins. Five are shared with Guinea and two with Liberia. The most important rivers are the Kolente (Great Scarcies), Kaba, Rokel, Pampana (Jong), Sewa, Moa and Mano. Seasonal variation affects the flow, which is lowest in April, as only 11–17 per cent of discharge occurs from December to April.[3]

ELECTRICITY SECTOR OVERVIEW

The energy sector in Sierra Leone is heavily dependent on imported petroleum, hydropower and biomass. Of the 195.6 MW of installed capacity in 2020, renewable energy accounted for 39 per cent and petroleum accounted for 61 per cent (Figure 1). The total electricity generated in the same year was 696 GWh, of which renewable energy represented 45 per cent and fossil fuel 55 per cent.[7]

Figure 1. **Installed Electricity Capacity by Source in Sierra Leone in 2020 (MW)**

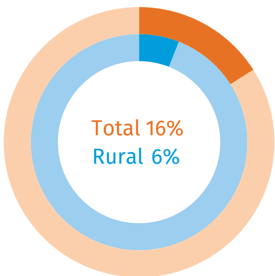


Source: AF-Mercados (IRP)[7]

There are recent projects to increase electricity supply to Sierra Leone. These include the completed Cote D'Ivoire-Liberia-Sierra Leone-Guinea (CLSLG) transmission line, which, for Sierra Leone, consists of a 225 kV power line that covers the districts of Kenema, Pujehun, Kono, Koinadugu, Tonkolili, Kambia, Bombali and Karene. There is also an Exim Bank–funded project for the construction of a 225 kV power line passing through the towns of Yiben, Fadugu, Port Loko, Waterloo, Kent, Sussex and Goderich. The United Kingdom Foreign, Commonwealth and Development Office (FCDO) and the United States Trade and Development Agency (USTDA) are funding the Rural Renewable Energy Project, aiming to bring mini-grid renewable energy connection to approximately 154 locations in Sierra Leone.[8,9,10]

Sierra Leone remains one of the countries with the lowest rates of electrification, with 84 per cent of the country lacking access to electricity in 2018.[11] The country's urban and rural electrification rates were 53 per cent and 6 per cent, respectively, in the same year (Figure 2). The rates of electrification for the main cities as of 2021 are shown in Table 1.

Figure 2. **Electrification Rate in Sierra Leone in 2018 (%)**



Source: IEA[11]

Table 1. **Electrification Rate by City in Sierra Leone in 2021**

City	*Electrification rate (%)*
Freetown	82
Bombali	26
Western Rural Area	25
Bo	18
Kenema	15
Port Loko	12
Kono	8
Bonthe	3
Tonkolili	2
Kailahun	0
Moyamba	0
Pujehun	0
Koinadugu	0
Falaba	0
Karene	0
Kambia	0

Source: Conteh et al.[12]

The electricity in Sierra Leone is generated under the responsibility of the Electricity Generation and Transmission Company (EGTC), which was founded under the National Electricity Act of 2011. The electricity is distributed and supplied by the Government-owned Electricity Distribution and Supply Authority (EDSA), founded in 2014 after the unbundling of the National Power Authority (NPA).[13]

To remedy the instability of the electricity sector in the country, in 2018 the Government, through EDSA, entered into a five-year agreement with the Turkish power ship company Karpowership to supply the capital city of Freetown with electricity. The first power ship, Karadeniz Powership Doğan Bey, was commissioned to supply 50 MW for seven months and 30 MW for five months to Freetown for a period of three years. A second power ship, Karadeniz Powership Göktay Bey, was commissioned and began operations in Cline Town Bay in 2019. Since June 2020, a new agreement signed by EDSA aims to extend the contract with Karpowerhip for five more years for a capacity of 63 MW during the dry season and 23 MW during the wet season. As of 2021, Karpowership supplied Sierra Leone with 80 per cent of its electricity needs.[14]

Electricity tariffs in Sierra Leone are established by EDSA (Table 2).

Table 2. **Average Electricity Tariffs in Sierra Leone**

Consumer type	*Units (kWh)*	*Average electricity tariff (USD/kWh)*	*GST* (USD)*	*Tariffs incl. GST (USD)*	*Service charge (USD)*
T-1 Residential – social	0–25	0.047	0.007	0.054	0.882
T-1 Residential – normal	>25	0.135	0.020	0.155	N/A
T-2 Commercial	All units	0.157	0.023	0.180	1.186
T-3 Institutions	All units	0.151	0.022	0.173	1.237
T-4 Large energy users	All units	0.159	0.024	0.183	6.353
T-5 Street lighting	All units	0.141	0.021	0.162	2.475
T-2 Welding	All units	0.160	0.024	0.184	3.324

Source: SLEWRC[15]

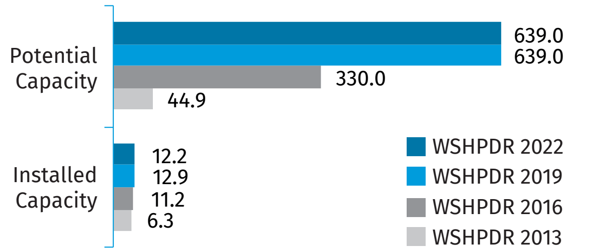
Note: * Goods and services tax (15 per cent)

Sierra Leone is a member country of the Economic Community of West African States (ECOWAS). The ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) aims to support the development of renewable energy sources and energy action plans in the member states. Sierra Leone is also part of the West African Power Pool (WAPP), a regional organization dedicated to fostering greater cooperation in the region's power sector and interconnection among countries to enhance energy security.[16]

SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in Sierra Leone follows that of the ECOWAS Small-Scale Hydropower Programme's, which defines SHP as hydropower with installed capacity of up to 30 MW.[16] For the purposes of this chapter, the up to 10 MW definition of SHP will be used. The country's installed capacity for SHP up to 10 MW stood at approximately 12 MW in 2020, coming from eight plants (Table 3).[7] According to the 2017 ECREEE report, Sierra Leone has 639 MW of theoretical potential for SHP up to 10 MW, including 140 MW of pico-, micro- and mini-hydropower and 499 MW of SHP of 1–10 MW capacity.[17] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity slightly decreased based on the available data, whereas the potential has remained unchanged (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Sierra Leone (MW)**



Source: AF-Mercados,[7] ECREEE,[17] *WSHPDR 2013*,[18] *WSHPDR 2016*,[19] *WSHPDR 2019*[20]

Note: Data for SHP up to 10 MW.

Table 3. **List of Existing Small Hydropower Plants in Sierra Leone in 2020**

Name	*Capacity (MW)*
Makeni	4.00
Goma	3.00
Charlotte	2.20
Port Loko/Bankasoka	2.20
Makali	0.50
Segbwema	0.15
Panguma	0.09
River n2	0.01
Total	**12.15**

Source: AF-Mercados[7]

There is a planned SHP plant in Sierra Leone, the Moyamba project on the Gbangbaia River, with a potential capacity of 15.4 MW (Table 4). The feasibility study was completed in 2016.[21]

Table 4. **List of Selected Planned Small Hydropower Projects in Sierra Leone**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Development stage*
Moyamba	Gbangbaia River	15.4	14.8	Feasibility study completed (2016)

Source: ECREEE[21]

RENEWABLE ENERGY POLICY

The Government of Sierra Leone has drafted a number of policies for the creation of an enabling regulatory framework for the development of off-grid renewable energy systems, including the 2009 Energy Policy and the 2016 Energy Efficiency Policy. Specifically, these policies aim to attract private sector investment in the electricity sector, ensure the financial independence and commercial viability of EDSA as well as improve the transparency, predictability and financial viability of the electricity sector.[22]

A major barrier to the penetration of off-grid renewable energy systems in Sierra Leone is the lack of financial inclusion. In 2017, approximately 80 per cent of the population did not have an account with a formal financial institution or a mobile money service provider, compared to an average of 57 per cent in Sub-Saharan Africa. As a way to increase financial inclusion in the country, the Bank of Sierra Leone launched a National Strategy for Financial Inclusion (NSFI) in 2017.[22]

Currently, the Government has several objectives regarding development and renewable energy, which are set forth in the Renewable Energy Policy of Sierra Leone and the National Renewable Energy Action Plan (NREAP) of 2015. Some of the targets include:

- Increasing installed renewable energy capacity, reaching 659 MW by 2020 and 1,229 MW by 2030;
- Increasing access to renewable energy via off-grid solutions including mini-grids;
- Increasing the number of households with solar heating systems.

In order to achieve the set renewable energy goals, the Government of Sierra Leone has been benefiting from financial assistance from the United Kingdom Foreign, Commonwealth and Development Office (FCDO) and the Government of Japan. These countries contributed an estimated USD 700,000 and USD 55,000, respectively, in 2019, for the development of mini-grid electricity systems in Sierra Leone. The United Nations Office for Project Services (UNOPS) contributed to the country's efforts in relation to renewable energy in the form of grants, with an aim of accelerating demand and improving rural energy-reliant economic opportunities and productive use of equipment and services.[23]

Sierra Leone, as a member country of the ECOWAS, is committed to achieving universal electricity access by 2025 through the ECOWAS Regional Renewable Energy Policy for the period of 2015–2030. Under the Sustainable Energy for All (SEforAll) Country Action Agenda, the Government of Sierra Leone also aims to reach a 10 per cent share of the population with access to electricity through off-grid systems powered by renewable energy by 2030.[22]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Precipitation variability is expected to increase in Sierra Leone as a consequence of climate warming. As SHP plants in the country are mostly without seasonal storage possibilities, the down-times of the plants are expected to increase due to extended dry spells. Furthermore, natural hazards are likely to increase with climate change and therefore floods, rock falls and landslides will negatively affect SHP plants.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

SHP development in Sierra Leone is hindered by:

- Funding: There is a lack of sufficient government funding for SHP development;
- Capacity building: There are not enough higher learning institutions in Sierra Leone that focus on teaching the skills necessary to operate and maintain SHP plants. There is also a lack of hydrology departments at local universities which translates into a lack of sufficient local technical experts;
- Manufacturing: All equipment necessary for the operation of an SHP plant needs to be imported as there are no local manufacturers;
- Electricity tariffs: The high electricity tariffs in the country deter private investors;
- Demand: There is low demand for electricity in the country as it suffers from a lack of sufficient financial inclusion for its population. Most citizens would be unable to afford the high electricity tariffs and are not registered with any formal financial institution.[22]

SHP development in Sierra Leone is enabled by:

- External assistance: As solar power development benefits from financial support from the international donors, this is an encouraging sign for future endeavours into the overall renewable energy sector;
- Potential: Sierra Leone has considerable hydropower potential;
- Openness to foreign investment: The country is open to foreign investment for the development of the energy sector.[22,24]

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Togo

Davy Rutajoga, International Center on Small Hydro Power (ICSHP)

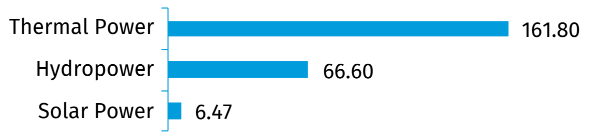
KEY FACTS

Population	8,278,737 (2020)[1]
Area	56,600 km^2 [2]
Topography	The topography of Togo consists of gently rolling hills, shallow valleys and two large alluvial plains. The Atakora Mountain Range cuts through the central part of country with natural forests and savannah landscapes. The northern part of the country, known as the Dry Sudanian Savannah, is home to the Oti River as well as a large national park. The southern regions are characterized by patchworks of cropland and savannahs. The coastal plains, or the fluvial-lagoon zone, is characterized by swamps and lagoons.[3]
Climate	Togo has a tropical climate, with two rainy seasons in the south and one in the north. In the humid south, the rainy seasons occur from mid-April through June and again from mid-September through October. In the north, the rainy season occurs from June to the end of September and the rest of the year enjoys the warm and dry harmattan (dusty wind). Mean annual temperatures in the north vary between 17 °C and 41 °C, while the south is more stable with an average annual temperature of 27 °C.[4,5]
Climate Change	Togo is affected by global warming. The mean annual temperature has increased by 1.1 °C since 1960, at an average rate of 0.24 °C per decade. The number of hot days between 1960 and 2003 has increased by 16 per cent and heatwaves have become more common. Precipitation in Togo has been decreasing at an average of 2.4 per cent per decade and no increase in heavy rainfall events have been observed.[5]
Rain Pattern	The southern coastal zone receives approximately 890 mm of annual precipitation and is the driest region. The highest amount of precipitation in the country, 1,800 mm, is received by the south-western region. In the north, precipitation averages 1,150 mm in the rainy season. The mean annual precipitation in Togo is 1,176.5 mm.[4,5]
Hydrology	Togo is endowed with many lagoons, the largest of which is Lake Togo which is also the country's largest body of inland water. More than half the length of the country is traversed by the Mono River, which flows from north to south before flowing into the Gulf of Guinea. The torrential river's intake fluctuates greatly, from an annual average of 99.6 m^3/s to 4.8 m^3/s in the dry season. The Oti River, in the north, drains into the Volta River, which flows to the north-west.[6]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in Togo are thermal power and hydropower. In 2019, thermal power accounted for 67 per cent of total production, which amounted to 647 GWh, and hydropower accounted for almost 32 per cent. Production from solar power plants accounted for 9 GWh, or approximately 1 per cent of the total electricity produced (Figure 1).[7]

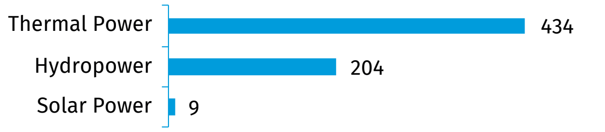
Figure 1. **Annual Electricity Generation by Source in Togo in 2019 (GWh)**



Source: IRENA[7]

In Togo, electricity is supplied mainly through the interconnected Electricity Community of Benin (CEB) and the local power system of the state-owned utility Electricity Energy Company of Togo (CEET). CEB consists of a 20 MW gas turbine in Lomé and a 65 MW hydropower plant in Nangbeto for a combined installed capacity of 85 MW. CEET owns a system of 143.4 MW of installed capacity, including a 1.6 MW hydropower plant in Kpimé and 100 MW (LFO, HFO, gas) of capacity owned by the CEET and exploited by the independent power producer (IPP) Contour Global Togo S.A under a licence. The isolated grid contributes an additional 6.47 MW of installed solar capacity. The total installed electricity capacity in 2020 was thus 234.87 MW, of which thermal power, hydropower and solar power accounted for approximately 69 per cent, 28 per cent and 3 per cent, respectively (Figure 2).[8]

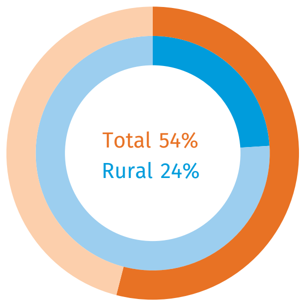
Figure 2. **Installed Electricity Capacity by Source in Togo in 2020 (MW)**



Source: ARSE[8]

In 2020, the total electrification rate in Togo was 54 per cent, with 24 per cent rural access (Figure 3).[9,10]

Figure 3. **Electrification Rate in Togo in 2020 (%)**



Source: World Bank[9,10]

Table 1. **Electricity Consumption by Sources in Togo in 2020**

Consumer category	*Electricity consumed (%)*
Commercial and industrial sector	57.4
Residential sector	32.6
Administration and public Services	10.0

Source: ARSE[8]

In Togo, the electricity sector is regulated by the Regulation Authority of the Electricity Sector (ARSE), which is also responsible for advising the Ministry of Mines and Energy on electricity tariffs, among other duties. Since 2011, the electricity tariffs on the Togolese territory are fixed through the ministerial decree No. 019/MME/MEF/MCDAT/MPR-PDAT/MCPSP of 2010. In 2020, the tariffs ranged from 0.17 USD/kWh to 0.20 USD/kWh (Table 2).[8]

Table 2. **Electricity Tariffs in Togo in 2020**

Customer category	*Tariff, incl. taxes (USD/kWh)*
Low voltage	0.20
Medium voltage	0.17
High voltage	0.19

Source: ARSE[8]

CEET is the Government-owned utility responsible for the distribution and transmission of electricity produced in Togo both through its own power plants, power plants exploited by IPPs and shared plants with CEB. CEB is a bi-national entity established in 1968 to provide generation and transmission for both Togo and Benin and had, until 2003, a monopoly on the production and distribution of electricity for both countries.[8]

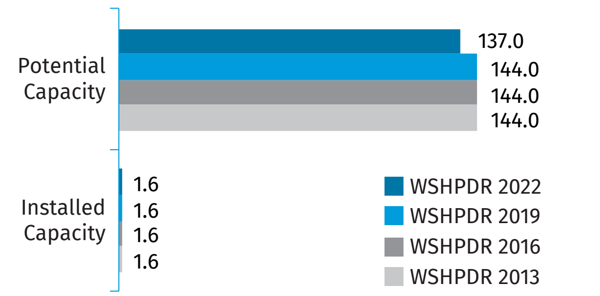
In addition to being half of the interconnected Benin–Togo grid, Togo is also a member of the Economic Community of West African States (ECOWAS) energy framework and the West Africa Power Pool (WAPP).[11]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in Togo. For the purpose of this chapter, SHP will include hydropower plants with an installed capacity of up to 10 MW. It should be noted that in the ECOWAS region, which Togo is part of, many countries use the ECOWAS definition of 1 MW to 30 MW of installed capacity for SHP.

There is one SHP plant in Togo, located in Kpimé, with an installed capacity of 1.6 MW. The identified SHP potential is approximately 137 MW. This identified potential differs from the potential reported in the *World Small Hydropower Development Report (WSHPDR) 2019* due to later studies conducted by the Government of Togo as indicated in the Baseline Report on Existing and Potential Small-Scale hydropower systems in the ECOWAS Region.[12] At the same time, the installed SHP capacity remained unchanged (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Togo (MW)**



Source: ECREEE,[12] *WSHPDR 2013*,[13] *WSHPDR 2016*,[14] *WSHPDR 2019*[15]

The Baseline Report on Existing and Potential Small-Scale Hydropower Systems in the ECOWAS Region was prepared by the ECOWAS for Renewable Energy and Energy Efficiency (ECREEE) in cooperation with the United Nations Industrial Development Organization (UNIDO), the Energy Sector Management Assistance Programme (ESMAP) and the Government of Liberia. The report explored the SHP potential of ECOWAS member-states and highlighted the SHP potential of Togo, under both the ECOWAS definition of SHP (up to 30 MW) and the international definition (up to 10 MW). The former definition produced an SHP potential of 206 MW and the latter 137 MW.[12]

There are numerous rivers in Togo and the Government has identified seven sites for the development of SHP with a combined potential installed capacity of 40 MW (Table 3).[16]

Table 3. **List of Selected Planned Small Hydropower Projects in Togo**

Site Name	*Capacity (MW)*
Danyi-Konda	10
Kpéssi	8
Tomégbé Akloa	8
Baghan	6
Landa-Pozanda	4
Amou Oblo	2
Glei	2

Source: Kansongue et al.[16]

RENEWABLE ENERGY POLICY

As a member of ECOWAS, Togo adopted the National Renewable Energy Policy (NREP) and the National Energy Efficiency Policy (NEEP) that all 15 member-states adopted in 2012. In 2015, The Government of Togo combined the NREP and NEEP for a cohesive National Renewable Energy Action Plan (NREAP 2015–2020–2030), which outlines the legal framework for electricity generation from renewable energy sources, both for own and commercial use. The NREAP addresses all sources of renewable energy, including wind power, solar power, thermal power, tidal power and hydropower and defines incentives for developers of renewable energy projects, such as tax incentives. The policy was developed by the Ministry of Mines and Energy in cooperation with CEET, the Togolese Rural Electrification and Renewable Energy Agency (AT2ER), ARSE, ECREEE, the German Agency for International Cooperation (GIZ) and the Governments of Austria and Spain.[17]

In the NREAP, the Government of Togo has several objectives regarding the development of renewable energy. Some of the targets include:

- Develop solar power capacity and increase its share in the final energy consumption to 10 per cent by 2030;
- Develop SHP in rural areas and ensure minimal environmental impact from SHP construction and maintenance;
- Attract private sector investment in hydropower;
- Develop bioenergy and promote consumption, particularly in rural areas, as an alternative source of energy;
- Develop a comprehensive database on renewable energy potential in Togo.[17]

The targets set in the NREAP were formulated to fulfil the goals of universal electrification and increase in installed renewable energy capacity to 364 MW by 2030. In addition to the specific targets, the Government of Togo aims to promote education and awareness of environmental protection and the importance of renewable energy. The Government of Togo also aims to involve local populations in all aspects of renewable energy development, including rural population involvement in the construction and development of SHP.[17]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP plants are regulated by the same legislation as larger hydropower projects. The main legislation and regulation documents in Togo concerning hydropower projects are:

- Decree No. 63-12 (1963) on the creation of the Electricity Energy Company of Togo;
- Law No. 2000-012 (2000) on the organization and function of ARSE;
- Decree No. 2019-021 (2019) that sets the licensing for production, transmission and commercialization of renewable energy.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Precipitation variability is expected to increase in Togo as a consequence of climate warming. As the only SHP plant in the country is mostly without seasonal storage possibilities, the down-times of the plant are increasing due to extended dry spells. Furthermore, natural hazards are likely to increase with climate change and, therefore, floods, rock falls and landslides will negatively affect existing and prospective SHP plants.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The development of SHP in Togo is mainly hampered by:

- Non-liberalized energy sector might deter prospective investors;
- Lack of sufficient and relevant rules and regulations within the energy sector such as standardized power purchase agreements and power purchase tariffs;
- Higher initial costs for hydropower investment than diesel generators;
- Lack of sufficient international funding for SHP driven by the lack of successful SHP projects that would inspire confidence in investors;
- Lack of manufacturing of equipment essential for SHP construction and maintenance in the country.

Enablers for SHP development in Togo include:

- Specific mention of SHP and its importance for rural electrification in national renewable energy strategy documents such as NREP and NREE;
- The commitment by the Government to exploit the country's SHP potential. Plans to build SHP plants at Danyi-Konda, Baghan and Landa-Pozanda were in mo-

tion as of 2022;
- Significant potential for SHP development due to numerous rivers found in the country;
- Plans to promote private sector investment in SHP as outlined in the country's national renewable energy strategy.

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2. Americas

2.1. Caribbean

Countries: Cuba, Dominica, Dominican Republic, Grenada, Guadeloupe, Haiti, Jamaica, Puerto Rico, Saint Lucia, Saint Vincent and the Grenadines

INTRODUCTION TO THE REGION

The electricity sectors of countries in the Caribbean are heavily reliant on thermal power for electricity generation, with renewable energy sources (RES) playing a supplementary role. Compared to other countries in the region, both the Dominican Republic and Guadeloupe have a highly diversified energy mix, although fossil fuels still predominate. Alongside wind power, solar power and hydropower, RES in the region are represented by biomass and geothermal power plants.

The role of hydropower in the region is limited due to environmental and economic factors. Only Cuba, the Dominican Republic and Haiti employ large hydropower plants, while Grenada and Saint Lucia have no hydropower capacity of any kind. In other countries in the region, all existing hydropower capacities are represented by small hydropower (SHP).

Access to electricity is at or near 100 per cent across most countries in the region with the exception of Haiti. However, seasonal extreme weather in the form of hurricanes and associated floods frequently interfere with power grids and plant infrastructure across the region, causing major disruptions to electricity access. Earthquakes have also caused widespread damage to electricity infrastructure, particularly in Haiti and Puerto Rico.

The role of the state in the electricity sectors of countries in the Caribbean varies significantly. At one end, the electricity sector of Cuba is fully state-owned. In Guadeloupe the sector is dominated by a French company where the Government of France has a controlling stake. In Saint Vincent and the Grenadines, a state-owned company operates the electricity sector across most of the country with the exception of one island, and the electricity sector of Haiti is also dominated by a state-owned company. In Puerto Rico, a state-owned company controls the largest share of generation assets, while transmission and distribution have recently been privatized. In the Dominican Republic, the electricity sector has a significant private sector and state involvement, although state-owned entities control the transmission grid and all hydropower assets. In Dominica, Grenada, Saint Lucia and Jamaica, the electricity sectors have been largely privatized.

An overview of the electricity sectors of the countries in the region is provided in Table 1.

Table 1. **Overview of the Caribbean**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Cuba	11	100	100	6,508	20,700	64	125
Dominica	0.1	100	100	27	97	7	19
Dominican Republic	10	100	98	4,921	18,688	623	1,245
Grenada	0.1	95	N/A	52	223	0	0
Guadeloupe	0.4	100	100	556	1,689	11	25
Haiti	11	45	1	294	2,199	61	N/A
Jamaica	3	94	91	1,168	4,430	31	155
Puerto Rico	3	100	100	5,839	16	N/A	N/A
Saint Lucia	0.2	99	N/A	92	368	0	0
Saint Vincent and the Grenadines	0.1	100	100	54	151	6	22
Total	-	-	-	**19,511**	-	**802**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the WSHPDR 2022; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The most commonly-used official definition of SHP in the Caribbean is up to 10 MW, and is adhered to by Dominica, the Dominican Republic, Guadeloupe, and Saint Vincent and the Grenadines. In other countries of the Caribbean, no official SHP definition exists. In Jamaica, which lacks an official definition of SHP, the up to 10 MW definition is commonly used by industry professionals, while in Cuba, the up to 5 MW definition established by the Latin American Organization of Energy (OLADE) is used on an unofficial basis.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in the Caribbean (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Cuba	N/A	N/A	N/A	21.0	77.0
Dominica	Up to 10 MW	6.6	N/A	6.6	6.6*
Dominican Republic	Up to 10 MW	59.7	N/A	59.7	59.7*
Grenada	N/A	N/A	N/A	0.0	7.0
Guadeloupe	Up to 10 MW	11.6	33.0	**11.6**	33.0
Haiti	N/A	N/A	N/A	6.8	37.6
Jamaica	N/A	N/A	N/A	30.6	76.2
Puerto Rico	N/A	N/A	N/A	39.3	43.9
Saint Lucia	N/A	N/A	N/A	0.0	2.7
Saint Vincent and the Grenadines	Up to 10 MW	5.7	7.5	5.7	7.5
Total	-	-	-	**181.4**	**351.1**

Source: *WSHPDR 2022*[1]

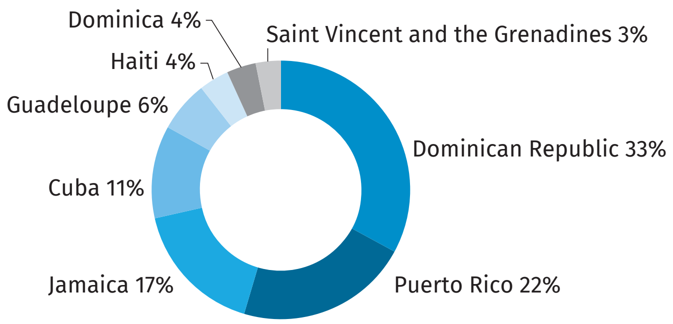
Note: *Based on installed capacity.

The total installed capacity of SHP of up to 10 MW in the Caribbean is 181.4 MW, while estimated potential capacity is 351.1 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity increased by 2 per cent, largely due to a nearly two-fold increase in the installed SHP capacity of Jamaica. Meanwhile, the installed capacities of several countries including Cuba, Haiti, Puerto Rico, and Saint Vincent and the Grenadines have been revised downwards on the basis of more accurate data. The total potential SHP capacity of the region increased by 18 per cent as a result of updated feasibility studies of potential sites as well as a reassessment of available data.

SHP fills an important niche in the energy mix of the Caribbean region, in part because the geographical and hydrological characteristics of many island countries and the importance of tourism in the region put constraints on the use of large hydropower. SHP accounts for all installed hydropower capacity in Dominica, Guadeloupe, Jamaica, Puerto Rico, and Saint Vincent and the Grenadines. In Cuba approximately a third of all installed hydropower capacity consists of SHP. At the same time, recent development in the SHP sector in the Caribbean has been very limited and further SHP development also faces significant barriers. A major reason for this is the high variability in rainfall and runoff typical for the region and the susceptibility of SHP to extreme weather events, and the consequent focus of many Caribbean countries on other RES.

The national share of regional installed capacity for SHP of up to 10 MW by country is displayed in Figure 1, while the share of total SHP potential utilized by countries in the region is displayed in Figure 2.

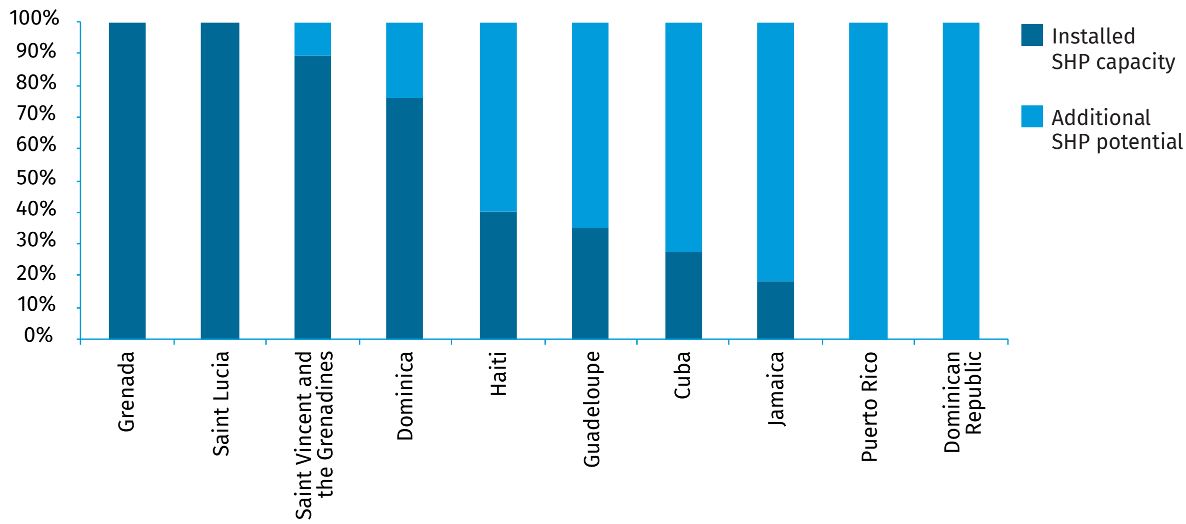
Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in the Caribbean (%)**



Source: *WSHPDR 2022*[1]

Note: Saint Lucia and Grenada not included due to lack of SHP.

Figure 2. **Utilized Small Hydropower Potential up to 10 MW by Country in the Caribbean (%)**



Source: *WSHPDR 2022*[1]

Note: No estimate of potential capacity is available for Dominica and the Dominican Republic, therefore SHP potential in these countries is assumed to be fully utilized.

Cuba has an installed capacity of 21 MW for SHP up to 10 MW, while potential capacity is estimated at 77 MW, indicating that 27 per cent has been developed. Cuba has over 170 SHP plants, of which 32 are currently non-operational due to water supply issues or disrepair. The most recent new SHP plant was commissioned in 2018, while another plant was refurbished in 2019. There were two additional SHP projects under construction as of 2021.

There are three SHP plants of up to 10 MW in **Dominica**, with a total installed capacity of 6.64 MW. The potential capacity of Dominica has not been assessed, so all known capacity is fully developed. One of the SHP plants in the country has been out of operation since 2017 as a result of hurricane damage, and the bidding process for its rehabilitation was launched in early 2022.

The installed capacity of SHP of up to 10 MW in the **Dominican Republic** is 59.7 MW provided by 16 state-owned SHP plants equipped with 22 individual power blocks, and 60 community-owned micro-hydropower plants. There is no reliable estimate of SHP potential in the country, thus, all known potential is considered fully developed. Recent SHP development in the country has been mainly carried out with the support of the Global Environmental Facility (GEF) Small Grants Programme and has focused on the construction of micro-scale plants for the benefit of rural communities. Ten additional micro-scale SHP projects are under construction.

Grenada has no hydropower capacity of any kind. The potential capacity of SHP up to 10 MW is estimated at 7 MW, although the estimate is based on a study conducted in 1981. Several SHP projects have been initiated in recent years but have not been completed and their current status is unknown.

Guadeloupe has a total installed capacity of 11.6 MW for SHP of up to 10 MW, provided by 16 plants. The potential SHP capacity is estimated at 33 MW, indicating that 35 per cent has been developed. However, the development of remaining untapped potential capacities is constrained by environmental considerations and the location of many potential sites inside protected areas. No new SHP construction has taken place in the country since 2016.

The installed capacity of SHP up to 10 MW in **Haiti** is 6.81 MW, provided by eight plants, while potential capacity is estimated at 37.6 MW, indicating that 18 per cent has been developed. No new SHP construction has taken place in the country in recent years and installed capacity has gradually decreased due to ageing equipment and lack of maintenance. Thirty-six potential SHP sites have been identified in the country.

Jamaica has an installed capacity of 30.6 MW for SHP of up to 10 MW, provided by eight SHP plants. The potential capacity for SHP of up to 10 MW is estimated at 76.2 MW, indicating that 40 per cent has been developed. The country's SHP fleet is fairly old and no new additions have been made since 2014, with the recent reported increase in installed capacity being a result of the inclusion of previously excluded plants. Thirteen potential SHP sites have been identified and the country has explicitly adopted a policy of exploring options for SHP construction at locations with the potential to host large hydropower plants.

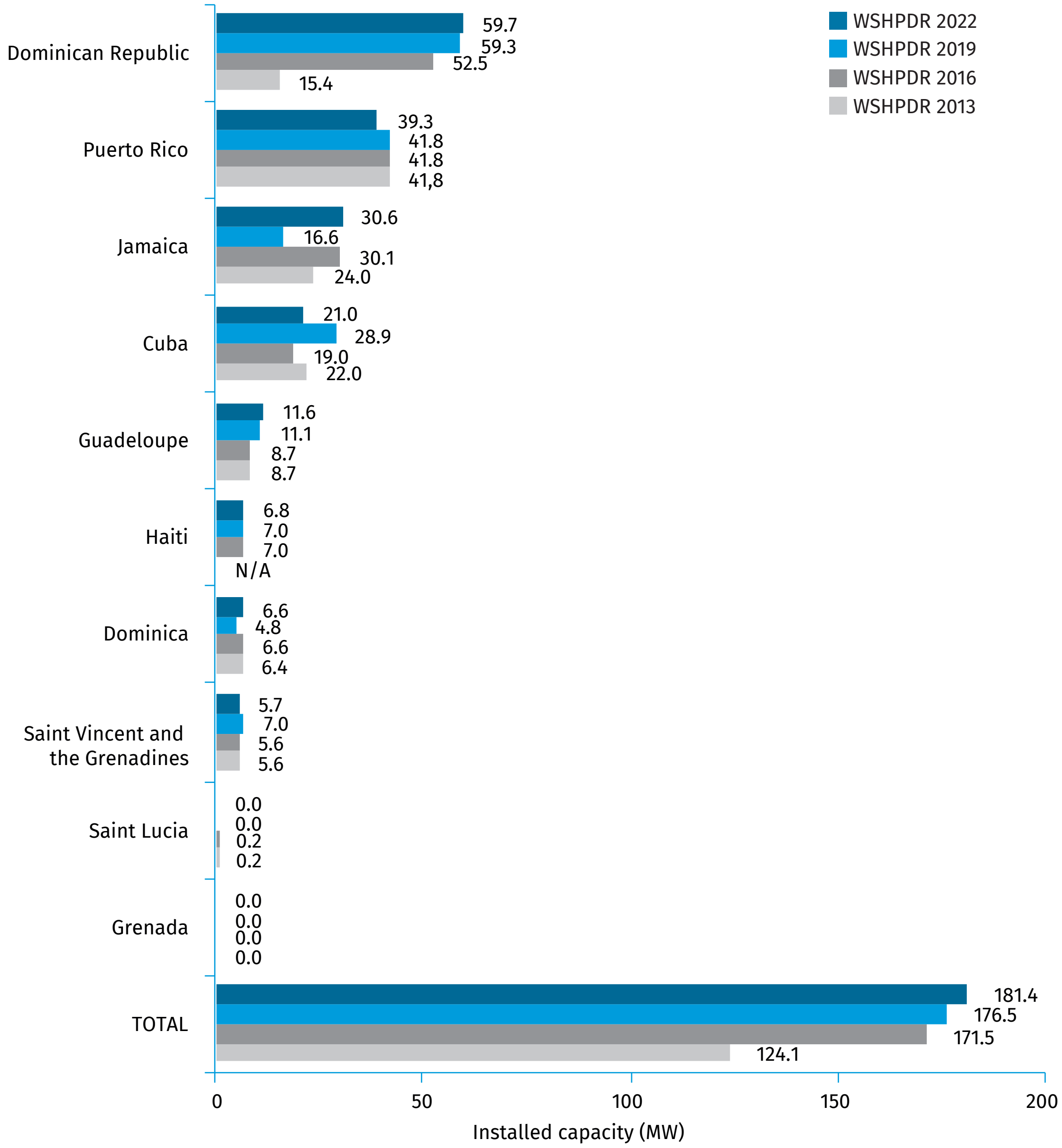
The installed capacity of SHP of up to 10 MW in **Puerto Rico** is 39.3 MW, while potential is estimated at 43.9 MW, indicating that 89 per cent has been developed. There are seven operational SHP plants in the country, although with four of these plants inactive as of 2021, the available capacity has been reduced to 23.8 MW. The main potential opportunities for further SHP development are in micro-scale hydropower projects, as other potential hydropower sites have been largely developed.

Saint Lucia has no hydropower capacity of any kind, as the country's only formerly-operational mini-hydropower plant is in a state of severe disrepair following damage from extreme weather. A potential capacity of 2.68 MW has been identified in previous studies, but there are no ongoing SHP projects in the country or any specific plans for the development of the SHP sector.

In **Saint Vincent and the Grenadines**, the installed capacity of SHP of up to 10 MW is 5.7 MW, while estimated potential capacity is 7.5 MW, indicating that 76 per cent has been developed. There are three SHP plants in the country, but their available capacity fluctuates considerably during the dry season. Refurbishment of two plants was carried out in 2016 and 2018. There are proposals for the construction of an additional SHP plant of 1.2 MW, but no concrete progress has been made.

Changes in the installed SHP capacities of the countries in the region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower up to 10 MW from *WSHPDR 2013* to *WSHPDR 2022* by Country in the Caribbean (MW)**



Source: *WSHPDR 2022,*[1] *WSHPDR 2013,*[2] *WSHPDR 2016,*[3] *WSHPDR 2019*[4]

Climate Change and Small Hydropower

The region experiences increased winter precipitation and decreased summer precipitation during the El Niño Southern Oscillation (ENSO) phase. These seasonal differences are expected to become even more pronounced as a result of climate change. The increase in frequency and intensity of extreme events exposes SHP infrastructure to damage.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The barriers to SHP development in **Cuba** include a lack of technical capacity in planning SHP projects and the manufacture of necessary components, limited financial resources and low utilization of existing capacities due to environmental limitations. However, a substantial share of the country's SHP potential remains untapped and government policies are supportive of development in the sector, particularly with regard to foreign investment.

The main barriers to SHP development in **Dominica** include a lack of incentives, a lack of data on SHP potential, issues with land acquisition from private owners and limitations on hydropower development in general due to the importance of eco-tourism in the country. Additionally, the Government has been exploring geothermal power as a prospective RES and has shown comparatively little interest in additional SHP development. However, geothermal power projects are considered to have a higher development cost relative to SHP and it is possible that SHP development will be prioritized again in the future, given the country's experience with this form of renewable energy.

SHP development in the **Dominican Republic** faces a number of challenges including increasing impacts from climate change, which affect water supply and cause damage to SHP infrastructure, a lack of data on SHP potential, lengthy administrative procedures and lack of private sector engagement. However, some studies on the potential of specific SHP sites are available. The SHP sector in the country is well-organized and can lean on decades of experience and local expertise, as well as take advantage of established international financing opportunities. The active development of micro-scale hydropower is expected to continue into the foreseeable future.

In **Grenada**, the lack of interest in SHP on the part of the Government is one of the main barriers to SHP development in the country, along with the lack of up-to-date studies of SHP potential. However, the untapped SHP potential could serve as an additional source of renewable energy to meet the country's declared clean energy goals and reduce dependence on fossil fuels.

The main obstacle to SHP development in **Guadeloupe** are the environmental restrictions that constrain the implementation of additional projects. The country has consequently focused on the development of other RES, in particular solar power, wind power and geothermal power. One possible avenue for further SHP development in the country that would avoid environmental impacts is the optimization of exiting SHP capacities.

SHP development in **Haiti** is hampered by a lack of a legal framework for private investment in the energy sector as well as a lack of coordination between government agencies and ministries, in addition to a lack of funds and limited reach of the country's transmission grid. However, much of the country's identified SHP potential remains untapped and represents an important potential source for electricity generation in a country with the region's lowest rate of electricity access.

Barriers to SHP development in **Jamaica** include the high cost and perceived complexity of construction, institutional barriers and hydrological variability. At the same time, the country possesses considerable untapped SHP potential and the Government's interest in SHP as opposed to large hydropower is a potential driver of future SHP development, both in terms of new construction and modernization of existing capacities.

The main barrier to further SHP development in **Puerto Rico** is the high degree of utilization of the country's existing potential SHP capacities, leaving few remaining undeveloped sites. Severe weather and water shortages are also important barriers. The main opportunities for SHP development in the country lie in micro-scale projects and the refurbishment of existing SHP plants, which has been identified as a priority direction by a government study in 2021. An additional enabler is the availability of support for RES in the form of subsidies.

Barriers to SHP development in **Saint Lucia** include the extremely limited SHP potential and the lack of funding opportunities specifically aimed at SHP projects. However, SHP could serve as an additional source of renewable energy and reduce the country's dependence on fossil fuels if efforts were directed at repairing the existing damaged mini-hydropower plant and develop identified potential sites.

The main barrier to SHP development in **Saint Vincent and the Grenadines** is the variability of river flow throughout the year that complicates the implementation of new SHP projects and also reduces the available capacity of existing plants. Very little SHP potential exists on the country's smaller islands and plans for the development of RES have focused on solar power and geothermal power. At the same time, all RES projects including SHP have access to feed-in tariffs (FITs) and financing for renewable energy development in the country is Available at international institutions including the GEF, the World Bank, the International Renewable Energy Agency and others.

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Cuba

Leonardo Peña Pupo, Universidad de Oriente; Ernesto Yoel Fariñas Wong, Universidad Central “Marta Abreu” de las Villas

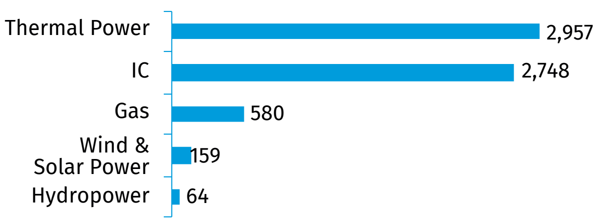
KEY FACTS

Population	11,193,470 (2019)[1]
Area	109,884.01 km^2 [2]
Topography	Approximately a quarter of the territory of Cuba is mountainous with hills dotted across the island, alternating with plains, and four main mountain ranges: the Guamuhaya in the centre (also known as mountains of the Escambray), the Guaniguanico in the west, the Nipe-Sagua-Baracoa in the north-east and the Maestra in the south-east. The Maestra is the largest mountain range and home to Pico Real del Turquino, the country’s highest peak at 1,974 metres.[2]
Climate	The climate is semi-tropical or temperate, except in the mountains. The average minimum temperature is 21 °C and the average maximum is 30 °C. The average relative humidity is 79 per cent. Coas tal areas are relatively cooler due to trade winds and sea breezes. The eastern coast is often hit by hurricanes from June to November.[3,4]
Climate Change	Droughts are common in the region of Eastern Cuba. However, due to climate change effects, the western and central regions have also started to be heavily affected by droughts.[3,4]
Rain Pattern	The rainy season in Cuba lasts from May to October. The average annual precipitation is 1,444 mm, with the mountainous areas on average receiving more than 1,800 mm a year and most of the lowland regions ranging from 900 to 1,400 mm. The area around Guantanamo Bay in the south-east receives less than 650 mm of precipitation a year.[3,4]
Hydrology	The topography and climate of the island result in short rivers with reduced flows. The longest river is the Cauto (249 km long), flowing westwards north of the Maestra. Other major rivers include the Sagua la Grande, the Zaza, the Caonao and the San Pedro. The Toa River (116,2 km), located in the provinces of Holguín and Guantanamo, has the largest volume of flow in the country.[3,4]

ELECTRICITY SECTOR OVERVIEW

In 2019, annual electricity generation in Cuba was approximately 20,700 GWh (Figure 1). Fossil fuel-based thermal power plants contributed approximately 77 per cent, including gas-powered turbines and other thermal power plants from industries (mainly biomass from the sugar cane industry). Grid-connected internal combustion (IC) generators contributed 21 per cent, while hydropower and other renewable energy sources (including wind and solar power) contributed slightly less than 2 per cent combined. Total renewable electricity in 2019 amounted to 894 GWh (4 per cent), including 519 GWh from biomass.[5]

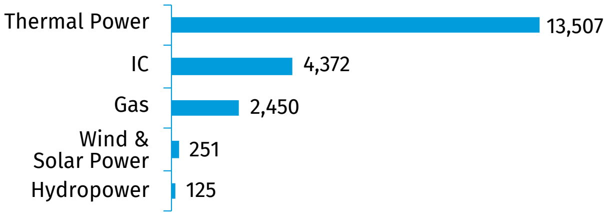
Figure 1. **Annual Electricity Generation by Source in Cuba in 2019 (GWh)**



Source: ONEI[5]

In 2019, installed capacity totalled 6,507.8 MW, with approximately 46 per cent from thermal power plants, including 7 per cent from generators operated by the Ministry of Energy and Mines and the Group of Sugar Industries (AZCUBA). IC power generators contributed 42 per cent, 9 per cent was from gas turbines and 2 per cent from solar photovoltaics (PV) and wind power. Only 1 per cent of installed capacity was from hydropower (Figure 2).[5]

Figure 2. **Installed Electricity Capacity by Source in Cuba in 2019 (MW)**



Source: ONEI[5]

Cuba achieved 100 per cent electrification rate in 2018.[5] Total electricity consumption reached 20,703.2 GWh in 2019, with the residential and public sectors having consumed approximately 45 and 39 per cent, respectively. The gross generation index stood at 1.8 MWh per citizen. Losses amounted to approximately 16 per cent.[5]

The electricity sector in Cuba is fully public, owned by the Electric Union of Cuba (UNE). UNE is part of the Ministry of Energy and Mines (MINEM) and is the main entity responsible for the generation, transmission and distribution of electricity in the country, with the exception of the electricity generated by sugar cane biomass, which is owned by AZCUBA. The National Institute for Hydraulic Resources (INRH) is the regulatory authority responsible for the management of water resources. However, hydropower plants are owned by UNE, via a subsidiary, the Renewable Energy Sources Company (EMFRE). Water use for hydropower generation is subordinated to irrigation and population supply. Furthermore, reservoirs are not built exclusively for electricity production.[5,6,7]

Since 2005, the electricity sector of Cuba has undergone numerous reforms with a new energy development strategy known as the Energy Revolution started in 2006. Notably, the key features of the strategy include the promotion of distributed generation, rehabilitation of electric grids, energy saving and energy education and the promotion of renewable energy sources. The focus of the National Electric System (SEN) has been placed on increasing the use of renewable energy, liquid natural gas and biomass to gradually decrease the share of oil-based thermal power plants.[4,5]

In recent years, the share of combined cycle and IC generators in the country's energy mix has experienced a rise as a result of the efforts to move away from a concentrated system composed of large thermal power plants towards a distributed generation system. The reduced concentration of the country's generation capacity in large thermal power plants has also mitigated the risks posed to the system by hurricane damage. Furthermore, the efforts in achieving a distributed system reduced the consumption of fossil fuels as the energy efficiency of IC generators is higher than that of large thermal power plants.[4] The specific fuel consumption of all power plants in 2018 was 257.7 grams of conventional fuel per kilowatt-hour (g/kWh), however thermal fuel consumption stood at 276.1 g/kWh.[5]

Since January 2021, new electricity tariffs have been introduced for households and the non-residential sector, as part of the country's ongoing process of monetary unification. In particular, electricity tariffs have increased exponentially, with tariffs depending on monthly consumption (Table 1).[8,9] The new average price is approximately three times higher than in the old tariff system, under which 97.8 per cent of the customers consumed up to 500 kWh. The increase of electricity tariffs is directly related to the devaluation of the Cuban Peso, given that the electricity supply of Cuba is heavily dependent on energy imports.[8]

Table 1. **Electricity Tariffs in Cuba in 2021**

Consumption (kWh)	*Price (CUP/kWh (USD/kWh))*	*Consumption (kWh)*	*Price (CUP/kWh (USD/kWh))*
0–100	0.33 (0.01)	501–600	9.20 (0.38)
101–150	1.07 (0.04)	601–700	9.45 (0.39)
151–200	1.43 (0.06)	701–1,000	9.85 (0.41)
201–250	2.46 (0.10)	1,001–1,800	10.80 (0.45)
251–300	3.00 (0.13)	1,801–2,600	11.80 (0.49)
301–350	4.00 (0.17)	2,601–3,400	12.90 (0.54)
351–400	5.00 (0.21)	3,401–4,200	13.95 (0.58)
401–450	6.00 (0.25)	4,201–5,000	15.00 (0.63)
451–500	7.00 (0.29)	>5,000	20.00 (0.84)

Source: MINJUS[9]

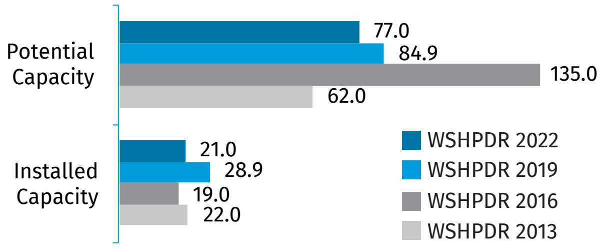
SMALL HYDROPOWER SECTOR OVERVIEW

Cuba has more than one hundred years of experience in the use of hydropower for electricity generation, which was one of the most utilized renewable energy technologies in the first half of the 20th century. Currently, hydropower is the third-largest renewable energy source in Cuba by installed capacity.

There is no official definition of small hydropower (SHP) in Cuba, but unofficially Cuba assumes the terminology of the Latin American Organization of Energy (OLADE) that is less than 5 MW of installed capacity.[10,11] However, for the purposes of this report, a definition of SHP as hydropower plants with an installed capacity of less than 10 MW will be followed.

The current installed operational hydropower capacity in Cuba is 64 MW, with 43 MW from the Hanabanilla hydropower plant and 21 MW from SHP, in accordance with the up to 10 MW definition.[5,12] In comparison with the data from the *World Small Hydropower Development Report (WSHPDR) 2019*, the country's installed SHP capacity has decreased by over 27 per cent while the estimate SHP potential has decreased by 9 per cent, due to access to more accurate data (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Cuba (MW)**



Source: *WSHPDR 2019*,[4] ONEI,[5] *WSHPDR 2013*,[13] *WSHPDR 2016*[14]

As of 2020, there were a total of 170 hydropower plants in Cuba. Of these, 138 were operational SHP plants, including 41 SHP plants connected to the SEN and 97 SHP plants (70 per cent) operating in isolation from the SEN, offering service to 8,486 isolated households.[12,15] Currently, 32 SHP plants are identified as non-operational, of which 25 plants lack water supply as a result of climate change and seven are in need of refurbishment.[12] The nine most productive SHP plants in Cuba are listed in Table 2. Given that some SHP plants were commissioned decades ago, they require refurbishment. For budgetary reasons, only the C. M. de Céspedes SHP plant was refurbished in 2019.

Table 2. **List of Most Productive Operational Small Hydropower Plants in Cuba**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Mayarí MD	Holguín	2.85	43	Reservoir	UNE	2018
Bueycito	Granma	1.46	30	Reservoir	UNE	2012
Nuevo Mundo	Holguín	2.00	44	Reservoir	UNE	2010
Zaza	Sancti Spíritus	2.70	8	Reservoir	UNE	2009
Corojo	Granma	2.00	33	Reservoir	UNE	2003
Chambas	Ciego de Ávila	1.04	29	Reservoir	UNE	2003
C. M de Céspedes	Santiago de Cuba	1.53	34	Reservoir	UNE	1998
Yara	Granma	2.60	42	Reservoir	UNE	1986
Guaso	Guantanamo	1.05	190	Run-of-river	UNE	1917

Source: Peña Pupo & Fariñas Wong[16]

There are two SHP plants to be completed in 2021: the Alacranes SHPP (2.1 MW) in Villa Clara and the Mayarí MI SHPP (1.25 MW) in Holguín (Table 3). Furthermore, in 2020 a feasibility study of one pumped storage hydropower plant of 200 MW in Mayarí was completed.[6,15] Given that Cuba does not have major rivers or large bodies of inland water, the development of hydropower will remain focused on small-scale projects. The technical potential of hydropower in Cuba is estimated, based on preliminary studies, to be 135 MW, including 13.7 MW in channels.[15] This potential was determined by an inventory of potential sites in the 1980s. The study involved cartographic maps and precipitation measurements, with a few cases where a deep hydrological assessment was carried out. Currently, the estimated capacity of some SHP sites is being increased using hydrological assessment based on field investigations. However, the methods used were developed in Cuba in the 1980s. Thus, the current hydrological design remains weak due to the lack of local expertise in SHP. The updated estimate of SHP potential in Cuba is 77 MW, which is based on previous calculations of 56 MW of total planned capacity and the current installed capacity of 21 MW.[15]

Table 3. **List of Ongoing Small Hydropower Projects**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Develwoper*	*Planned launch year*	*Development stage*
Alacranes	Villa Clara	2.10	13.0	EMFRE	2021	Construction
Mayarí MI	Holguín	1.25	13.5	EMFRE	2021	Construction

Source: MINEM[15]

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

In 2016, Cuba signed an agreement with the Kuwait Fund for Arab Economic Development (KFAED), which provided USD 30 million for the construction of 34 SHP projects with a combined capacity of 14.6 MW.[4,17,18] Furthermore, by October 2020, some contracts had been signed with a European supplier (STM Power) for the development of 10 SHP projects and supply of SHP technology. The duration of the project is seven years.[16] Table 4 provides a list of selected sites available for development or refurbishment based on full feasibility studies.

Table 4. **List of Selected Small Hydropower Sites Available for Development and Refurbishment**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site*
Guaso	Guantánamo	1.05	190	Refurbishment
La Paila	Pinar del Río	0.75	19	New
Cautillo	Granma	0.80	21	New
Cauto el Paso 1	Granma	0.65	7	New
Cauto el Paso 2	Granma	0.65	6	New

Source: Peña Pupo & Fariñas Wong[16]

The Government of Cuba drew up plans in 2016 for the development of 74 SHP plants by 2030, representing over 56 MW in capacity (274 GWh), which are available for foreign investment.[19,20] This would nearly double the country's current hydropower capacity, producing an estimated 274 GWh of renewable electricity annually and offsetting up to 230,000 tonnes of CO_2 emissions.[4]

RENEWABLE ENERGY POLICY

The Government of Cuba has recognized the decisive role that renewable energy has to play in the future development of the country. The Government has aspirations to increase the share of renewable energy sources in the country's electricity generation mix to 24 per cent by 2030. This will be composed largely of biomass, wind power and solar PV, with SHP playing a lesser role.[19] The Parliament and the Council of Ministers of Cuba approved the Policy for the Prospective Development of Renewable Energy Sources and the Efficient Use of Energy for 2014–2030 in July 2014.[20] The policy aims to diversify the energy mix by taking into account the use of every renewable energy source. The policy's main objectives are:

- Reducing dependency on fossil fuels and, therefore, increasing energy independence;
- Decreasing the high consumer cost of energy derived from the cost of fuel and the low efficiency of the electricity system;
- Contributing to environmental sustainability;
- Introducing a new foreign investment law.[4,19]

In March 2018, the Government signed Law 345 on the Development of Renewable Sources and the Efficient Use of Energy.[20] The Law also makes provisions for tariff exemptions for the imports of components and equipment for renewable energy projects.[4,20]

The Cuban industry aims to be able to achieve the recovery of production of hydraulic turbines to modernize and upgrade existing SHP facilities. The priorities include the production of new horizontal turbines for micro-hydropower plants as well as the production of speed governors. In addition, the sector looks for foreign investment to strengthen the industry.[15,19] Foreign investments have already contributed to the transition and diversification of the energy mix of Cuba through projects based on solar power, wind power, hydropower, biogas and agricultural as well as industrial residuals such as sugarcane biomass.[19] There are no feed-in tariffs or renewable electricity prices in Cuba, however in the case of foreign investment, the purchase prices and electricity sale can be negotiated.[20]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The Environmental Law (Law 81-1997) laid the foundation for the recognition of the role of renewable energy in the country's development and has been subsequently added to over the past two decades. In the protected areas, severe environmental regulations are applied, making construction in such areas practically impossible. With regard to hydropower, under Resolution 114-1990, the INRH has the competence to approve the entities (including foreign ones) that are authorized to develop a project related to water.[4,21]

Efficient and responsible management and utilization of water resources have become a national priority since the implementation of the Cuban Programme to Combat Climate Change (Programa Cubano de Enfrentamiento al Cambio Climático) of 2007, the 2012 National Water Policy (Política Nacional del Agua 2012) and Law 124-2017 on terrestrial waters.[7]

The Government of Cuba is open to investment from foreign enterprises in renewable energy projects, by means of either joint ventures with Cuban enterprises or fully-foreign investment.[19] However, Foreign Investment Law (Law 118-2014, replacing Law 77-1995) does not include specific legislation for renewable energy sources, as Law 345 or Decree Law 327 do.[21,22] Law 118 and Decree Law 327 establish the procedures for any type of investment in Cuba. According to Decree Law 327, the investor should make a request to the Institute of Physical Planning, which in its turn will provide an answer within a 60-day period, specifying the technological and environmental regulations that the investor is expected to comply with. Once these requirements are satisfactorily met by the investor a certificate of licences for construction is granted.[20]

FINANCIAL MECHANISM FOR SMALL HYDROPOWER PROJECTS

Cuba is one of the few countries in the world that does not have membership in any major international finance institutions, including the International Monetary Fund (IMF), the World Bank and the Inter-American Development Bank (IDB).[4] However, some loans have been guaranteed by international institutions as well as countries with which Cuba has a longstanding trade tradition and relationship.[15] In January 2018, the Cuba Sustainable Energy Forum was held in Havana, which was attended by participants from the European Union, international energy companies and the private sector. Attracting foreign investment is critical for the Government's goal of achieving USD 3.5 billion of investment into the energy sector. Furthermore, Cuba has been strengthening its engagement with the International Renewable Energy Agency (IRENA) through the SIDS Lighthouses Initiative.[4,23]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Droughts, especially those associated with El Niño episodes, have caused enormous impacts during the past 15 years and are projected to severely affect the Caribbean region in the future. For this reason, specific solutions must be implemented to reduce the risk of a lack of electricity production by SHP plants as foreseen in the National Plan to Confront Climate Change, known as Tarea Vida (Project Life).[24] On the other hand, it is important to stress that half of the country's hydropower potential lies in protected regions with a high biodiversity value, one of the reasons why hydropower has not been developed in Cuba on a larger scale until today.[25]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The SHP sector has a tradition of over one hundred years in Cuba. It is also currently growing despite the existing financial and environmental limitations. There is a well identified potential for the construction of new SHP plants. The existence of a law on foreign investments and of a renewable energy policy constitute an advantage for the further development of SHP in Cuba.

The barriers that have limited the use of SHP in Cuba are similar to those that have limited the development of other renewable energy sources in the country. These technical, social, institutional, economic, financial and regulatory barriers include:

- Lack of advanced technologies to further study hydropower potential;
- Limited financial resources;
- Limited technical capacity to carry out feasibility studies;
- Limited ability of the national industry to ensure the availability of equipment, components and spare parts;
- Low usage of the existing production capacities;
- Limited scientific and technological capacity of the hydropower sector;
- Insufficient maintenance of existing facilities.[26,27]

The main enablers for SHP development in Cuba are as follows:

- Well studied potential hydropower projects available for foreign investment;
- Existence of Government renewable energy plans;
- Existence of legislation and regulations supporting foreign investment.

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Dominica

Davy Rutajoga, International Center on Small Hydro Power (ICSHP)

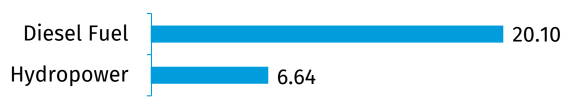
KEY FACTS

Population	71,991 (2020)[1]
Area	751 km^2 [2]
Topography	Considered the largest and most northerly of the Windward Islands, the country is also part of the rugged Lesser Antilles volcanic arc. An island of volcanic origin, the terrain is very rugged with some active volcanoes and a number of hot springs. Mountains cover both the northern and southern interior, with a small plain in the centre. Its vegetation is lush and green, with dense forests and a tropical flora on steep slopes. The slopes in Dominica vary in elevation from 300 to 1,400 metres above sea level. Its highest peak is Morne Diablotins situated in the northern interior of the island, which reaches 1,447 metres.[2]
Climate	Dominica has a tropical wet climate, characterized by heavy rainfall and warm temperatures. Temperatures rarely fluctuate and the average temperature throughout the year is 27 °C near the coast and in high altitudes it is cooler with an average of 20 °C. During the summer months of July and August days are hot and humid with temperatures typically around 32 °C.[2,3]
Climate Change	An island state in the Caribbean, Dominica is especially vulnerable to a rise in sea level and an increase in natural disasters. Hurricanes are expected to become more prevalent and intense in the upcoming decades, while overall annual rainfall is expected to decrease. Average temperatures have already increased more than 1 °C in the past century along with the number of extremely hot days. These trends are anticipated to accelerate by the end of this century.[3]
Rain Pattern	The weather in Dominica is characterized by strong rains, with rainfall ranging from 1,500 mm at sea level to above 6,000 mm in mountainous areas. The island has both a rainy and a dry season, the former between July and December and the latter from January to June. Hurricanes and tropical storms from the Atlantic Ocean occur during the wet season peaking during late August and September.[2,3]
Hydrology	Dominica contains 365 rivers as well as many waterfalls, which are evenly dissipated across the country. The Layou river is the longest and flows from east to west in the central region. The Roseau, Pagua and Toulaman are the other major rivers and flow from the interior down to the coasts. Most streams are non-navigable but can be used for hydropower generation.[2]

ELECTRICITY SECTOR OVERVIEW

At the end of 2020, total installed capacity in Dominica was 26.74 MW that satisfied a peak demand of 15.96 MW. Of the total installed, diesel fuel accounted for 20.10 MW (75 per cent) and hydropower accounted for 6.64 MW (25 per cent) (Figure 1).[4] Minimal solar and wind power also exists within the country but are self-generated at the residential or commercial level.[5] Accurate data on installed capacity of solar and wind power are currently unavailable. There are a total of five major power plants in the country. The two diesel plants are Fond Cole (13.3 MW) and Sugar Loaf (6.8 MW) and the other three are hydropower plants at Laudat (1.24 MW), Trafalgar (3.52 MW) and Padu (1.88 MW). Available capacity in 2020 was lower than installed due to damages to plants, especially at the Padu hydropower plant that has been damaged since Hurricane Maria in 2017 and still has not been repaired.[4,6]

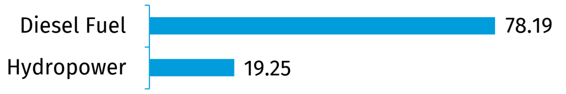
Figure 1. **Installed Electricity Capacity by Source in Dominica in 2020 (MW)**



Source: DOMLEC[4]

In 2020, total electricity generation in Dominica by the country's electricity company, DOMLEC, was 97.45 GWh. Diesel fuel generated 78.19 GWh (approximately 80 per cent) and hydropower 19.25 GWh (20 per cent) (Figure 2). Total electricity sold in the country was 85.5 GWh. Residential customers consumed 40.78 GWh, commercial customers (excluding hotels) consumed 36.41 GWh, industry consumed 3.46 GWh, hotels consumed 2.83 GWh and street lighting consumed 2.03 GWh. Power plants used 3.57 GWh themselves and the remaining 8.37 GWh was considered as losses.[4]

Figure 2. **Annual Electricity Generation by Source in Dominica in 2020 (GWh)**



Source: DOMLEC[4]

Access to electricity in Dominica is 100 per cent.[7] Electricity security in the country, however, is vulnerable to weather volatility and oil price shocks. During the dry season, the hydropower plants are unable to produce at their full capacity.[4] In addition, inclement weather and storms can easily damage the country's electrical infrastructure. Hurricane Maria in 2017 demonstrated how vulnerable the infrastructure was, affecting the entire grid and leaving almost all of the population without power for months. The transmission and distribution system were nearly completely destroyed, with 40 per cent of the system torn down and needing repairs and another 25 per cent was unrepairable and needing to be fully replaced. The irremediable damage was disproportionately higher in rural areas.[5] Since this natural disaster, heavy focus has been put on making the system much more resilient for the future.

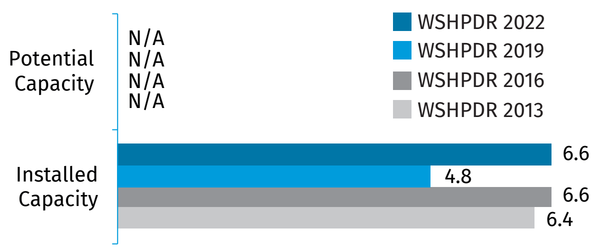
The one electrical utility company in the country is Dominica Electricity Services Limited (DOMLEC). The majority of the company is owned by private investors with Light and Power Holdings being its majority shareholder, owning 52.8 per cent. DOMLEC is the country's principal generator of electricity, although independent power producers (IPPs) are allowed to generate electricity with a licence as per the Electricity Supply Act of 2006. Transmission and distribution rights are still exclusive to DOMLEC. The Independent Regulatory Commission (IRC) is responsible for regulating the sector and issuing the generation licences.[6]

Electricity tariffs in Dominica depend on consumer type. For residential consumers prices are 0.11 USD/kWh for the first 50 kWh and 0.13 USD/kWh for additional consumption above 50 kWh. For industries and hotels prices are 0.12 USD/kWh from 6 am to 10 pm and are 0.11 USD/kWh from 10 pm to 6 am. For commercial consumers and street lighting prices are 0.13 USD/kWh.[8] In April 2022 the IRC was to carry out a tariff review of DOMLEC, with tariff values subject to change as a result.[9]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Dominica refers to plants of up to 10 MW. The installed capacity of SHP was 6.64 MW at the end of 2020. The country has three SHP plants: Laudat with an installed capacity of 1.24 MW, Trafalgar with 3.52 MW and Padu with 1.88 MW.[4] All three plants are owned and operated by DOMLEC. The exact SHP potential in the country is unknown although it has been found that there is untapped potential within the island. A qualitative hydropower potential assessment indicated there was hydropower potential in the Belfast, Layou, Rosalie, Roseau and White Rivers but the undertaken study did not quantify the potential.[10] In comparison with the *World Hydropower Development Report (WSHPDR) 2019*, potential capacity has remained unknown and installed capacity has recovered its 6.64 MW level due to the knowledge that the Padu plant will not be permanently shut down because of the damage caused by Hurricane Maria (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Dominica (MW)**



Sources: DOMLEC,[4] *WSHPDR 2019*,[10] *WSHPDR 2016*,[11] *WSHPDR 2013*[12]

Hydropower was first implemented in the country in 1952 with the 0.64 MW Old Trafalgar plant and then in 1967 the 1.88 MW Padu plant was commissioned.[13] Decades later, Dominica expanded its electricity generated through hydropower by implementing the Dominica Hydroelectric Expansion Project, which led to the Laudat power plant commencing its service in December 1990. The Old Trafalgar power plant was replaced by the New Trafalgar in September 1991.[14]

In 2017, Hurricane Maria severely affected the entire country, including its existing hydropower facilities. A study of the Roseau River area found that the Trafalgar hydropower plant only experienced minor damages to the building structure, while the Laudat plant remained intact.[15] Conversely, the Padu hydropower plant was severely affected, with the flooding of its powerhouse and damage to its electrical installations. This has caused the plant to be unable to operate, which remained to be so as of the start of 2022. Plans to recover this plant, however, are in place and international bidding for the rehabilitation project was announced in February 2022.[16]

RENEWABLE ENERGY POLICY

A National Energy Policy (NEP) was drafted in 2011 and revised in 2014, asserting the country's objective for self-sufficient electricity generation through sustainable resources by 2020. It suggested that renewable energy should be included in the energy mix whenever economically feasible. Hydropower, solar power and geothermal power were all listed as having high potentials that should be further studied and developed. Geothermal power was the only one quantified with a capacity target, expecting a capacity of 120 MW to be fully operational by 2020.[17] In reality, high set-up costs have severely hindered reaching this expectation so in order to push geothermal development, the Government created the publicly-owned Dominica Geothermal Development Company Ltd. (DGDC) in 2016, which, at the moment of writing of this chapter, was in the process of constructing a 10 MW geothermal project with USD 50 million invested from the Government.[18] This NEP also suggests enacting financial incentives for renewable energy development; however, no such incentives have been put in place.[17]

In response to the immense damage of the electricity infrastructure caused by Hurricane Maria in 2017 and the need for a more resilient system, the Sustainable and Resilient Energy Plan (S-REP) of 2019 was created. This plan stresses the need to strengthen the country's transmission and distribution systems, to diversify the energy mix with more renewable energy sources and to reinforce grid stability for the most vulnerable communities. Analyses of six scenarios of possible energy mixes were carried out to find the most cost-effective way to maximize resiliency and two scenarios were identified as optimal, depending on actual geothermal output achievements. The most optimal scenario constitutes increasing hydropower capacity to 7.2 MW, geothermal power to 12.8 MW and keeping existing diesel for back-up. However, in the case that geothermal power becomes too expensive to implement at such a capacity, then alternatively increasing solar power to 6.2 MW, wind power to 6.6 MW, geothermal power to 6.4 MW and keeping diesel for back-up, would be satisfactory.[19] All sustainable development programmes and projects in Dominica are coordinated by the Environment Coordinating Unit (ECU) of the Ministry of Environment, Natural Resources, Physical Planning and Fisheries. The ECU is funded primarily by internal sources and collaborates with the Government of the Commonwealth of Dominica and the private sector agencies on developing renewable energy policies as well as tackling environmental issues.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The barriers to SHP development in Dominica include:

- The current focus on electricity generated through geothermal resources has shifted the Government interest away from other renewable energy sources;
- Progress in eco-tourism and the frequent use of rivers for this purpose prevents future hydropower development;
- Dominica lacks economic and financial incentive mechanisms for SHP, such as feed-in-tariffs or tax benefits;
- Privately-owned properties make land-acquisition for hydropower difficult.[10]

The enablers for SHP development in Dominica include:

- Hydropower projects have a lower cost of developing than geothermal projects;
- As SHP plants have been in operation in the country for several decades, there is local operating knowledge;
- An increase in hydropower would decrease the country's high dependency on imported fossil fuels.

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Dominican Republic

Michela Izzo, Guakía Ambiente; Alberto Sánchez, GEF Small Grants Programme; and Mario Vera Barranco, Guakía Ambiente

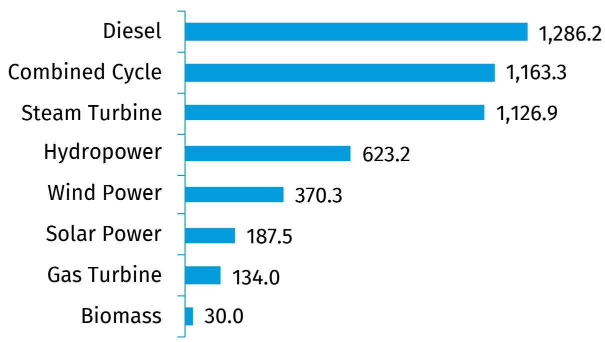
KEY FACTS

Population	10,448,499 (2020) [1]
Area	48,311 km² [2]
Topography	The Dominican Republic has four main mountainous chains: the Cordillera Septentrional, the Cordillera Central, the Sierra de Neyba and the Sierra de Bahoruco. These chains run approximately parallel to each other with a north-west, south-east orientation and are separated by three major valleys: the Cibao, the San Juan and the Enriquillo. Pico Duarte is the highest peak in the country, on the island of Hispaniola and in the entire Caribbean, reaching 3,098 metres.[3]
Climate	The Dominican Republic has a tropical climate, ranging from arid to very humid, with high ecosystem diversity. This is associated with the physical geography of the country that is characterized by mountain chains, which create a barrier to trade winds, producing very different conditions between the windward and leeward sides. The average temperature ranges between 7 °C (at the highest altitudes) and 31 °C (at the Enriquillo Lake in the southern region).[3]
Climate Change	Historical trends show a significant increase in air temperature (3.0±0.5 °C for minimum and 1.8±0.4 °C for maximum air temperature in the period 1936–2007) and significant change in rain patterns, with typical reduction in precipitation on the leeward side of the main mountain chains and the western side of the country.[4] These trends are expected to continue and intensify in the future, according to the most accredited climate change scenarios.[5]
Rain Pattern	Variations in topography lead to differences in precipitation of up to 2,400 mm between the north-eastern and south-western sides of the Cordillera Central. The wettest areas are located in the north-eastern part of the country, which receive annual rainfalls of over 3,000 mm, while the driest areas can be found in the Enriquillo Valley, in the south-west, with less than 450 mm of precipitation per year.[3]
Hydrology	The Yaque del Norte (296 km) is the longest river in the Dominican Republic. The longest river on the island of Hispaniola is the Artibonite (321 km); however, only 68 km of it are located in the Dominican Republic. On the other hand, the largest river of the country is the Yuna, with an average flow of 97.6 m³/s.[6] Lake Enriquillo is the largest lake not only in the Dominican Republic, but also in the entire West Indies.[3]

ELECTRICITY SECTOR OVERVIEW

In 2020, total installed capacity in the Dominican Republic stood at 4,921.4 MW, representing an increase of approximately 42 per cent compared with 2016. Of the total installed capacity, approximately 26 per cent came from diesel plants, 24 per cent from combined cycle plants, 24 per cent from steam turbine plants and 3 per cent from gas turbine plants (Figure 1). Renewable energy sources contributed approximately 24 per cent of the total, with hydropower, the country's most important energy source after fossil fuels, providing 13 per cent and wind power plants 8 per cent. Biomass was recently added to the country's energy mix, with a 30 MW plant installed in the south-east of the country.[7,8,9]

Figure 1. **Installed Electricity Capacity by source in the Dominican Republic in 2020 (MW)**



Source: OCSENI,[7] Sanchez & Izzo[9]

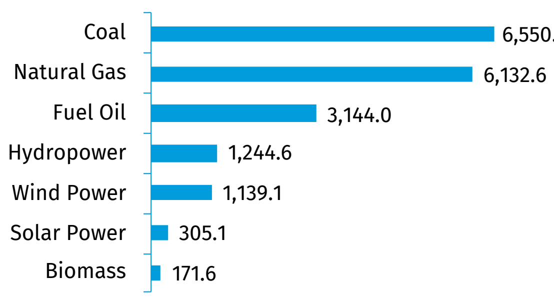
Total gross generation in 2020 reached 18,687.6 GWh, while net supplied electricity was 17,411.5 GWh. Of total electricity generation, coal contributed 35 per cent (with a significant increase from previous years due to the launch of the Punta Catalina power plant), natural gas 33 per cent, fuel oil 17 per cent, hydropower 7 per cent, wind power 6 per cent, solar power 2 per cent and biomass 1 per cent (Figure 2). Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, there was a significant increase in both generation from fossil fuels (especially carbon and diesel) and generation from renewable energy sources, especially solar and wind power, while generation from hydropower remained basically stable.[7,8,9]

Table 1. **List of Operational Small Hydropower Plants in the Dominican Republic**

Name	*Location*	*Capacity (MW)*	*Head*	*Plant type*	*Operator*	*Launch year*
Brazo Derecho	Santiago province, UFE Canal	2.9	24.5	Kaplan	EGEHID	2011
Las Barías	Peravia province, Marcos A. Cabral Canal	0.9	9.9	Kaplan	EGEHID	2010
Magueyal 1	Azua province, Ysura Canal	1.5	60.0	Francis	EGEHID	2009
Magueyal 2	Azua province, Ysura Canal	1.5	60.0	Francis	EGEHID	2009
Rosa Julia de la Cruz	María Trinidad Sánchez province, Boba River	0.9	10.5	Kaplan	EGEHID	2005
Domingo Rodríguez 1	San Juan province, José Joaquón Puello Canal	2.0	54.4	Francis	EGEHID	2004
Domingo Rodríguez 2	San Juan province, José Joaquón Puello Canal	2.0	54.4	Francis	EGEHID	2004
Aniana Vargas 1	Monseñor Nouel province, Yuboa River	0.3	40.0	Francis	EGEHID	2003
Aniana Vargas 2	Monseñor Nouel province, Yuboa River	0.3	40.0	Francis	EGEHID	2003
Los Toros 1	Azua province, Ysura Canal	4.9	N/A	Francis	EGEHID	2001
Los Toros 2	Azua province, Ysura Canal	4.9	N/A	Francis	EGEHID	2001
Los Anones	Peravia province, Marcos A. Cabral Canal	0.1	7.0	Francis	EGEHID	1999
Contra embalse Monción 1	Santiago Rodríguez province, Mao River	1.6	15.5	Francis	EGEHID	1998
Contra embalse Monción 2	Santiago Rodríguez province, Mao River	1.6	15.5	Francis	EGEHID	1998
El Salto	La Vega province, Constanza River	0.7	77.0	Ossberger	EGEHID	1995
Baiguaque 1	Santiago province, Baiguaque River	0.6	78.0	Ossberger	EGEHID	1995
Baiguaque 2	Santiago province, Baiguaque River	0.6	78.0	Ossberger	EGEHID	1995
Nizao Najayo	San Cristóbal province, Nizao-Najayo Canal	0.3	10.0	Ossberger	EGEHID	1994
Hatillo	Juan Sánchez Ramírez province, Yuna River	8.0	30.0	Francis	EGEHID	1984
Sabaneta	Azua province, San Juan River	6.3	70.0	Francis	EGEHID	1981
Las Damas	Independencia province, Las Damas River	7.5	304.0	Pelton	EGEHID	1967
Jimenoa	La Vega province, Jimenoa River	8.4	212.7	Francis	EGEHID	1950
Community micro hydropower systems (56)	Various upland basins	1.5	37-150	Mainly Pelton, but also Francis, Turgo, and Mitchell-Banki	Beneficiary communities	1998

Source: INDRHI,[22] Rodríguez Taveras,[23] CESEL Ingenieros[24]

Figure 2. **Electricity Generation by Source in Dominican Republic in 2020 (GWh)**

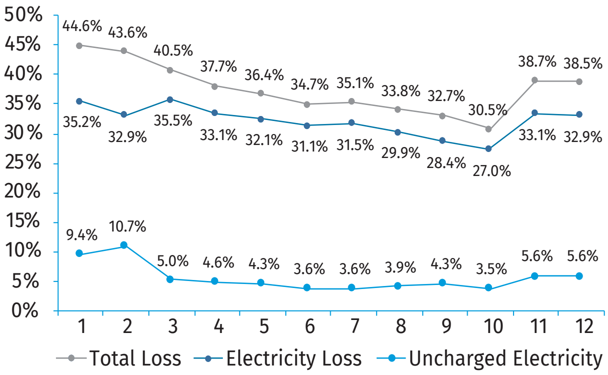


Source: OCSENI,[7] Sanchez & Izzo[9]

The national electricity system of the Dominican Republic has progressively improved in quality. Nevertheless, problems persist, both in terms of energy provision and in terms of quality of transmission and distribution. In order to limit losses and reduce the electricity subsidy, the distribution enterprises (EDEs) have established maximum unit costs for dispatch to the National Interconnected Electric System (SENI), consequently causing an unsatisfied demand. In 2020, the monthly average power demand supply shortfall was 60 MW.[7] Furthermore, the electricity system is characterized by frequent interruptions and a high loss rate both in the transmission and distribution system — over 30 per cent of the total generated electricity (Figure 3).[10] The Dominican Republic experiences one of the highest frequencies of blackouts among countries in the region, exceeding 30 days annually on average.[11] Available capacity stands on average at approximately 22 per cent of installed capacity.[12]

The inability to provide a reliable service at reasonable prices has caused a segmentation of the electrical market into three main groups: SENI's users, who are connected to the national grid and constitute 83 per cent of the market at present; self-producers (10 per cent of the market), typically large consumers such as industrial and mining companies that have their own generation systems to satisfy their internal demand and sell the surplus to SENI; and isolated systems (7 per cent of the market), which operate independently and are not connected to SENI.[13]

Figure 3. **Electricity Loss Rate of Distribution Enterprises as a Percentage of Electricity Charged in the Dominican Republic in 2009–2020 (%)**

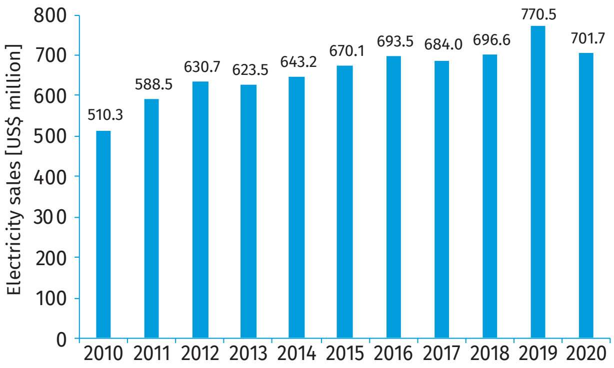


Source: CREES[10]

In terms of access to electricity, the Dominican Republic has made progress in recent years, reaching 100 per cent of urban electrification, while in rural areas electricity access is estimated at 98 per cent.[14,15]

Fossil fuels, which are imported, continue to be the main source of fuel for electrical generation. Given the rising trend in electricity demand, the rate of fossil fuel consumption related to electrical generation is also growing. The expenditure of the residential and commercial sectors on electricity has increased by more than 40 per cent between 2009 and 2019 (Figure 4).[7,16] National projections indicate that energy demand will continue to grow at an average rate of 2–3 per cent per year in the period 2010–2030.[17]

Figure 4. **Electricity Sales to Regular Commercial and Residential Customers in the Dominican Republic in 2009–2019 (USD million)**



Source: CDEEE[16]

The Dominican electrical system is state-owned. However, both the Government and the private sector participate in the generation, transmission, distribution and commercialization of energy. The Coordinator of the National Interconnected System (OCSENI) is the state agency responsible for coordinating the transmission, generation and distribution within SENI. Through Law 141–97, five enterprises were created, two for thermal generation (Electricity Generation Enterprises ITABO and HAINA — EGEITABO and EGEHAINA, respectively) and three for distribution (Electricity Distribution Enterprises of the North, South and East — EDENORTE, EDESUR and EDEESTE, respectively). Both transmission and hydropower generation belong to the state, through two enterprises: one for transmission (Dominican State Transmission Enterprise — ETED) and one for hydropower (Dominican Hydropower Generation Enterprise — EGEHID). The Dominican Corporation of State Electrical Enterprises (CDEEE) is responsible for the management of electrical enterprises and the implementation of state programmes for rural and urban electrification, guaranteeing synergy, effectiveness, profitability and sustainability.[8]

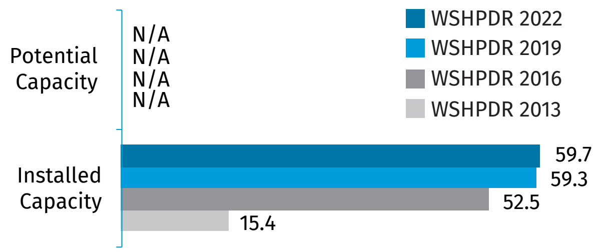
The Dominican Republic continues to have one of the most expensive electrical systems in the Caribbean and Central America. In 2019, final customers had to pay more than 0.15 USD/kWh, over two times the 0.06 USD/kWh paid by customers connected to the off-grid community-owned hydropower plants supported by the Small Grants Programme and the Government of the Dominican Republic, as outlined below.[9,16,18]

There are two different types of electricity subsidies in the Dominican Republic. The first type is the "Bonoluz, 3 in 1", which is a full subsidy of electricity consumption up to 100 kWh for customers who have been selected by the Social Cabinet of the Government. For additional consumption, a further subsidy is provided in the form of a lower tariff, and the fixed charge for consumption is also fully subsidized. The second type of subsidy is the Fund for the Stabilization of the Electric Tariff (FETE) which compensates tariff differences caused by the fluctuations in the cost of imported fuels used for power generation.[8]

SMALL HYDROPOWER SECTOR OVERVIEW

In the Dominican Republic, small hydropower (SHP) is classified as plants with a total capacity of up to 10 MW. Installed SHP capacity in 2020 stood at approximately 59.7 MW, with a total of 76 operational SHP plants, which contributed nearly 10 per cent of the total hydropower installed capacity.[9,19] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity slightly increased due to the construction of additional community-operated SHP plants, while the nationwide potential remains unknown (Figure 5).

Figure 5. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in the Dominican Republic (MW)**



Source: Sánchez & Izzo,[9] *WSHPDR* 2019,[8] EGEHYD,[19] *WSHPDR 2013*,[20] *WSHPDR 2016*[21]

In 2020, there were 16 state-owned SHP plants consisting of 22 individual power blocks operating in the country with a combined installed capacity of 57.8 MW, all operated by EGEHID.[7] More than 60 per cent of the plants have a capacity of less than 2.5 MW. The majority of these SHP plants, accounting for 80 per cent of the total SHP installed capacity, are located in the Cordillera Central, the main mountain chain of the country. The real capacity of the state-owned SHP plants available to the national electricity system of the Dominican Republic is approximately 45 per cent of their installed capacity on average. In addition, as of 2020 there were 56 community-owned micro-hydropower plants operating in the country, of which 47 were constructed through a partnership between the Government of the Dominican Republic and the Global Environment Facility Small Grants Programme (GEF SGP) and a further 9 were financed solely by the Government. The capacities of these micro-hydropower plants range from 10 kW to 150 kW, with a combined installed capacity of 1.5 MW (Table 1).[7,30]

A comprehensive study on SHP potential in the Dominican Republic has not yet been carried out. One study, which was due to start in 2018 as a collaboration among the Ministry of Energy and Mines, the GEF SGP, the Technological Institute of Santo Domingo (INTEC) and the Dominican non-governmental organization Guakía Ambiente, was delayed. Nevertheless, a pilot study to evaluate micro-hydropower potential was carried out as part of an MSc thesis in 2020, as a collaboration between the University of Madrid, Guakía Ambiente and the GEF SGP. The pilot study was implemented in the Nizao basin, a 1,038 km^2 watershed in the south-eastern region and one of the priority basins of the country, both in terms of water provision and of electricity generation.[25] The study identified 72 river sections appropriate for the installation of micro-hydropower plants: 27 sections between 19 kW and 40 kW, 19 between 40 kW and 70 kW, 13 between 70 kW and 148 kW, 4 between 148 kW and 244 kW, 5 between 244 kW and 372 kW and 4 of more than 372 kW.[26] While these partial results cannot be adopted as an estimate of the nationwide SHP potential, the results and their potential applications confirm the importance of expanding the pilot study to the whole country.

The aforementioned study is especially relevant to organizing rural electrification in a more efficient and effective way, due to the significance that community micro-hydropower generation has acquired in the Dominican Republic as a successful model for sustainable development. The Dominican Government, following Law 57-07 on Incentives to Renewable Energy and in collaboration with multiple stakeholders, continues to promote micro-hydropower as a solution to guarantee electricity access to rural communities while fostering local empowerment. As of 2021, 60 community-owned micro-hydropower plants were in operation, providing clean reliable energy to more than 4,600 families, schools, rural health and community centres, micro-enterprises and communication centres in rural isolated areas. Furthermore, these systems are contributing to global warming mitigation, with a reduction of more than 28,000 tons of CO_2 per year and conservation of over 70 km^2 of forest.[9,27,28,29]

Ten additional SHP plants are currently under construction, with a total capacity of more than 490 kW, which will benefit over 1,100 additional families in isolated rural areas.[27] Several ongoing projects are listed in Table 2, while one potential identified SHP site is listed in Table 3.

Table 2. **List of Selected Ongoing Small Hydropower Projects in the Dominican Republic**

Name	*Location*	*Capacity (kW)*	*Head*	*Developer*	*Planned launch year*	*Development stage*
Los Montazos	La Vega province	50	49	SGP/ Guakía Ambiente	2021	75%
La Yuca – Florencio	San José de Ocoa province	44	80	SGP/ Guakía Ambiente	2022	50%
Los Martínez	San José de Ocoa province	50	135	SGP/ Guakía Ambiente	2022	50%
La Malanga	Barahona province	20	82	SGP/ Guakía Ambiente	2022	40%
Angostura	La Vega province	75	57	SGP/ Guakía Ambiente	2023	35%

Source: SGP/Guakía Ambiente[30]

Table 3. **Potential Small Hydropower Site in the Dominican Republic**

Name	*Location*	*Potential capacity (kW)*	*Head*	*Type of site (New/ Refurbishment)*
Sonador	Monseñor Nouel province	100	50	New

Source: SGP/Guakía Ambiente[30]

Due to the COVID-19 pandemic, community micro-hydropower projects in the Dominican Republic have suffered delays and difficulties, which have slowed the increase in the number of such plants throughout the country.

The Dominican Republic is sharing its successful experience in community micro-hydropower with other Latin American countries (Venezuela, Haiti and Mexico), promoting the application of principles that ensure a sustainable model of micro-hydropower development:

- Community-based approach;
- Development of local solutions;
- Replicability, through adaptation to each specific context;
- Local empowerment, based on the following: respect for the habits and peculiarities of local populations; active participation of people and local groups; learning by doing; improvement of local skills and knowledge; integrated development; and networking and multi-stakeholder synergy. [31]

RENEWABLE ENERGY POLICY

One of the instruments of national policy on renewable energy in the Dominican Republic is the Incentive to the Development of Renewable Energy Sources (Law 57-07) and the corresponding regulations (in particular, No. 10469 of 30 May 2008). The law introduced a target of 20 per cent of national energy consumption to be produced from renewable energy sources by 2020, with the aim of reducing the dependence on imported oil and other liquid fuels. This goal is confirmed by the National Strategy of Development 2030 (Law 01-12), which set the goal of reducing per capita CO_2 emissions by 25 per cent by 2030 with respect to the 2010 baseline.[32] The Government will continue promoting renewable energy over the coming decade, planning to generate 23 per cent of all electricity at the national level from renewable energy sources by 2030. These goals will be reached through structural interventions to improve the national electricity system, as well as changes to the national energy mix.[10]

The regulations for the application of Law 57-07 establish incentives and feed-in tariffs (FITs) for renewable energy, according to the specific source. However, these do not apply to hydropower, small or otherwise. For other RES, FITs range from 0.0487-0.5350 USD/kWh.[29]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP projects are primarily regulated by the General Law on Electricity (125-01), which created the Dominican Hydropower Generation Enterprise (EGEHID), the entity that is responsible for managing all hydropower owned by the Government of the Dominican Republic.[33] SHP projects up to 5 MW can apply for incentives under Law 57-07. In these cases, the state grants concessions to private companies or individuals.

COST OF SMALL HYDROPOWER DEVELOPMENT

Cost of SHP development is highly variable, depending on site conditions, accessibility, technology and grid distribution (where applicable). At present, no case studies are available on the matter. According to the experience of the GEF SGP, the cost of SHP development in the Dominican Republic falls within the range of 6,500–19,500 USD/kW.[34]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

A variety of financial mechanisms are implemented for project development. In case of the Government-developed projects, most have been financed by loans from international banks and less frequently through local funds by selling energy through EGEHID. In case of community SHP projects, financial mechanisms are based on different sources, including international cooperation, the national Government, the private sector, civil society organizations and local communities. During the past 20 years, the GEF SGP has been the main promoter of SHP, with the implementation of more than 50 projects.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate crisis is significantly affecting SHP development in the Dominican Republic. On the one hand, the increase in frequency of intense rain, as well as in intensity of tropical cyclones, exposes SHP infrastructure to damage, causing suspension of operations.[4,35] On the other hand, prolonged and intense droughts significantly reduce water flow, thus causing shortages in the provision of electricity.[32] A recent study, carried out on SHP projects supported by the GEF SGP and Guakía Ambiente, revealed that during the period 2015–2018, characterized by the incidence of El Niño, approximately 30 per cent of the plants reduced their generation, while another 15 per cent went out of operation for at least one month.[36]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

SHP generation continues to be a feasible alternative to fossil fuels for electrification in the Dominican Republic, especially in rural isolated areas, where a small percentage of the population persists without access to electricity. Decentralized management is highly recommended to ensure sustainability and to promote local development, especially in case of SHP plants with an installed capacity up to 500 kW.

Many barriers to effective SHP development in the country persist and additional challenges have arisen in recent years, including the following:

- Climate change impacts including intense rain, tropical cyclones, and prolonged drought;
- Insufficient data on undeveloped SHP capacity and potential sites, particularly on the national level;
- Lack of private sector engagement in SHP development;
- Lack of opportunities and mechanisms for knowledge exchange in the SHP sector;
- Lengthy administrative procedures, especially for community-run SHP projects.

Enablers for SHP development include:

- Experience with SHP development and operation and well-organized SHP sector;
- Availability of international financing for SHP projects;
- Some studies of potential SHP sites are available.

Recommended measures in support of SHP development in the Dominican Republic include the following:

- Carrying out a study on SHP potential at the national level;
- Decentralization in decision making;
- Diffusion of a shared vision of integral development, based on local empowerment as a key assumption for sustainability;
- Capacity building for fund management at community level;
- Strengthening of public-private-community alliances, through effective mechanisms of collaboration towards common objectives;
- Opening of opportunities for feeding directly into the grid for SHP plants up to 5 MW;
- Effective application of Law 57-07, especially regarding the commitment to devote 5 per cent from taxes on fossil fuels to renewable energy;
- Providing access to Bonoluz subsidy for households connected to micro-hydropower plants;
- Easy access to the carbon market for community micro-hydropower projects;
- Networking to facilitate knowledge exchange and promote mutual support, while focusing on tackling existing issues in the energy sector;
- Climate change adaptation and land degradation reduction in the main watersheds of the country;
- Ensuring reliable data availability and access.

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Grenada

Laura Stamm, International Center on Small Hydro Power (ICSHP)

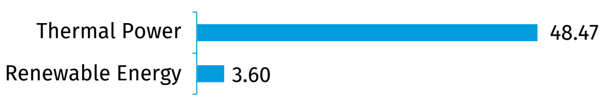
KEY FACTS

Population	112,519 (2020)[1]
Area	345 km² (incl. the islands of Grenada, Carriacou and Petite Martinique)[2]
Topography	The oval-shaped main island of Grenada has a rugged terrain of volcanic origin. It features several forested steep slopes rising from sea level. The highest point is Mount Saint Catherine at 840 metres, situated towards the northern interior of the island.[2]
Climate	Grenada has a tropical climate, with an average temperature of 28 °C. Daytime temperatures vary between 26 °C and 32 °C, while at night temperatures can drop to between 19 °C and 24 °C. There is little variation in temperature throughout the year and seasons are categorized by precipitation with the dry season being between January and May and the wet season between June and December.[3]
Climate Change	An increase in major natural disasters is the most critical concern for Grenada on the issue of climate change. Hurricanes are expected to become larger and more frequent in the upcoming decades. In addition, a rise in sea levels could cause devastating damage to the country as most of the population and infrastructure is located along the low-lying coasts. Sea levels have started to rise on the shores at an average rate of 3.6 mm per year since 1993. Some rivers, already prone to flooding, will also most likely experience more dramatic floods in the future.[4]
Rain Pattern	Rainfall varies between altitudes and seasons. Average precipitation on the coasts is 1,500 mm per year and can reach approximately 4,000 mm per year in the interior highlands. The most rainfall is experienced between June and December. It is during these months that tropical storms or hurricanes can occur.[2]
Hydrology	The country has over 70 rivers, mostly small, typically flowing downwards from the higher altitudes in the interior. Of these, there are eight rivers of consequence: Grand River, Beausejour, Pearls, Saint Patricks, Bailes Bacolet, Antoine, Saint Johns and Saint Marks. The rivers are subject to flooding during the wet season, particularly in the upper parts in higher elevations. The largest lake is Grand Etang with a surface area of 8 hectares, located in a dormant volcanic crater.[3]

ELECTRICITY SECTOR OVERVIEW

At the end of 2020, the total installed capacity in Grenada was 52.07 MW that satisfied a peak demand of approximately 32 MW. Over 93 per cent, more than 48 MW, of the capacity was thermal power, primarily diesel fuel. The remaining 7 per cent, or almost 4 MW, was from renewable energy sources, primarily solar power and minimal wind power (Figure 1). The majority of the renewable energy (2.4 MW) was generated through solar photovoltaics (PV) panels of private customers whose excess after personal use is fed back into the grid.[5]

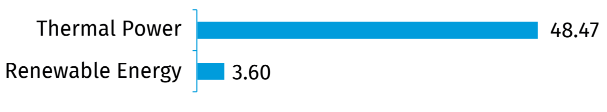
Figure 1. **Installed Electricity Capacity by Source in Grenada in 2020 (MW)**



Source: GRENLEC[5]

Total electricity generation in Grenada for the year of 2020 was 222.7 GWh. Thermal power generated 218.5 GWh, or 98 per cent, and the remaining 4.2 GWh, or 2 per cent, was generated with renewable energy (Figure 2). Subtracting the energy used to operate the power plants themselves, total net electricity generation was almost 213 GWh. Of this, just under 105 GWh (49 per cent) was consumed by the commercial sector, 84 GWh (39 per cent) was consumed by the residential sector and 11 GWh (5 per cent) was used for street lighting. The country experienced an approximately 7 per cent loss in electricity for the year.[5] The electrification rate in Grenada was over 95 per cent as of 2020.[6]

Figure 2. **Annual Electricity Generation by Source in Grenada in 2020 (GWh)**



Source: GRENLEC[5]

Grenada Electricity Services Limited (GRENLEC) is the only electricity company in the country and is therefore responsible for all the generation, transmission and distribution of electricity. GRENLEC was a state-owned company prior to 1994 when it was privatized due to the passing of the Electricity Supply Act that year. The act guaranteed GRENLEC as the sole producer of electricity in the country, but allowed ownership of the company to be transferred to private entities. Consequently, controlling shares were sold to WRB Enterprise from the United States.[7]

The sector was then restructured with the passing of the new Electricity Supply Act of 2016 and the Public Utilities Regulatory Commission Act of 2016. These acts ended GRENLEC's monopoly in the sector, allowing for new entities, domestic or foreign, to begin generating electricity including self-generation for individuals and created a regulatory commission to oversee tariffs in the sector.[7,8] The Electricity Supply Act also called for the promotion of renewable energy and obligates preference given to generators of renewable energy for licences.[9] In the years following the acts, GRENLEC remains the principal supplier of electricity, although its ownership has changed. As of December of 2020, the Government of Grenada repurchased over 71 per cent of the company's shares from WRB Enterprises, making the state the majority owner again.[5]

The base rates of electricity in Grenada depend on the type of consumer in which some types also carry a surcharge for horsepower, floor area or an environmental levy. A value-added tax (VAT) is then added to the final cost for all consumers. Fuel surcharges are calculated based on a three-month average. In March 2022, the base fuel charge for all types of consumers was XCD 0.5288 (USD 0.20) per kWh. The non-fuel charge is different for each type of consumer: for domestic customers it is XCD 0.3043 (USD 0.11) per kWh, for commercial customers it is XCD 0.3281 (USD 0.12) per kWh, for industrial customers it is XCD 0.2405 (USD 0.089) per kWh and for street lighting it is XCD 0.2875 (USD 0.11) per kWh.[10]

SMALL HYDROPOWER SECTOR OVERVIEW

As there is no local definition for small hydropower (SHP). In this chapter it is defined as plants with a capacity of up to 10 MW. While potential SHP capacity in Grenada is estimated to be approximately 7 MW, there is currently no installed capacity. This information remains the same compared to the previous editions of the *World Small Hydropower Development Reports (WSHPDR)* (Figure 3).

In the past, sugar cane estates used hydro wheels to operate mills, but none of these early hydropower plants are in operation today. Several studies have been undertaken to assess the hydropower potential in the country. An analysis carried out in 1981 by the French firm SCET concluded that Grenada has a cumulative potential of at least 7 MW. In 1984, six potential hydropower projects were analysed in a pre-feasibility study at the Great, Marquis and St. Mark's Rivers. In 1991, the British consulting firm MRM Partnership confirmed the hydropower potential of the Great River Upper Basin, including a 720 kW Birchgrove and a 380 kW Belvidere hydropower projects.[11] In 2018, a grant of approximately USD 100,000, most of which financed by the Global Environment Facility (GEF), was approved for a 30 kW hydropower project in Birchgrove, however completion of the construction has not been announced as of yet.[14] Additionally, in 2022, the German Development Corporation (GIZ) was partnering with the Government of Grenada and its water authority, the National Water and Sewage Authority (NAWASA), to bring the possibility of pumps-as-turbines technology to the island, which, if implemented, will generate hydropower in existing water pipes that currently bring potable water from the mountains down to the coasts.[15]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Grenada (in MW)**

Source: *WSHPDR 2019*,[11] *WSHPDR 2016*,[12] *WSHPDR 2013*[13]

SHP development in Grenada has not been explicitly prioritized by the Government further than the general goal to expand renewable energy declared in the Energy Supply Act of 2016. The National Energy Policy of 2011 specifically discusses solar power, wind power and geothermal energy but does not mention hydropower.[16] Nevertheless, any SHP generation development would be granted grid preference under the Energy Supply Act and would be regulated as per the Public Utilities Regulatory Commission Act. Financing for these projects would most likely come from international donors, such as foreign organizations or development banks.[11]

RENEWABLE ENERGY POLICY

The National Energy Policy of 2011 states the importance of transitioning to renewable energy and set the goal to generate 20 per cent of the country's energy from renewable sources by 2020.[16] This goal was made with the idea that geothermal energy would be in operation by then, however, it has still not yet been developed and therefore the goal was not reached. Additionally, in the country's first Nationally Determined Contribution of 2016, a target was set to reach an installed capacity of 15 MW of geothermal energy, 10 MW of solar energy and 2 MW of wind energy by 2025, but the second Nationally Determined Contribution of 2020 recognized that this target will most likely not be met.[17,18]

The national power company, GRENLEC, offers a Renewable Energy Interconnection Programme that allows private owners of solar PV systems to sell the extra energy produced back into the grid. This is a net-billing system where customers receive credit for the value of the amount of fuel that was avoided due to the solar power supplied.[19] Owners of the renewable energy-based generators selling electricity to GRENLEC are remunerated either at a fixed rate of XCD 0.45 (USD 0.17) per kWh or at a variable rate equal to the average fuel price per kWh of the previous year, which for 2022 was XCD 0.37 (USD 0.14) per kWh.[10] As of 2020, over 2.4 MW was connected to the grid from customers in this programme.[5]

BARRIERS AND ENABLERS FOR SMALL HYDRPOWER DEVELOPMENT

The key barriers to SHP development in Grenada include:

- The national focus being on geothermal and solar power resources, with a secondary focus on wind power, while hydropower does not play any role in the country's energy supply planning;
- No incentives or other special framework conditions for hydropower development have been created;
- The country's hydropower potential is poorly investigated;
- The lack of local expertise in hydropower.

The key enabler to SHP development in Grenada is as follows:

- With high dependency on diesel fuel and unmet goals to reach a level of 20 per cent of energy sourced from renewable energy, hydropower can be used to help reach the country's goal.

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Guadeloupe

Oluwatimilehin Paul Olawale-Johnson, International Center on Small Hydro Power (ICSHP)

KEY FACTS

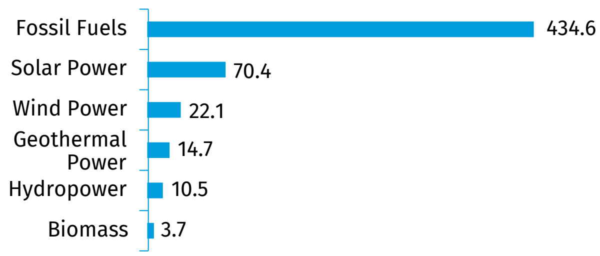
Population	400,020 (2021) [1]
Area	1,690 km^2 [1]
Topography	Composed of the two main islands of Basse-Terre and Grande-Terre, Guadeloupe is an archipelago that also includes multiple smaller islands. The two main islands are joined together only by a few bridges on a narrow sea channel and a mangrove swamp. Guadeloupe is characterized by a volcanic relief, with its highest point measuring 1,467 metres on the Soufriere Volcano.[2]
Climate	The climate is tropical, characterized by humidity and high temperatures all year round. A remarkable stability is observed in monthly temperatures, which may be attributed to *Les Alizés*, the trade winds. There are two main and distinct seasons in Guadeloupe: the rainy season lasting between June and November and the dry season commencing in December and ending in May. Average temperatures in inland and coastal areas differ by only a few degrees Celsius. In inland areas, temperatures are between 19 °C and 27 °C, while on the coast temperatures reach 22–30 °C. The region is affected by hurricanes that most frequently occur in September, but also anytime during the rainy season, between June and November.[3]
Climate Change	With climate change and the progressive sea level rise, the archipelago is highly exposed to coastal risks, particularly given the increasing concentration of population and economic activities along the coast.[4] Climate change is predicted to lead to the deterioration of coastal areas, erosion of beaches and coral beds, increasing likelihood of flooding and water stagnation in coastal plains, which will eventually damage the soil resistance and coastal infrastructures such as sanitation, drinking water, electricity and roads. Average temperatures are expected to increase by 1.6–4.3 °C by 2010 and heavy rains are expected to become 5–10 times more frequent.[5]
Rain Pattern	The average annual precipitation is 1,814 mm. Rainstorms pass very quickly in general and rain showers are likely to occur at any time during the year, not only between June and November. September is considered the wettest month, while February is historically the driest.[6]
Hydrology	The Guadeloupe National Park on the island of Basse-Terre, where most rivers are located, is the main source of water in Guadeloupe.[5] Some of the most important rivers in Basse-Terre are the Lézarde, Moustique, Rose and Petite Rivière à Goyaves. Canal Perrin and Rivière des Coudes are located on Grande-Terre. Grande-Terre and Basse-Terre are separated by the Salt River. Small islands and the dry regions of Grande-Terre are supplied with water through the developed storage capacities and tapped resources.[7,8]

ELECTRICITY SECTOR OVERVIEW

In 2020, the total electricity generation in Guadeloupe was 1,689 GWh.[9] Most of the electricity was generated from fossil fuels such as diesel and coal. Only approximately 23 per cent was from renewable energy sources (Figure 1).

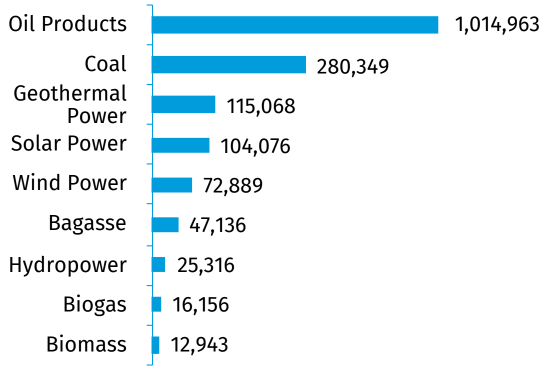
The total installed electricity capacity in Guadeloupe was 556 MW in 2018, with 435 MW from fossil fuel-fired plants and 121 MW from renewable energy sources (Figure 2).[10] Guadeloupe is, thus, highly dependent on fossil fuel generation (coal, diesel and combustion turbines), which account for 80 per cent of the electricity consumed in the archipelago.[11]

Figure 1. **Annual Electricity Generation by Source in Guadeloupe in 2020 (MWh)**



Source: DEAL[9]

Figure 2. **Installed Electricity Capacity by Source in Guadeloupe in 2018 (MW)**



Source: NREL[10]

The Guadeloupe Archipelago is a non-interconnected zone and generates all of its electricity. The islands are connected via submarine cables linked to the network of overhead lines covering Basse-Terre and Grande-Terre.[11]

The Electricity of France (EDF) is the transmission and distribution utility on the archipelago and also operates a significant portion of the country's fossil energy generation. There are also some independent power producers (IPPs), which primarily produce renewable electricity. The Commission for Regulation of Energy (CRE) regulates the electricity sector in Guadeloupe.[12]

Electricity tariff rates in Guadeloupe are defined by the French electricity regulations and are approximately USD 0.19 per kWh.[10,13]

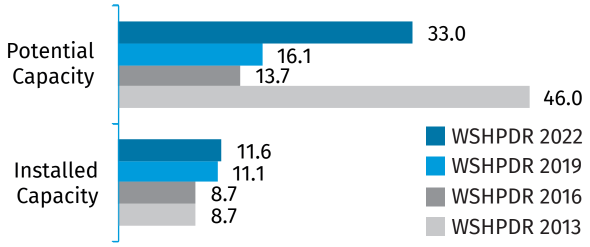
SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) is defined in Guadeloupe as hydropower plants with capacity up to 10 MW. According to the Department of Environment, Planning and Housing (DEAL), Guadeloupe has 16 SHP plants with a total installed capacity of 11.59 MW (Table 1).[14] The existing plants are mainly located in Basse-Terre, due to the combination of available water conditions and suitable topography. These plants are primarily integrated into four irrigation networks and are spread over the Capesterre Belle Eau, Baillif and Vieux-Habitants Rivers. The only plants on Grande-Terre are the Letaye and Gaschet SHP plants.[15]

In 2019 and 2020 SHP plants produced 44 GWh and 25 GWh of electricity, respectively, representing approximately between 2 per cent and 3 per cent of the electricity consumed in the country.[14] The drastic decrease in SHP generation between 2019 and 2020 was due to a 30–40 per cent lower than average precipitation in 2020, which led to the prioritization of other water uses over electricity generation.[16]

Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the SHP installed capacity slightly increased due to access to more accurate data (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Guadeloupe (MW)**



Sources: DEAL,[14] Region Guadeloupe,[15] *WSHPDR 2013*,[17] *WSHPDR 2016*,[18] *WSHPDR 2019*[19]

The SHP potential is estimated to be 33 MW for an average annual generation of 98 GWh. This potential is concentrated in Basse-Terre, with the development potential being limited by the boundaries of the Guadeloupe National Park. The national park stretches across most of Basse-Terre, therefore, power plants may only be sited on its perimeter. Overall, the development of hydropower in Guadeloupe is constrained by many factors, including energy regulations, in particular, environmental regulations, as well as by the high costs associated with land clearing and connection to the grid. Taking these factors into account, it is estimated that only 25 MW of hydropower capacity can be developed under ideal conditions, for a possible annual generation of 75 GWh.[15,20]

Table 1. **List of Installed Small Hydropower Plants in Guadeloupe**

Name	Installed capacity (MW)	Operator	Launch year
La Rose	2.50	VALOREM	2016
Bovis	0.20	VALOREM	2008
Valeau	0.20	VALOREM	2006
Schoeler	0.07	VALOREM	2004
Saint Sauveur	0.07	VALOREM	2003
Clairefontaine	0.20	VALOREM	2002
Gaschet	0.20	VALOREM	2002
Letaye	0.20	VALOREM	2002
Bellevue	0.11	VALOREM	2002
Partiteur 1 & 2	0.57	VALOREM	1995
Bananiers	2.50	EDF	1994
Carbet	4.50	VALOREM	1993
RN2	0.20	VALOREM	–
Dongo	0.07	VALOREM	–

Source: DEAL,[14] VALEMO,[21] Region Guadeloupe[22]

Most SHP plants in Guadeloupe are operated by VALOREM, a renewable energy operator that entered the country's market in 2018. Initially the company was involved in the wind power sector, but in 2019 expanded into hydropower by acquiring 14 SHP plants from Force Hydraulique Antillaise SAS (FHA).[21]

RENEWABLE ENERGY POLICY

In recent years, Guadeloupe has adopted measures for the development of renewable energy sources. As of 2021, its electricity mix consisted of 23 per cent of renewable energy.[8] A range of projects have been developed to size and install renewable power plants in the country.[10] In 2017, the 2016–2023 Multi-Year Energy Programme (PPE) was approved, replacing the Regional Plan for Renewable Energy and the Rational Use of Energy (PRERURE). The PPE aims to reduce final energy consumption by 10 per cent by 2023 and limit the increase in electricity consumption demand to +4 per cent in the same year. It also highlights the objective to achieve a 50 per cent share of renewable energy in final energy consumption, develop 261 MW of additional renewable energy capacity by 2023 (relative to 2015) and achieve energy independence by 2030.[23]

The current technology and the regulatory environment limit the future expansion and upgrades of existing hydropower facilities. While the PPE encourages proposals for enhancing existing production capacities or developing new ones, the PPE is more aimed at strengthening systems to manage energy demand and developing other renewable energy sources, whereas for hydropower no new developments are planned.[17,23]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers to further development of SHP in Guadeloupe are the following:

- Environmental standards are strict and the construction of new SHP plants may be slow to ensure compliance;
- Significant water resources for micro-and small-scale hydropower are located in the National Park, which is a protected area;
- High costs for grid connection and area clearing;
- There is more interest in the development of other renewable energy sources, rather than SHP, as after multiple feasibility studies, it was concluded that solar, geothermal and wind power are the most cost-effective alternatives.

The enabling factors for SHP development in Guadeloupe include:

- The hydropower sector development, including optimization of existing capacities, is actively encouraged in the PPE;
- Guadeloupe has IPP experience in renewable energy project development.

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Haiti

Pierre Kenol Thys, Inter-American Development Bank; and Laura Stamm, International Center on Small Hydro Power (ICSHP)

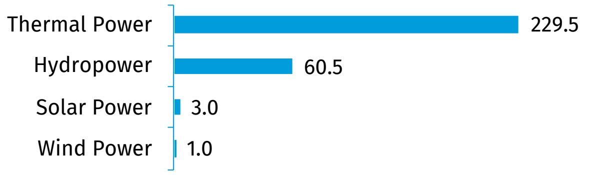
KEY FACTS

Population	11,402,533 (2020)[1]
Area	27,750 km^2 [2]
Topography	The terrain is predominantly rugged with approximately two-thirds of the territory lying at elevations above 490 metres. The coastline is largely irregular with rocky shores and cliffs. The major mountain ranges run in an east-west orientation such as the Northern Massif, the Matheux Mountains that extends into the Trou d'Eau Mountains on its eastern end, and the Massif de la Hotte that extends into the eastern Massif de la Selle. The country's highest peak, Mount La Selle, reaches 2,674 metres and is located in the south-eastern Massif de la Selle. Two minor ranges, the Cahos and Noires Mountains are located in the central region and surround the Central Plateau, a flat region with an average elevation of 300 metres. With a long fault line crossing the southern part of the country and passing just south of the capital city Port-au-Prince, the country is subject to periodic seismic activity.[2]
Climate	Haiti generally has a tropical climate. Average temperatures vary greater between altitudes than throughout the year. Near sea level, temperatures range from 25 °C in January and February to 34–36 °C in July and August. In higher elevations, temperatures average 16 °C and frost can occur during the winter months. [2]
Climate Change	As an island state in the Caribbean, the country's largest climate risks are the rising of sea levels and surges in natural disasters. In the upcoming decades, an increase in the prevalence and intensity of hurricanes and tropical storms is anticipated. At the same time, overall rainfall is expected to decrease, as it already has been decreasing at a rate of 5 mm per month per decade since 1960. Additional concerns are that the tendencies of coastal erosion, landslides and droughts will most likely intensify.[3,4]
Rain Pattern	Annual rainfall varies between regions and elevation. The northern and eastern mountainous regions experience the most rainfall with an average of 1,200 mm per year. Western regions with low elevations and La Gonâve Island receive closer to 550 mm per year. Generally, the wet season is between May and November, but some regions experience a minor dry season between June and August.[4]
Hydrology	The Artibonite is the longest river on the island at 280 kilometres. It begins in the Northern Massif (the Cordillera Central) in the western Dominican Republic and flows south-westwards along the border with Haiti, draining into the Gulf of La Gonâve. Its tributaries flow eastwards and southwards through the Central Plateau. In the east, the Artibonite was impounded as Lake Péligre. Most other rivers are short and not navigable.[2]

ELECTRICITY SECTOR OVERVIEW

As of 2020, the total installed capacity in Haiti was reported to be 294 MW but no accurate official data are available. Approximately 78 per cent of the total, or 229.5 MW, was from thermal power plants, over 20 per cent, or 60.5 MW, was from hydropower and the remaining 2 per cent was from 3 MW of solar power and 1 MW of wind power (Figure 1).[5] A large majority of the installed capacity serves the country's capital and metropolitan area including the three largest thermal power plants — Carrefour I (50 MW), Carrefour II (34 MW) and E-Power (34 MW) — and the largest hydropower plant, Péligre (54 MW).[6,7] Another major thermal power plant is planned to be constructed in Carrefour and the large Varreux thermal power plant (68 MW) is in need of renovation. While these constructions take place, a Turkish company has been approved to install two barges, or floating power plants, with a combined capacity of 115 MW, near Varreux and Cap-Haitien.[8] Additionally, in 2021, funding was secured to be provided by the United States Agency for International Development (USAID) and the Inter-American Development Bank (IADB) to construct two new solar power plants in Carrefour with capacities of 8 MW and 4 MW.[9]

Figure 1. **Installed Electricity Capacity by Source in Haiti in 2020 (MW)**



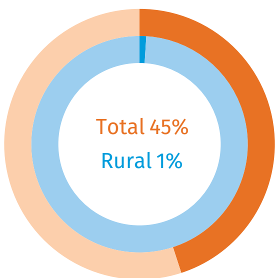
Source: CCREEE[5]

Due to infrastructural deterioration and technical inefficiencies, the actual available capacity is lower than what is installed and much of what is generated is lost. Total electricity generated in Haiti in 2020 was 2,199 GWh. Of this, approximately 380 GWh was sold and the remaining 1,319 GWh, almost 60 per cent, was considered lost.[5] This is due to widespread inefficiencies, and also to illegal connections to the grid that are not metered and, therefore, unbilled.[10]

Many households and businesses in Haiti generate their own electricity, most commonly with diesel units. While some use the generators as a back-up during blackouts, many have disconnected completely from the grid and fully rely on their own generators. The total capacity of electricity self-generated off the grid is unknown, but it exceeds the electricity generated on-grid. In 2017, it was estimated that over 75 per cent of total electricity generated within the country was from self-generation.[10]

In 2019, the overall electrification rate in Haiti was approximately 45 per cent and in rural areas it was just 1 per cent (Figure 2), the lowest in the western hemisphere.[11] Additionally, for the people that do have access to electricity, it is often only for some hours of the day rather than a 24-hour connection.

Figure 2. **Electrification Rate in Haiti in 2019 (%)**



Source: World Bank[11]

The electricity grid in Haiti consists of a number of isolated grids. Outside of the metropolitan area, there are 10 regional grids that serve the larger towns and nearby areas, as well as approximately 30 village-level grids.[12]

The principal company in the sector is Electricity of Haiti (EDH). By a decree of 20 August 1989 EDH was granted monopoly rights to generate, transmit, distribute and sell electricity across the country, but also allowed to outsource electricity production to independent power producers (IPPs). Another decree issued in 2006 allowed local communities not served by EDH to contract independent enterprises to provide electricity services, which fostered the development of micro-grids in the country. Historically there was no regulatory agency overseeing EDH activities until the National Authority for the Regulation of the Electricity Sector (ANARSE) was established in 2016, whose purpose is to guide the development of the electricity sector, in particular, through increasing the private sector involvement.[12]

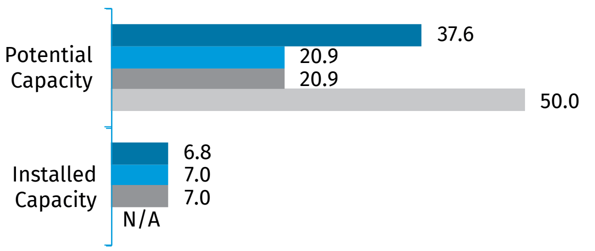
Electricity tariffs vary by consumer type. For residential customers the total tariff is 0.28 USD/kWh, for commercial customers it is 0.37 USD/kWh, for industrial customers it is 0.39 USD/kWh and for street lighting it is 0.37 USD/kWh.[5]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in Haiti. For the purposes of this chapter, all hydropower plants up to 10 MW will be classified as SHP.

In 2018, the total installed SHP capacity up to 10 MW in Haiti was 6.81 MW (Table 1).[13] Considering additional potential sites found in feasibility studies, total SHP potential in Haiti is 37.56 MW. Compared to the results of *the World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity has slightly decreased and potential capacity has increased, both due to new available data (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Haiti (MW)**



Sources: Mitchell,[13] *WSHPDR 2019*,[14] *WSHPDR 2016*,[15] *WSHPDR 2013*[16]

There are currently eight hydropower plants in Haiti, all of which are operated by EDH. Seven plants are small-scale, while the only large-scale hydropower plant, the 54 MW Péligre plant, is the oldest hydropower plant in the country. Its first turbine out of three was commissioned in 1971 and it took three more years to complete the other two turbines. The most recently commissioned hydropower plant is an 11 kW micro-hydropower plant installed in the small community called Magazen, in the Nord-Est province, in 2016. This plant supplies electricity to 74 families.[14]

Over the years, the available capacity of the hydropower plants has decreased due to ageing equipment and lack of maintenance. In July 2018, with more than USD 100 million provided by the Inter-American Development Bank (IDB), the KfW Development bank and the Organization of the Petroleum Exporting Countries (OPEC) Fund for International Development, the biggest source of renewable energy in the country, the Péligre hydropower plant, regained its initial capacity of 54 MW.[14]

Table 1. **List of Existing Small Hydropower Plants in Haiti**

Name	*Location (region)*	*Installed capacity (MW)*
Drouet	Le Grand Nord	2.50
Saut Mathurine	Le Grand Sud	1.60
Délugé	Le Grand Nord	1.10
Caracol	Le Grand Nord	0.80
Gaillard	Le Grand Sud	0.50
Onde-Verte	Centre Ouest	0.30
Magazen	Nord-Est	0.01
Total		**6.81**

Source: Mitchell[13]

Table 2. **List of Selected Hydropower Potential Sites in Haiti**

Name	*Location (region)*	*Capacity (MW)*
Guayamouc GU3.5	Centre	3.41
Roche Plate	Centre	2.57
Grande Anse BG15.4	Grand'Anse	2.48
Guayamouc GU25.7	Centre	2.13
Trois Rivieres TR28	Nord-Ouest	1.78
La Theme LA1.6	Centre	1.35
Grand Anse GA4.1	Grande'Anse	1.21
Deluge-Lanzac	Artibonite	1.18
Momance	Ouest	1.12
Grand Anse BD8.6	Grande'Anse	1.06
Grand Anse GA35.4	Grande'Anse	0.97
Cazale 1	Ouest	0.89
Samana	Centre	0.78
Fer a Cheval FC8.5	Centre	0.74
Trois Rivieres TR78	Artibonite	0.73
Grand Riviere du Nord GN30.3	Nord	0.72
Riviere Grise G31.0	Ouest	0.72
Pichon 2	Sud-Est	0.68
Saut d'Eau	Centre	0.67
Bouyaha B11	Centre	0.63

Source: Mitchell[13]

In addition to the existing SHP capacities, there are a significant number of sites identified with SHP potential that can be harnessed. According to the most recent feasibility study carried out by the Ministry of Public Works, Transport and Communication (MTPTC), there are 36 potential SHP sites ranging in capacity from 0.13 MW to 3.41 MW and with a combined untapped potential of 30.75 MW. The 20 potential sites with the largest capacities are shown in Table 2.[13]

RENEWABLE ENERGY POLICY

The development of the country's energy sector follows the Strategic National Plan for the Development of Haiti (SPDH), which envisages improving on-grid electricity services in urban areas and surroundings and supporting off-grid electrification in rural areas. The National Development Plan for the Energy Sector (2007–2017) recommended the promotion of renewable energy sources (wind power, solar power, biofuels) and the creation of an additional capacity from renewable energy sources of some 40 MW.[17] The plan also included objectives to increase electricity service for customers to have access 12 hours per day, to improve the regulatory role of the state and to create an environment that attracted foreign and domestic investment in the sector.[18] However, the 2010 earthquake, which damaged or destroyed a great number of electricity facilities, rendered the plan out-of-date and it has not been updated yet.

Nonetheless, the Government remains committed to the development of renewable energy sources in the country. In the country's First Nationally Determined Contribution of 2015, it set renewable energy goals for 2020 and 2030. By 2020, the goal was to install additional 37.5 MW in hydropower, which has not been achieved as of 2022. Conditional goals for 2030 include installing 20 MW of biomass, 30 MW of solar power, 50 MW of wind power and to add an additional 60 MW of hydropower, so that 47 per cent of the country's electricity sector is generated using renewable energy.[19]

In the country's 2017–2018 budget, measures for the promotion of renewable energy projects, particularly solar power, were introduced, including the elimination of import tariffs and duties on solar equipment. One of the objectives for the 2017–2018 fiscal year was to pursue the installation of solar power facilities across the country, particularly in areas with limited infrastructure, with a minimum of one installation per community.[20]

In 2017, the World Bank approved two grants for a total amount of USD 35 million, which will fund two projects in Haiti, Renewable Energy For All and Haiti Modern Energy Services For All. The projects aim to improve access to electricity and to scale up investments in renewable energy in underserved rural and urban areas. In particular, they will help:

- Improve the environment for private investment in renewable energy;
- Expand the access for rural households through leveraged investments in micro- and mini-grids and village level systems;

- Strengthen the capacity of local institutions and develop awareness of local communities on how to use renewable energy;
- Finance private operators, non-governmental and community organizations to provide solar lanterns and individual and home-based solar systems.[21]

As per the Decree on the Management of Environment and the Regulation of Citizen Conduct for Sustainable Development of 2005, all policies, plans and projects that would have a negative impact on the environment are subject to an environmental impact assessment (EIA). It also provides legal framework for various levels of government and their responsibilities towards the environment.[18]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The barriers hindering the development of SHP in Haiti include:

- Absence of a single decision-making authority and lack of coordination among government agencies and ministries;
- Absence of a legal framework aiming to facilitate private investment and technical rules facilitating connection between local grids;
- Limited funds for the construction of hydropower plants. The initial investment for the construction of a plant is considerably high, therefore, developers can be reluctant to invest;
- Lack of transmission infrastructure outside the capital metropolitan area and the cost of electricity system development is high.[14]

The key enablers for development of SHP in Haiti include:

- Most of the SHP potential is untapped and many sites have already been identified with their respective capacities;
- Being the least electrified country of the region, the necessity of developing power plants and supplying electricity is crucial, especially in rural or remote areas.

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Jamaica

Kimberly Lyon, World Bank

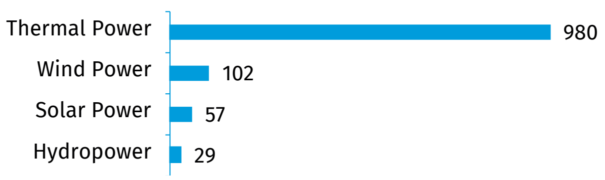
KEY FACTS

Population	2,734,092 (2019)[1]
Area	10,991 km^2[2]
Topography	The terrain of Jamaica is mostly mountainous, with a narrow, discontinuous coastal plain. The highest point is the Blue Mountain Peak at 2,256 metres above sea level and the lowest point is the Caribbean Sea.[2]
Climate	Jamaica has a tropical climate, which is influenced by the North-East Trade Winds, with a temperate climate in the interior. Average temperatures historically range from 24 °C to 27°C, varying with elevation and proximity to the coast.[3]
Climate Change	Jamaica has not experienced a significant increase or decrease in overall rainfall, but total annual precipitation is projected to decline starting in the mid-2020s due to climate change, with an onset of a more pronounced drying trend in the mid-2030s. The country is also grappling with the consequences of sea level rise. Current trends are projected to continue with possible temperature increases of 0.82-3.09 °C by the end of the century.[3]
Rain Pattern	Jamaica has a bimodal rainfall pattern, which translates into a dry season lasting from December to March and a rainy season from April to November. The mountainous interior generally receives annual rainfall in excess of 1,700 mm and the eastern part of the island receives up to 5,000 mm or more. The northern and southern coasts are significantly drier with the plains of the south receiving on average 1,000 mm of precipitation or less.[3]
Hydrology	The water resources of Jamaica consist of groundwater, captured in both limestone and alluvial aquifers, and surface water from over 100 rivers and streams. The central mountain ranges divide the catchment areas for rivers, which drain either to the northern or to the southern coasts. The island is divided into 10 hydrological zones. The limestone and alluvium aquifers provide 84 per cent of the country's freshwater resources, while the remaining 16 per cent is provided by surface water. The exploitable water resource is estimated at 3,930 MCM/year.[4,5] The main rivers include the Black River, Great River, Rio Cobre, Rio Grande, Rio Minho, Wagwater River and Yallahs River.[6]

ELECTRICITY SECTOR OVERVIEW

Electricity generation in Jamaica is dominated by fossil fuels with a growing contribution from renewable energy. At the end of 2019, Jamaica had 1,198 MW of available generation capacity, which generated 4,430 GWh of power (Figure 1). Of this total, the Jamaica Public Service (JPS) generated 1,229 GWh from steam and diesel, 1,055 GWh from gas and 155.2 GWh from small hydropower (SHP). Additionally, JPS purchased a further 1,990.3 GWh from independent power producers (IPPs) powered by wind power, solar power and oil.[7,8]

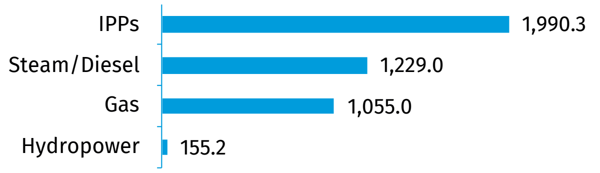
Figure 1. **Annual Electricity Generation by Source in Jamaica in 2019 (GWh)**



Source: JPS[7,8]

By the end of 2020, with the retirement of older units, there was 1,168 MW of available generation capacity.[7,9] Renewable sources made up almost 18.5 per cent of existing capacity and the remaining 81.5 per cent was fossil fuel-based, specifically, liquefied natural gas (LNG), heavy fuel oil (HFO) and automotive diesel oil. In 2020, the national power utility JPS continued with its plans to retire older fossil fuel plants and convert remaining steam generation assets to run on LNG. Thus, at the end of 2019, the island had 1,010 MW of thermal power capacity, while in 2020 this figure was reduced to 980 MW.[7] Wind power is the largest source of renewable energy at 102 MW, followed by solar power and hydropower at 57 MW and 29 MW, respectively (Figure 2).[10]

Figure 2. **Installed Electricity Capacity by Source in Jamaica in 2020 (MW)**



Source: JPS,[7] MSET[10]

The share of the population in 2017 with access to electricity stood at 94 per cent nationally with 98 per cent in the Kingston Metropolitan Area, 93 per cent in other towns and 91 per cent in rural areas. The vast majority of households get their electricity from the grid with only 0.1 per cent getting electricity from off-grid solar.[11] According to the World Bank, in 2019 over 99 per cent of the country's population had access to electricity, including 100 per cent in urban areas and almost 99 in rural areas.[12,13,14]

JPS is a vertically integrated power utility. It fully controls transmission and distribution of electricity on the island and owns 47 per cent of the power generation capacity, purchasing the remainder of its supplied electricity from IPPs, including Jamaica Energy Partners (JEP), Jamaica Private Power Company (JPPC), Jamalco and Wigton Wind Farm. The JPS was fully state-owned until 2001 when the Government of Jamaica divested 80 per cent of its shares to foreign investors. A small group of individuals hold 0.1 per cent of the JPS shares. In 2019, the Government announced its intention to list its remaining 19.9 per cent interest on the stock market. As of early 2021, the Government still retained its shares in the JPS.[9,15]

New generation capacity is added to the network through a competitive process and over 2015–2020, 117.3 MW of renewable energy capacity (wind power and solar photovoltaics (PV)) were added to the grid. The country's 2030 target for renewable energy penetration is 20 per cent of the total energy mix and 30 per cent of electricity generation.[10]

Electricity demand is expected to steadily grow over the coming decades with a forecasted annual growth rate of 1.3–1.6 per cent until 2035. By 2035, demand is projected to reach 5,865 GWh. Demand growth for both residential and commercial customers is expected to be driven largely by overall economic growth. JPS's load factor is assumed to remain constant at 78 per cent.[10]

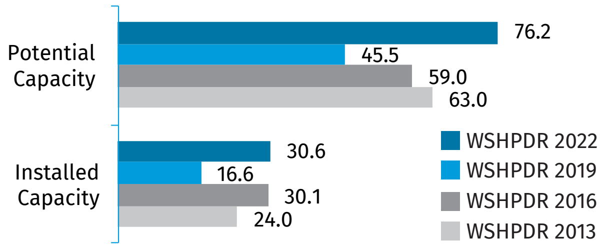
The average electricity tariff in Jamaica has trended downwards in recent years from 0.35 USD/kWh in 2013 to approximately USD0.27/kWh in 2020.[16,17] Nonetheless, it remains high due to the country's reliance on older, less efficient HFO generators that run on costly imported fuel as well as high losses in the transmission and distribution network. Because of its dependence on fuel imports, Jamaica remains very exposed to international price fluctuations. These factors, together with meeting the climate commitments, underpin the Government of Jamaica's strategy to increase the penetration of renewable energy in the energy mix and to transition the fleet of oil- and diesel-powered assets to run on LNG.[10,16]

The electricity sector is regulated by a multi-sector regulator, the Office of Utilities Regulation, which determines the electricity tariffs and oversees the net billing programme aimed at increasing renewable energy generation by small-scale intermittent sources (wind power and solar PV). With the rise of self-generation and other developments in the electricity sector, including the introduction of electric vehicles and the commissioning of a hybrid energy storage system, several new categories of tariffs were introduced in the JPS tariff determination for the period up to 2024. These include a distributed energy resource (DER) tariff for self-generation customers, an electrical vehicle tariff and a wheeling tariff.[17]

SMALL HYDROPOWER SECTOR OVERVIEW

SHP is not defined in Jamaican law or policy, but the threshold of 10 MW is commonly used by energy sector professionals and Government officials, with facilities below 1 MW considered mini-hydropower. All existing hydropower facilities and all but one proposed facility — the Mahogany Vale site — are under 10 MW.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Jamaica (MW)**



Source: JPS,[7] MSET,[10] *WSHPDR 2019*,[19] *WSHPDR 2013*,[20] *WSHPDR 2016*[21]

There are eight existing hydropower plants in Jamaica (Table 1), all owned and operated by JPS. Together, these have an installed capacity of 30.6 MW and an annual generation of 152,612 MWh.[7,10] The existing hydropower fleet is fairly old with several facilities constructed before the country's independence in 1962. However, most facilities have been rehabilitated since the 1990s.[18] The most recent addition to the fleet is an extension project with a second powerhouse at the Maggoty Falls facility, which came online in 2014. The original Maggoty Falls facility was commissioned in 1966. Thus, no new SHP plants have been commissioned in Jamaica since the *World Small Hydropower Development Report (WSHPDR) 2019*. The change in the reported installed capacity is due to the fact that in the previous edition the

Maggoty Falls plants were counted as one and, hence, were excluded from the total due to their combined capacity exceeding 10 MW. However, the two Maggoty Falls plants have separate powerhouses and are treated by JPS as separate projects. The potential capacity estimate has also increased compared to the previous edition, based on new data on available sites (Figure 3).

Table 1. List of Existing Small Hydropower Plants in Jamaica

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Maggoty Falls Extension B	St. Elizabeth	7.2	88.4	Run-of-river	JPS	2014
Rio Bueno B	Trelawny	1.1	N/A	Run-of-river	JPS	1989
Ram's Horn	St. Andrew	0.6	N/A	Run-of-river	JPS	1989
Constant Spring	St. Andrew	0.8	N/A	Run-of-river	JPS	1989
Maggoty Falls A	St. Elizabeth	6.0	88.4	Run-of-river	JPS	1966
Lower White River	St. Ann	4.8	115.2	Run-of-river	JPS	1952
Roaring River	St. Ann	3.8	152.4	Run-of-river	JPS	1949
Rio Bueno A	Trelawny	2.5	89.9	Run-of-river	JPS	1949
Upper White River	St. Ann	3.8	70.1	Run-of-river	JPS	1945

Source: JPS,[7] USACE[22]

Thirteen potential SHP sites have been studied for full-scale feasibility and deemed feasible. One site, Morgan's River, was studied at the pre-feasibility level but did not progress to full feasibility. The Rio Cobre (Angels) site is located at an existing irrigation weir operated by the National Irrigation Commission Ltd.[23,24,25] In the *WSHPDR 2019*, the 0.8 MW Dry River site was included in the list of potential SHP projects, however, in the current edition it has been removed as it was determined as not viable in a 2013 analysis by the Ministry of Science, Technology, Energy and Mining. Furthermore, the potential reservoir-based project Mahogany Vale with an estimated potential capacity of 50 MW has been foregone in favour of six small run-of-river projects in the same basin: Spanish River, Negro River, Yallahs River, Green River, Back Rio Grande and Swift River. The Back Rio Grande site (with a potential of 10–28 MW) appears to have been foregone in favour of four smaller projects: Swift River, Rio Grande 1, Rio Grande 2 and Back Rio Grande 2. Table 2 shows the available potential SHP sites.

Compared to other countries, the hydropower potential of Jamaica is considered low.[29] Based on the existing installed capacity and the identified potential sites, the country's economic SHP potential capacity and generation stand at 76.2 MW and 347 GWh per annum, respectively. The technical potential capacity and generation are estimated at over 80 MW and 600 GWh per annum, respectively.[30,31]

All the potential sites identified have been studied with a view to connecting them to the existing transmission and distribution network. There is little scope for off-grid SHP investments, but the law permits the development of micro-grids for rural electrification if JPS waives its right to provide service in a particular geography.[32]

Table 2. List of Potential Small Hydropower Projects in Jamaica

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site*
Great River	St. James	8.0	N/A	New
Spanish River	Portland	7.8	N/A	New
Martha Brae	Trelawny	4.4	N/A	New
Back Rio Grande 2	Portland	4.0	83.13	New
Swift River	Portland	2.9	54.9	New
Green River	St. Thomas	2.8	224.8	New
Morgan's River*	St. Thomas	2.7	N/A	New
Yallahs River	St. Thomas	2.6	N/A	New
Negro River	St. Thomas	2.3	N/A	New
Laughlands Great River	St. Ann	2.0	N/A	New
Wild Cane	St. Thomas	1.9	559.6	New
Rio Cobre (Bog Walk)	St. Catherine	1.5	N/A	New
Rio Cobre (Angels)	St. Catherine	1.0	7.8	Refurbishment
Rio Grande 1	Portland	0.9	9	New
Rio Grande 2	Portland	0.8	13.4	New

Source: MSET,[10,26] USACE,[22] Makhijani,[27] Williams[28]

Note: The project did not progress to the full feasibility study after the pre-feasibility study.

Efforts to promote SHP increased in the 2010s with the commissioning of pre-feasibility and feasibility studies for 11 sites ranging from 0.8 MW to 7.8 MW. There were plans to develop business plans for six of these sites to support their promotion to potential investors. However, in 2020, the Petroleum Corporation of Jamaica, the public entity responsible for energy planning and promotion, was dissolved and these responsibilities were transferred to the Ministry of Science, Energy and Technology.[33,34] The Ministry's latest Strategic Plan, covering the period of 2021–2025, affirms the Government's commitment to promoting renewable energy investments, including in SHP.[35]

The Government has demonstrated a preference for smaller hydropower projects over larger projects, considering potential social and environmental impacts as well as impacts on high-value tourism assets. This is evident from the decisions to pursue detailed investigation of multiple smaller projects in locations where there is potential for larger plants, specifically the proposed Mahogany Vale and Back Rio Grande projects.

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

There are several SHP projects available for investment above 1 MW that the Government intends to develop business plans for with the intention of investment promotion (Table 3).[33]

Table 3. **List of Selected Projects for Small Hydropower Projects Available for Development in Jamaica**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site*
Spanish River	Portland	7.8	N/A	New
Martha Brae	Trelawny	4.4	N/A	New
Swift River	Portland	2.9	54.9	New
Laughlands Great River	St. Ann	2.0	N/A	New

Source: GoJE[33]

RENEWABLE ENERGY POLICY

Jamaica has a National Energy Policy covering the period from 2009 to 2030, which is aligned with the country's National Development Plan, Vision 2030. The aim of the plan is to create and advance a modern, efficient, diversified and environmentally sustainable energy sector, focused on diversification of the energy base towards indigenous sources of energy and clean technologies. The National Energy Policy is technology-neutral and promotes all renewable energy sources, including solar power, wind power, hydropower and biofuels.[18]

In 2020, the Government completed its Integrated Resource Plan (IRP), a 20-year roadmap for the country's electricity investment landscape. The IRP envisions 32 per cent of electricity generation by 2030 and 50 per cent by 2037 to be met with renewable energy sources. A total of USD 2.8 billion of investment is anticipated over the life of the IRP.[10]

The IRP also discusses the evolution of the national grid to accommodate higher integration of variable renewable energy sources with the ultimate goal of distributed markets for energy. However, the planning process for integrated distribution is only nascent, and the Government anticipates investing in further study and improvement of the integrated distribution planning framework. At present, any new investments in SHP would take the form of an IPP with a power purchase agreement with the JPS, the single buyer whose licence obligates it to purchase electricity from IPPs and persons with net billing arrangements.[32]

Over the planning horizon of the IRP, 485 MW of private power capacity has been identified for retirement and replacement, coinciding with their power purchase agreement expiration. Most of these are HFO-fuelled and JPS has a "right of first refusal" to do these replacements if it can be done more cheaply than by the proposed developer.[10] For JPS, the current allowed pre-tax weighted average cost of capital is set at 13.22 percent and for IPPs it is 11.16 per cent. At present, there are no feed-in tariffs, but the law empowers the Ministry with responsibility for energy, in consultation with the Office of Utilities Regulation, to set feed-in tariffs. There are no differentiated electricity prices based on technology or location.[32]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

According to the IRP, Jamaica is targeting 74 MW of new capacity to come from hydropower, waste-to-energy and/or biomass by the year 2025, increasing the share of hydropower in the generation mix from 2.8 per cent in 2020 to 4.4 per cent in 2037.[10]

All recent renewable energy investments to date have been made either fully by, or with significant participation of, the private sector, hence, it is not likely that the feasible potential SHP sites will be developed in the near term without a private sponsor. As JPS has indicated, it is not interested in pursuing further SHP developments and the Government will be targeting other local or foreign investors to implement these projects.[36]

New SHP projects would be governed by the same legislation and regulations as other energy technologies. There are no provisions in the Electricity Act specific to hydropower of any size. The licensing process for SHP involves securing the necessary land access rights; environmental permits issued by the National Environment and Planning Agency; a licence from the Water Resources Authority to use surface water; a power purchase agreement with JPS; a permit for interconnection, issued by the Office of Utilities Regulation; as well as permits from municipalities in which the generation assets would be located.[10,27]

COST OF SMALL HYDROPOWER DEVELOPMENT

A 2013 study by the Government indicated an average investment cost for SHP at USD 3.5 million per MW installed.[26] Investment costs of six recently studied SHP sites showed an average estimated investment cost of USD 4 million per MW installed or USD 1.28 million per GWh of energy produced. The most recently implemented project, the Maggotty Falls extension was completed in 2014 with an investment cost USD 36 million, which corresponds to approximately USD 5 million per MW installed.[37]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The IRP indicates that the Government intends to analyze and develop incentives for SHP, however, such incentives have not been specified at this time. Jamaica has a vibrant financial sector, including a growing equities market and several commercial banking options more generally. There have been initiatives in past years, supported by international partners such as the World Bank, to incentivize renewable energy investments through credit lines.[38] Commercial banks have also made lower-interest loans available to small and medium enterprises and households for renewable energy investments. Several of the recent renewable energy installations have been made by overseas investors, qualifying for financing from foundations as well as development financing from their Governments.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The intensity and frequency of extreme rainfall events has shown an increasing trend over the last 70 years. While the whole island has experienced a small increase in total annual rainfall, variability has also increased with more consecutive wet days and dry days and more days recording extreme rainfall values. Portland, where several potential SHP sites are located, and Westmoreland have experienced the largest changes. Going forward, climate models project that average rainfall will decrease in Jamaica with a drying trend that will begin affecting the island in the mid-2020s. The island is projected to be up to 4 per cent drier by the 2030s and up to 10 per cent drier by the 2050s.[3] This will negatively impact river flows and decrease hydropower generation. Climate change and longer droughts are also expected to contribute to increased energy demand, though projections for energy demand are still largely driven by economic growth assumptions. All existing and proposed hydropower sites are run-of-river and thus have no inter-seasonal or inter-annual storage to help manage variability in flows. Future investments, particularly on the island's major rivers, will need to take into account the expected increase in extreme rainfall events.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There has been very little activity in the SHP sector since the last set of Government-developed projects in the 1980s. Driven by efforts to lower the cost of electricity and transition the portfolio towards low-carbon indigenous sources of electricity, there has been a renewed interest in SHP development with new and updated studies having been completed in recent years.

The main barriers to SHP development in Jamaica are:

- Significant capital costs, which often exceed those for commercial-scale solar PV and wind power, and licensing requirements that involve a wider range of actors and regulators such as for the acquisition of land and water rights.
- Hydropower is widely perceived by sectoral actors as being very technically complex. The current sole operator of SHP assets in Jamaica is also not interested in further SHP development, instead favouring larger capacity installations with other technologies.
- Much of the knowledge of SHP development and operation is concentrated with JPS as the sole operator of SHP currently. Due to the limited activity in the sector over several decades, local contractors have virtually no experience in this specialized area. The island is heavily dependent on international engineers and consultants for SHP studies.
- Natural hydrologic variability. Many potential projects are located in the rainiest parts of the island, where the floods are so significant as to require significant infrastructure for safe control of releases.
- Disruptions in renewable energy planning and promotion. With the dissolution of the entity primarily responsible for energy planning in 2020 and the transfer of these responsibilities to the Ministry, activities aimed at promoting SHP development have been delayed or altered, including the development of business plans for selected SHP sites.

Nonetheless, in recent years, the enabling environment for SHP has become more favourable:

- The Government has invested considerably in new technical studies for SHP with the intention to develop business plans to support the promotion of selected sites as well as to develop an incentive structure to attract investors. Policy directives heavily favour indigenous renewable energy technologies, including SHP.
- The energy market of Jamaica is becoming more liberalized with the introduction of the 2015 Electricity Act (replacing the previous law enacted more than 125 years ago) and new licence structures.
- The Government has ambitious plans to modernize the energy system and significant investments in grid modernization have already been made by JPS.

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Puerto Rico

Davy Rutajoga, International Centre on Small Hydro Power (ICSHP)

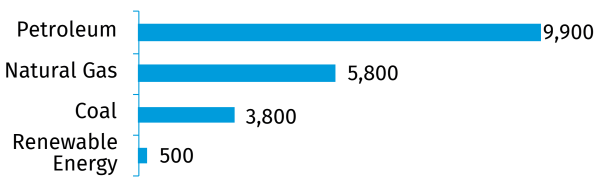
KEY FACTS

Population	3,193,694 (est. 2019)[1]
Area	8,870 km^2 [2]
Topography	Puerto Rico can be split into three physiographic zones. The mountainous interior area is formed by the Cordillera Central, the central mountain chain that transects the island from east to west. The highest point is Cerro de Punta at 1,338 metres above sea level. The second zone is the coastal lowlands that extend 10–19 kilometres inwards in the north and south. Finally, the karst region, consisting of formations of rugged volcanic rock, extends into the north of the island.[3]
Climate	The climate of Puerto Rico is tropical rainforest and temperatures throughout the year are warm to hot, between 22 °C and 25 °C. The temperatures in the southern coast are the warmest and a few degrees higher than in the north. In the central interior mountains, the temperatures are cooler than in the rest of the island.[4]
Climate Change	The 2017 Hurricane María, proven to have the greatest recorded 24-hour rainfall intensity in Puerto Rico since 1898, is among the extreme climatic events of the 2017 Atlantic Hurricane Season that can be attributed to climate change.[5] The subsequent increase in annual precipitations and rainfall intensity placed Puerto Rico first on the 2020 Global Climate Risk Index.[5] The Puerto Rico Climate Change Council reported a rise in average temperatures on the island as well as a rise in sea level and salinity of the ocean.[6] This represents a risk to the island's infrastructure as an estimated 25 per cent of it is located in coastal areas qualified as "easily flooded areas".[7] In particular, all thermal power plants on the island are located in the risky areas.[6]
Rain Pattern	The wettest month in Puerto Rico is August, with 180 mm of rain. Average rainfall varies across the island, ranging from 745 mm in the southern Isle of Maguey to 4,346 mm at Pico Del Este in the east. There is rainfall throughout the year, but it doubles from April to November, whereas the period between December and March is considered to be the driest.[8]
Hydrology	Puerto Rico has 224 rivers, with the main rivers draining the northern and southern areas. Due to the country's topography, there are no long rivers or large lakes.[7] The longest river that flows to the northern coast is the Grande de Arecibo. Other rivers include the La Plata, Cibuco, Loiza, Bayamon and Grande de Anasco.[3] Approximately 67 per cent of the surface drainage is from the central mountain ranges to the northern coast.[9]

ELECTRICITY SECTOR OVERVIEW

The main sources of energy in Puerto Rico are petroleum, natural gas and coal. In 2020, the total installed capacity was estimated at 5,839 MW, with 5,722.2 MW from fossil fuels and approximately 116.8 MW from renewable energy sources.[10] The total electricity generation of the island in 2020 was estimated at 20,000 GWh, with almost 50 per cent coming from petroleum, 29 per cent from natural gas, 19 per cent from coal and less than 3 per cent from renewable energy sources (Figure 1).[11] Average annual hydropower generation is estimated at 15.6 GWh. The natural gas is almost entirely imported as liquefied natural gas and the island has no proved reserves of crude oil or coal, both of which it imports from Colombia.[8]

Figure 1. **Annual Electricity Generation by Source in Puerto Rico in 2020 (GWh)**



Source: EIA[11]

Electricity in Puerto Rico is supplied mainly by the state-owned entity the Puerto Rico Electric Power Authority (PREPA). Average electricity tariffs for the three main groups of consumers are listed in Table 1.

Table 1. **Average Electricity Tariffs in Puerto Rico**

Type of consumer	*Average electricity tariff (USD/kWh)*
Residential	0.2326
Commercial	0.2594
Industrial	0.2288

Source: EIA[11]

In 2019–2021, the island was affected by a series of earthquakes, which culminated in a 6.4 magnitude earthquake that led to power outages by damaging electrical infrastructure. The aftershocks, estimated to recur for years after the earthquake, left two thirds of the population without power by considerably damaging the two largest power plants in Puerto Rico (EcoEléctrica and Costa Sur). As a consequence of the damage to these two natural gas-fired power plants, Puerto Rico had to shift its generation mix to rely more on petroleum, which went up to almost 50 per cent of the generation mix in 2020 from 35 per cent the previous year. Concomitantly, natural gas generation decreased to 20 per cent from 43 per cent in 2019 (Figure 2). Renewable energy generation was relatively unaffected by the earthquakes and remained stable. Power has been restored since and the island maintains an electrification rate of 100 per cent.[11]

The 2017 hurricanes damaged electrical infrastructure and led to PREPA privatizing its electricity transmission and distribution systems, as well as selling off some of its generation assets to avoid bankruptcy. The transmission and distribution systems have been operated by LUMA Energy, a private company, since June 2020.[11]

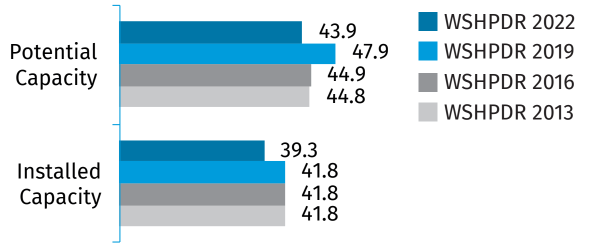
To strengthen the grid's resilience and avoid power outages, such as the ones the island experienced in the aftermath of the hurricanes of 2017, the Puerto Rico Energy Bureau issued its revised Integrated Resource Plan. Jointly with the plan, the Puerto Rico Energy Public Policy Act of 2019 (or Act No. 17 of 2019) outlines the country's commitment to sourcing 40 per cent of its electricity from renewable sources by 2025, eliminating coal-fired generation by 2028 and transitioning to 100 per cent renewable energy by 2050.[12,13]

SMALL HYDROPOWER SECTOR OVERVIEW

This chapter considers small hydropower (SHP) as plants with a capacity of up to 10 MW. There are seven SHP plants on the island with an aggregated capacity of 39.3 MW and an annual generation of 15.6 GWh. These are the 8.0 MW Yauco 2, 8.6 MW Toro Negro 1, 1.9 MW Toro Negro 2, 7.2 MW Garzas 1, 5.0 MW Garzas 2, 5.0 MW Rio Blanco and 3.6 MW Caonillas 2. However, four of these plants were inactive as of June 2021: Toro Negro 2 was offline awaiting testing, Garzas 2 was offline due to a faulty transmission line connecting it to the grid, Rio Blanco was offline awaiting replacement of the penstock and Caonillas 2 has been inactive since 1998 due to flooding from Hurricane Georges. This reduces the available capacity to 23.8 MW (Table 2).[14] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity decreased due to the exclusion from the total of the inoperative Patillas plant (Figure 2).

The SHP sector of Puerto Rico has a potential capacity of 43.9 MW. The decrease in estimated potential capacity compared to the *WSHPDR 2019* comes after a re-evaluation of the hydropower system of Puerto Rico by the engineering firm Black & Veatch through a study commissioned by PREPA.[14]

Figure 2. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Puerto Rico (MW)**



Source: Black & Veatch,[14] *WSHPDR 2013*,[15] *WSHPDR 2016*,[16] *WSHPDR 2019*[17]

Table 2. **List of Operational Small Hydropower Plants in Puerto Rico**

Plant name	*Installed capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Toro Negro 1	8.64	Run-of-river	PREPA	1927
Yauco 2	8.00	Run-of-river	PREPA	1953
Garzas 1	7.20	Run-of-river	PREPA	1941

Source: Black & Veatch[14]

The United States Geological Survey (USGS) data have been analyzed to obtain the average discharge of the main rivers in Puerto Rico (44 in total).[18] Since all of the potential natural sites for larger reservoirs have already been used, the main potential growth area for SHP is micro-hydropower (units not exceeding 100 kW in capacity). The potential for micro-hydropower generation was determined using water flow and net head.[18] A net head range from 3 metres to 120 metres was considered due to variations from river to river or from location to location in the same river. The total micro-hydropower potential is approximately 3.1 MW (Table 3). This was the first attempt to estimate the micro-hydropower potential in Puerto Rico.[18] Not all potential sites were included in the estimate since many potential sites are not monitored.

Table 3. **Estimated Micro-Hydropower Potential in Puerto Rico**

Hydrologic unit	*Available potential (kW)*
Eastern Puerto Rico	1,148
Cibuco-Guajataca	1,067
Southern Puerto Rico	766
Culebrinas-Guanajibo	101
Total	**3,082**

Source: Izzary Rivera et al.[18]

SMALL HYDROPOWER PROJECTS AVAILABLE FOR DEVELOPMENT

The Black & Veatch study examined the need for refurbishment of the inactive plants and the improvement and modernization of the active plants. The study determined a need for a capital investment of approximately USD 140.5, million, which would result in a more than seven-fold increase in annual generation for a total potential generation of 112.7 GWh (Table 4) and a net present value (NPV) of USD 242.4 million over the 30-year period considered in the study (Table 5).[14]

Table 4. **List of Selected Small Hydropower Projects Available for Investment in Puerto Rico**

Plant name	*Installed capacity (MW)*	*Average annual generation without recommended improvements (MWh)*	*Potential capacity with recommended improvements (MW)*	*Average annual generation with recommended improvements (MWh)*	*Type of site (new/refurbishment)*
Caonillas 2	3.60	–	1.00	5,200	Refurbishment
Toro Negro 1	8.64	5,123	8.64	26,700	Refurbishment
Toro Negro 2	1.92	85	1.92	3,300	Refurbishment
Garzas 1	7.20	2,829	7.20	12,500	Refurbishment
Garzas 2	5.04	–	5.04	8,800	Refurbishment
Yauco 2	8.00	7,523	9.00	27,300	Refurbishment
Río Blanco	5.00	–	5.00	28,890	Refurbishment
Total	**40.40**	**15,560**	**37.80**	**112,690**	

Source: Black & Veatch[14]

Table 5. **Summary of Capital Costs and Net Present Value for Small Hydropower Refurbishment Projects in Puert Rico**

Plant name	*Recommended Improvements*	*Total capital cost (USD)*	*Net present value (USD)*
Caonillas 2	New 1 MW full auto with bypass and sediment passage gates	20,300,000	(9,843,000)
Toro Negro 1	Rehabilitate small diversions with full automation, new penstocks	42,133,000	31,241,000
Toro Negro 2	Full automation and new penstocks	22,077,000	(2,510,000)
Garzas 1	Tyrolean weirs on small diversions, full automation and new penstocks	26,347,000	23,638,000
Garzas 2	Tyrolean weirs on small diversions, full automation and new penstocks	25,246,000	19,615,000
Yauco 2	Modify Yahuecas and Prieto to pass sediment, reliability improvements and full automation	3,176,000	92,008,000
Río Blanco	Restore all small diversions to service and full automation	1,200,000	88,214,000
Total		**140,479,000**	**242,363,000**

Source: Black & Veatch[14]

RENEWABLE ENERGY POLICY

Since 2010, in Puerto Rico local and foreign renewable energy businesses could choose between two incentive schemes: the Economic Incentives for the Development of Puerto Rico of 2008 and the Green Energy Fund (GEF) created by Act 83 of 2010.[19] The United States Energy Information Administration (EIA) provides some tax credits and incentives. Tax incentives include a 4 per cent fixed income rate for 15 years and a 90 per cent exemption from property taxes for 15 years. Tax credits can be up to 50 per cent to cover the expenses related to qualified research and development or to cover the cost of machinery and equipment for the generation and efficient use of energy for companies that produce their own power. Companies producing energy for domestic consumption can benefit from the GEF programme.

The GEF, worth USD 290 million and spanning over a 10-year period, supports three tiers of renewable energy projects.[20] Tier I, II and III targets correspond to residential and small businesses below 100 kW, mid-scale businesses between 100 kW and 1 MW and large-scale businesses over 1 MW, respectively.[20]

The Puerto Rico Sales and Use Tax Exemption for Solar Equipment, introduced in 2008, is a sales tax incentive that exempts taxes on solar power equipment and associated accessories and components.[21] Since 2019, the Energy Support Programme was introduced as a grant that aims to provide small and medium enterprises with USD 25,000 for the installation of renewable energy systems.[20]

Act 83 of 2010 introduced Renewable Energy Certificates (RECs). These are assets equivalent to 1 MWh generated from a green energy source. Starting in 2013, RECs could be bought, sold or transferred between entities. This enabled Puerto Rico to participate in the United States (US) renewable energy market. The RECs are also marketable abroad.[19]

The Renewable Portfolio Standard, created by Act 82 of 2010, set ambitious renewable energy production targets of 12 per cent by 2015, 15 per cent by 2020 and 20 per cent by 2035.[22] However PREPA failed to meet those targets with a total renewable energy generation reaching 3 per cent in 2020.[16] PREPA set new targets to derive 40 per cent of its electricity from renewable sources by 2025, 60 per cent by 2040 and 100 per cent by 2050.[11]

Act 57 of 2014, known as the Transformation and Energy Relief Act, created the Puerto Rico Energy Commission (PREC), an independent regulatory body overseeing PREPA's activities.[23] The commission is responsible for approving rate increases and urged PREPA to prepare a new Integrated Resource Plan aiming to optimize transparency and energy efficiency for electricity coming from fossil fuels and enable more renewable energy use at the distribution level. Under the updated Integrated Resource Plan, PREPA approved the refurbishment and modernization of the island's SHP plants.[12]

After Hurricane Maria struck Puerto Rico in September 2017, and the island's subsequent struggles to re-establish power over the territory, on 4 January 4 2018, the PREC released proposals emphasizing the role of renewable energy by establishing micro-grid installations.[17] The proposal defines that micro-grids must qualify as either renewable (at least 75 per cent of power from clean energy), combined heat-and-power or hybrid, and "shall consist, at a minimum, of generation assets, loads and distribution infrastructure". These are, by definition, owned by entities other than PREPA, but small cooperatives can interconnect with PREPA's grid by incurring a monthly fee of USD 25–250.[24] As part of the effort towards the development of micro-grids in Puerto Rico, the Rocky Mountain Institute (RMI) is collaborating with Fundación Comunitaria de Puerto Rico and Resilient Power Puerto Rico to assess the opportunity for resilient micro-grids on the island. This joint project is funded by the Rockefeller Foundation.[25]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

In Puerto Rico, SHP plants are regulated by some of the same legislation as larger hydropower projects. The main legislation and regulation documents concerning hydropower are:

- Puerto Rico Energy Public Policy Act (2019);
- Puerto Rico Electric Power Authority Act (1941);
- Puerto Rico Green Energy Incentive Law (2010).
- Legislation addressing SHP include:
- Hydropower Regulatory Efficiency Act (2013);
- Public Utility Regulatory Policies Act (1978);
- Federal Power Act (1920).

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Many energy projects, including SHP, are funded by PREPA, which in turn receives funding from the Government of Puerto Rico and also, by extension, the US Government.[11] In addition to PREPA, the GEF provides funding for SHP projects in the form of rebates. For tier I projects (0–100 kW), rebates of up to 40 per cent of eligible costs are offered by the GEF on a first-come, first-served basis. For tier II projects (101 kW–1 MW), up to 50 per cent rebates are offered by the GEF through a quarterly competitive process.[19]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Due to increasingly frequent extreme climatic and seismic events such as the hurricane seasons of 2017 and 2019 and the series of earthquakes in 2020, electricity infrastructure in Puerto Rico has been considerably damaged. Many transmission lines were damaged, leaving a third of the population without electricity. These types of events resulting from climate change have already affected SHP in the past, with floods from Hurricane Georges damaging the Caonillas 2 plant in 1998. This plant was still awaiting refurbishment in 2021.

As most electrical infrastructure in Puerto Rico is situated in easily flooded areas, SHP plants are also threatened by the rising sea level, which could flood the island's coast. Finally, SHP plants in Puerto Rico are also affected by the limited water resources, which could worsen as irregular rainfall patterns have already been observed.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In the short term, an increase in SHP generation could come from improvements in PREPA's existing hydropower units and also through micro-hydropower connected through net metering or in a stand-alone mode.[14]

There are, however, many barriers to SHP. The main ones include:

- A lack of finance: between PREPA and its bankruptcy, securing finance for any type of power plant will be difficult. Investment might also be difficult due to years of PREPA mismanagement;
- Limited SHP potential, compared with other renewable energy resources, in particular, solar, wind and

tidal power;
- Risk of severe weather events that could damage hydropower equipment;
- Lack of reservoir management. However, it is possible that if existing reservoirs were properly maintained, namely being dredged periodically, as well as if new generators were put in place and better water management were implemented, the potential for SHP could increase threefold;
- Limited water resources, which are used in the country mainly for human consumption;
- Some obstacles associated with micro-hydropower include little experience with this option in Puerto Rico and the division of regulatory oversight among local and federal (US) agencies, which does not present a clear permitting process for hydropower alternatives.[11,14]

Enablers for SHP development in Puerto Rico include:
- Government support for renewable energy in the form of subsidies for energy transition to renewable systems;
- Laws and regulations that support the development of SHP;
- PREPA's interest to refurbish and modernize SHP plants, including the commissioning of a study on the feasibility of refurbishment in 2021. This study produced a detailed report outlining the costs of improvement and the NPV in the long term;
- In 2021, the US Government rejoined the Paris Agreement, which implies a recommitment to investing in the fight against climate change and renewable energy, including hydropower and, by extension, SHP. With Puerto Rico being an unincorporated US territory, it stands to benefit from this recommitment to sustainable solutions.

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Saint Lucia

Laura Stamm, International Center on Small Hydropower (ICSHP)

KEY FACTS

Population	183,629 (2020)[1]
Area	616 km^2[2]
Topography	An island of volcanic origin, Saint Lucia has a very rugged terrain. Jagged mountains of forested peaks and deep valleys, largely cover the interior of the country. In the south, the mountains tend to have even steeper slopes than in the north. The highest peak is Mount Gimie at 959 metres above sea level located towards the south-central region.[2]
Climate	Saint Lucia has a tropical maritime climate with little variation throughout the year. Temperatures typically range from 23 °C to 31 °C with an overall average of 27 °C at sea level. In higher elevations temperatures can dip to as low as 13 °C. While humidity remains above 70 per cent all year long, seasons are categorized by precipitation with a wet season between June and November and a drier season between December and May.[2]
Climate Change	Maximum temperatures in Saint Lucia have increased by over 1 °C since 1975 and the number of extremely hot days in a given year has also increased. This trend is expected to continue in the upcoming decades. Prevalence of hurricanes and overall windspeeds have increased but overall average rainfall per year has decreased within the past decades. As climate change continues into the future, natural disasters are expected to become more intense and the general climate is expected to become hotter and drier.[3]
Rain Pattern	Rainfall varies between seasons and elevation. Average rainfall is approximately 1,450 mm per year on the coasts near sea level and approximately 3,420 mm per year at higher altitudes in the interior. During the wet season from June to November, rain falls at a country-wide average rate of 200–250 mm per month, and between December and May usually less than 150 mm will fall per month. Occasional hurricanes are experienced during the wet season.[3,4]
Hydrology	There are 37 watersheds in Saint Lucia, of which 7 are of significance. These are the Roseau, Marquis, Cul-de-Sac, Fond D'Or, Troumassee, Cannelles and Vieux Fort Rivers. These rivers begin in the central region of high elevation and flow downwards to empty into the sea. The watersheds in the north of the island tend to be larger than those of the south, with the Roseau watershed being the largest.[4]

ELECTRICITY SECTOR OVERVIEW

At the end of 2020, total installed capacity in Saint Lucia was 91.6 MW with an available capacity of 88.4 MW that satisfied a peak demand of 59 MW. Most of the installed capacity, or 87.4 MW (over 95 per cent), was from the diesel-fuelled Cul-de-Sac power plant. A solar farm in La Tourney with an installed capacity of 3 MW and 1.23 MW of distributed solar photovoltaics (PV) rooftop panels feeding into the grid (under 5 per cent of the total) are the sources of renewable energy in the country (Figure 1).[5]

Figure 1. **Installed Electricity Capacity by Source in Saint Lucia in 2020 (MW)**

Source: LUCELEC[5]

Total electricity generation in Saint Lucia for the year 2020 amounted to 367.5 GWh, of which approximately 360.9 (98 per cent) was from diesel fuel and 6.6 GWh (2 per cent) was from solar power (Figure 2). Approximately 336.5 GWh was sold by the country's electricity company during the year. The residential sector consumed a total of 136.5 GWh and the commercial sector (excluding hotels) consumed 120.3 GWh. Hotels, usually one of the most important buyers of electricity in the country's tourism-dependent economy, consumed 51.5 GWh, which was an almost 40 per cent decrease from previous years due to the COVID-19 pandemic. The industrial sector consumed 17.8 GWh and street lighting used 10.3 GWh.[6] The sector experienced just under a 6 per cent loss of electricity for the year.[5]

Figure 2. **Annual Electricity Generation by Source in Saint Lucia in 2020 (GWh)**

Source: Department of Finance[6]

Access to electricity in Saint Lucia was over 99 per cent as of 2019.[7] St. Lucia Electricity Services Limited (LUCELEC) is the only electricity company in the country and is responsible for generation, distribution and transmission. It was created and granted sector exclusivity under the Ordinance No. 27 of 1964. The company was publicly owned until the passing of the Electricity Supply Act of 1994, which privatized its ownership but maintained its exclusivity. Currently, it is partially owned by several private entities with 10 per cent of its shares held by the Government of Saint Lucia.[8] The National Utilities Regulatory Commission (NURC) was created in 2016 as the electricity sector's regulatory body.[9]

Electricity tariffs vary based on consumer type and consumption level. Each group has a specified basic energy rate and then a standardized fuel surcharge is added. The basic rate is adjusted annually and the fuel surcharge is adjusted monthly based on global fuel prices. Table 1 shows the electricity tariffs for each type of customer as of April 2022.[10]

Table 1. **Electricity Tariffs by Consumer in Saint Lucia in April 2022**

Type of consumer	Usage	Basic energy rate (USD/kWh)	Fuel surcharge (USD/ kWh)	Final tariff rate (USD/ kWh)
Domestic	1–180 units	0.27	0.087	0.36
	> 180 units	0.29	0.087	0.38
Commercial	Low tension	0.33	0.087	0.42
	High tension (bulk)	0.31	0.087	0.40
Industrial	Low tension	0.33	0.087	0.42
	High tension (bulk)	0.31	0.087	0.40
Street lighting	All units	0.33	0.087	0.40

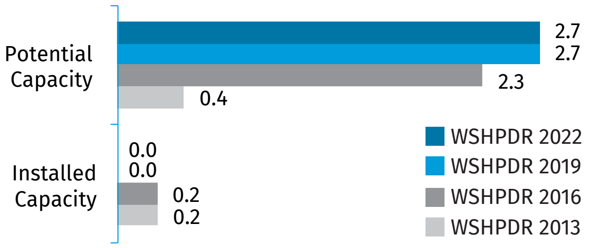
Source: LUCELEC[1]

SMALL HYDROPOWER SECTOR OVERVIEW

As there is no local definition for small hydropower (SHP) in Saint Lucia, in this chapter it is defined as plants with a capacity of up to 10 MW.

While potential capacity is estimated at approximately 2.68 MW, there were no hydropower plants in operation in the country as of 2022. There was an SHP plant in Latille Falls constructed in 2006 with a capacity of 240 kW, however, it has been years since it was severely damaged by a hurricane and is no longer in operation.[11] Most recently, a feasibility study of a potential hydropower site at the John Compton Dam on the Roseau River was carried out by a German consultancy organization in 2015. Although the study confirmed a possibility of an SHP plant of 336 kW and deemed it technically and economically feasible, no official plans to construct it have been announced as of yet.[12] Without new discoveries of potential capacity or construction of new plants in the past few years, the information remains the same since the last publication of the *World Small Hydropower Development Report (WSHPDR)* in 2019 (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Saint Lucia (in MW)**



Sources: *WSHPDR 2019*,[13] *WSHPDR 2016*,[14] *WSHPDR 2013*[15]

There are no local financial mechanisms specifically aimed at supporting SHP projects. However, there may be opportunities to receive support through renewable energy projects being developed by the Government of Saint Lucia.

RENEWABLE ENERGY POLICY

The country's first legislation that mentions renewable energy was the Electricity Supply Act of 1994. LUCELEC was privatized in this act with the aim that outside sources would provide financial funding for renewable energy development and the act provided voluntary financial incentives for it. In 1999, the Government of Saint Lucia announced that exemptions for import and consumption taxes would be given to developers of renewable energy but no institutional or regulatory framework was created to enforce it.[2,16]

Over a decade later, the National Energy Policy of 2010 was established in order to create an enabling regulatory and institutional environment towards increasing the renewable energy share in the energy mix. It set a goal to achieve a 5 per cent share of renewable energy in the mix by 2013, a 15 per cent share by 2015 and a 30 per cent share by 2020. Due to its non-intermittent nature and large potential, the plan favoured the development of geothermal energy to satisfy the base-load demand of electricity, but recognized the importance of all types of renewable energy. It granted grid preference to any type of renewable energy that would be available over fossil fuels, on the condition that the energy stability would not be compromised.[16] As of 2022, the goals that were set in this plan have not been reached.

In 2017, the Government and LUCELEC published the forward-looking National Energy Transition Strategy. This outlined possible scenarios of what the country's energy sector could look like in 2025, ranging from a 0 per cent share of renewable energy to an over 75 per cent share of renewable energy. Each scenario was tested on grounds such as potential future incurred debt, operational costs and external shocks such as high oil prices. Considering the country's economic standing it was found that the optimal strategy would be to install 30 MW of solar power and 12 MW of wind power by 2025. It was also recognized that unless foreign capital is used for geothermal energy development, it is not feasible for domestic investment despite the fact that it would be necessary to achieve the scenario of an over 75 per cent share of renewable energy.

In January 2020, LUCELEC made plans to set groundwork for a smart grid as well as to work towards the installation of a 10 MW solar power system and a 12 MW wind farm. These projects have since been put on hold due to the COVID-19 pandemic.[5]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers to SHP development in Saint Lucia include, but are not limited to:

- The generally low baseflows of the main rivers, which are unable to support hydropower plants;
- Other renewable energy sources, particularly solar power and wind power, are given a higher priority in the Government's policies and development plans, and in public and private sector projects.[13]

The key enablers for SHP development in Saint Lucia are:

- The positive feasibility study of SHP on the Roseau River that has not been taken advantage of;
- Inclusion of hydropower would lessen the country's over 90 per cent reliance on diesel and could help reach the set renewable energy goals.

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Saint Vincent and the Grenadines

Davy Rutajoga, International Center on Small Hydro Power (ICSHP)

KEY FACTS

Population	110,947 (2020)[1]
Area	389 km^2[2]
Topography	The country consists of the main island, Saint Vincent, and a chain of 32 smaller islands, the Grenadines. Saint Vincent is a mountainous, volcanic island, located north of Trinidad and Tobago. It borders the Caribbean Sea in the west and the Atlantic Ocean in the east. The highest point is Soufriere, an active volcano with an altitude of 1,234 metres. Steep slopes and rugged landscapes comprise the remaining territory of Saint Vincent Mount Tobai, on Union Island, is the highest point in the Grenadines, with an altitude of 308 metres. The topography of the Grenadines is characterized by beaches and shallow bays.[3]
Climate	The climate of Saint Vincent and the Grenadines is tropical, characterized by increased humidity and uniform temperatures throughout the year. The average annual temperatures are estimated at 27 °C. September is the hottest month, with temperatures reaching an average of 29 °C. February is considered the coldest and windiest month. Winds in February reach on average 23 km/h and the average temperature is 25 °C.[4]
Climate Change	Saint Vincent and the Grenadines is affected by extreme climatic events associated with climate change, particularly, due to the country's location within the Atlantic hurricane belt. Some of these are intense hurricanes, such as the Hurricanes Ivan and Thomas of 2004 and 2010, respectively. The country is also experiencing warmer days and nights, unpredictable and reduced rainfall, droughts, floods, landslides, coral bleaching with rising ocean temperatures and coastal erosion.[5] The mean annual temperature is predicted to keep increasing at an average rate of 0.15 °C per decade. Rainfall is predicted to decrease, with negative median values of between 15 per cent and 22 per cent annually by the 2090s.[6]
Rain Pattern	The annual precipitation in Saint Vincent and the Grenadines is estimated to be between 1,500 mm and 6,000 mm.[7] Precipitation has seen a decline of approximately 8.2 mm per month per decade since 1960.[8] Rainfall is an important source of freshwater for the Grenadines and this decline is likely to affect water resources in the region.
Hydrology	There are no navigable rivers in Saint Vincent and the Grenadines, most of them being short and straight. The Colonaire is the longest river in the country. Other important rivers are the Buccament, Cumberland and Warrowarrow.[9] River defences were planned to be constructed on the Colonaire, Buccament, Cumberland and Warrowarrow by the Government of Saint Vincent and the Grenadines in collaboration with the Canada Caribbean Resilience Facility (CRF) as part of the Disaster Vulnerability Reduction Project (DVRP).[10]

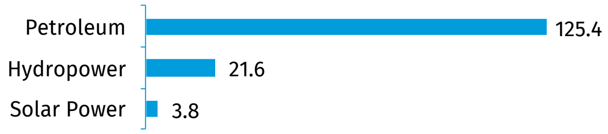
ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in Saint Vincent and the Grenadines are petroleum and hydropower. The country is heavily reliant on imported petroleum, which accounted for approximately 83 per cent of the 150.8 GWh of electricity generated in the country in 2020. Hydropower accounted for less than 15 per cent and solar power accounted for less than 3 per cent of the generated electricity (Figure 1).[11] The installed capacity in the country in 2020 was 54 MW, with over 85 per cent from petroleum, over 11 per cent from hydropower and over 3 per cent from solar power (Figure 2).[11] The electricity in Saint Vincent and the Grenadines' islands of Bequia, Canouan, Mayreau and Union is generated, transmitted and distributed by Saint Vincent Electricity Services Ltd (VINLEC), which owns the monopoly in the region. Electricity on Mustique Island is produced by Mustique Company Ltd. Total access to electricity is estimated at 100 per cent.[11,12]

Figure 1. **Annual Electricity Generation by Source in Saint Vincent and the Grenadines in 2020 (GWh)**

Source: Statistical Office[11]

Figure 2. **Installed Capacity by Source in Saint Vincent and the Grenadines (MW)**



Source: Statistical Office[11]

The electricity in Saint Vincent and the Grenadines is regulated by VINLEC and the Cabinet of the Government of Saint Vincent and the Grenadines. VINLEC uses networks spanning over 563 kilometres to provide electricity to customers. It became a fully state-owned enterprise in 1985 after being incorporated in 1961 and selling an initial 49 per cent of its shares to the Government in 1971.[13]

In order to assist in formulating and implementing policies related to energy as well as coordinating specific activities related to renewable energy and energy efficiency initiatives, the Government of Saint Vincent and the Grenadines created the Energy Unit.[14]

The average electricity tariffs for the four main groups of consumers are listed in Table 1. According to VINLEC, a value-added tax (VAT) of 16 per cent is applicable to domestic customers who consume more than 150 kWh. This tax is also paid by all commercial and industrial customers.[15]

Table 1. **Average Electricity Tariffs in Saint Vincent and the Grenadines**

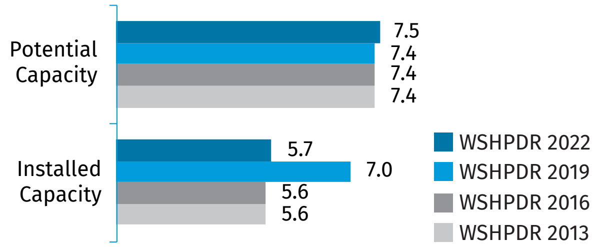
Type of consumer	*Average electricity tariff (USD/kWh)*
Residential	0.19
Commercial	0.20
Industrial	0.16
Street lighting	0.21

Source: ETI[16]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition used by the country for small hydropower (SHP) is up to 10 MW. The installed capacity of SHP in Saint Vincent and the Grenadines is estimated at 5.7 MW and comes from three plants: the South Rivers, Richmond and Cumberland hydropower plants.[12] However, their capacity is not available at full scale year-round, with the available capacity decreasing to approximately 2 MW during the dry season, which creates the need to use diesel plants for back-up.[17] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the SHP installed capacity decreased based on more accurate data (Figure 3). The total SHP potential is estimated to be 7.5 MW.[12]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Saint Vincent and the Grenadines (MW)**



Source: CCREEE,[12] *WSHPDR 2013*,[18] *WSHPDR 2016*,[19] *WSHPDR 2019*[20]

Table 2. **List of Operational Small Hydropower Plants in Saint Vincent and the Grenadines**

Name	*Installed capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Cumberland	3.65	Run-of-river	VINLEC	1987
Richmond	1.10	Run-of-river	VINLEC	1962
South Rivers	0.96	Run-of-river	VINLEC	1952

Source: VINLEC[21]

A study for the rehabilitation of the Richmond plant and the expansion of South Rivers plant was conducted in 2009. Due to favourable findings, VINLEC was prompted to undertake modernization and refurbishment projects at both plants. The first such initiative commenced in 2013 and the refurbishment works at the Richmond and South Rivers plants were completed in 2016 and 2018, respectively.[21] VINLEC also considered developing another power plant of 1.2 MW downstream South Rivers, on the Colonarie, but no updates on progress are currently available.

RENEWABLE ENERGY POLICY

The cost of energy in Saint Vincent and the Grenadines is relatively high. However, there is significant potential for the adoption and implementation of renewable energy. In order to address sustainability issues, the Government established the National Energy Plan (NEP) in 2009. In 2010, an additional document, the National Energy Action Plan (NEAP), provided more accurate details with regards to the initiatives both the public and the private sector will undertake to promote the dissemination of renewable energy projects in the country.[22]

While the National Energy Action Plan (NEAP) specified a diverse variety of measures for implementation and even designed short- and long-term targets, it has not been successful in achieving the set target of 60 per cent of electricity output produced through renewable energy by 2020.[11]

Although the country's potential is high, more financial and construction policies to motivate and accommodate investors are needed.

In addition to these policies, the country has also implemented feed-in tariffs (FITs), tax reductions and exemptions for the usage of renewable energy and green public procurement.

VINLEC has also undertaken multiple studies to evaluate the feasibility of investing in renewable energy. Some of the projects that the company is considering or recently completed in collaboration with the Government of Saint Vincent and the Grenadines are outlined below:

- Ribishi Point was identified as a suitable site for the development of wind power after a 2005 study conducted by VINLEC, however, the project stalled due to the proximity to the new airport and scaling down of the project is currently being explored; other locations, including some of the small Grenadines islands, are also being considered;
- The installation of solar panels on a car park canopy and the roofs of the transformers and back-up generator sheds at the Cane Hall Engineering Complex for a total capacity of 30 kW;
- A 370 kW solar PV plant installation project was commissioned at the Lowmans Bay Power Station in 2014 and is operational;
- A joint project with Emera Caribbean Inc. and Reykjavik Geothermal to develop the geothermal potential of the island; however, the project has been challenged by the lack of sufficient permeability of the resource tapped by the wells drilled;
- Generating electricity through the recovery of heat from waste is another measure that the Government of Saint Vincent is considering.[12,17,23,24,25]

The Regional Disaster Vulnerability Reduction Project is a USD 23 million project conceived in 2011 and aiming, among other things, to strengthen river embankments in Saint Vincent and the Grenadines. As part of this project, coastal areas and infrastructure are to be protected from climate change-related damage, thus ensuring the safety of hydropower plants. The final phase of the implementation of this project, set for December 2020, was hindered by the travel restrictions imposed to curb the spread of COVID-19.[26]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP plants are regulated by some of the same legislation as larger hydropower plants. The main legislation and regulation documents in Saint Vincent and the Grenadines concerning hydropower are:

- The Electricity Supply Act (1973);
- Hydroelectric Ordinance No. 24 (1951).

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are numerous barriers to SHP development Saint Vincent and the Grenadines, including:

- No specific plan on SHP development has been defined;
- Despite the attempts to encourage investment in renewable energy, the market is still heavily reliant on fossil fuels for electricity production;
- VINLEC's monopoly may prevent smaller private companies from effectively developing and implementing renewable energy projects at profitable rates;
- Limited potential for SHP development, particularly on the smaller islands;
- Seasonal rainfall variability affects SHP as hydropower availability can decrease by 50 per cent or more during the dry season;
- SHP is no longer a priority for the Government, with most investment being focused on the development of solar and geothermal power.[27]

The factors that favour further SHP development in the country include:

- The Government has been actively promoting renewable energy solutions and has implemented initiatives to raise awareness of the efforts made by the country to embrace renewable energy and the potential for further investment;
- The Government has been increasingly promoting small-scale sustainable energy projects as well as the introduction of electric vehicles;
- Availability of incentives in the form of FITs, tax reductions and exemptions for the usage of renewable energy;
- Availability of financial and capacity building support from international institutions, such as the Global Environment Facility (GEF), World Bank, International Renewable Energy Association (IRENA), etc.[12,28,29]

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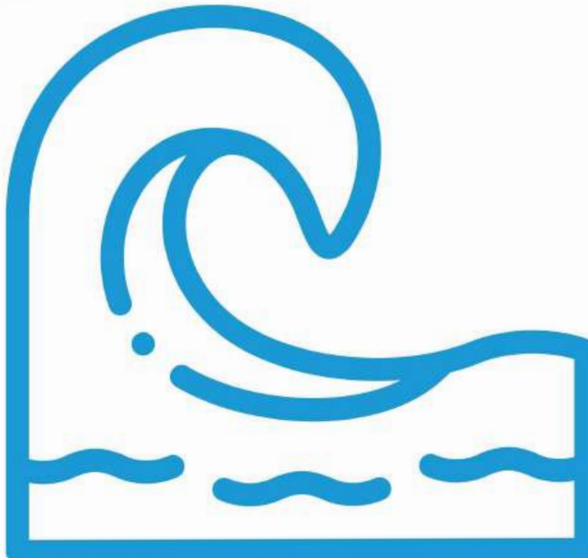


2.2. Central America

Countries: Belize, Costa Rica, El Salvador, Guatemala, Honduras, Mexico, Nicaragua, Panama

INTRODUCTION TO THE REGION

The electricity sectors of countries in Central America are marked by a relatively high degree of diversification, high electricity access and significant involvement of private companies. Fossil fuels are the leading source of electricity generation in Guatemala, Mexico and Nicaragua. In other countries in the region fossil fuels generally play a supporting role, with thermal power capacities held in reserve to supplement variable generation from renewable energy sources (RES). For example, in Belize, thermal power from fossil fuels accounted for just 9 per cent of annual generation in 2020. Nearly all major RES are well-established in the region, including hydropower, solar power, wind power and bioenergy. This also includes geothermal power, which is widely used across Central America and plays a particularly important role in the electricity mix of El Salvador and Nicaragua.

Central America is well-supplied with hydropower resources, and hydropower is the leading RES in the region by installed capacity. Mexico accounts for the largest share of regional hydropower capacity, while Belize and Costa Rica have the highest proportion of their installed capacity provided by hydropower. Although nearly all countries in the region rely on hydropower to a significant extent, the interannual and seasonal variability in generation from hydropower in the region requires the maintenance of significant reserve capacities provided by other energy sources.

Private companies play a major role in the production of electricity in the region. During the 1990s, most countries in the region underwent a period of liberalization and privatization in the energy sector, with state-owned energy companies including electricity producers, providers and companies in the oil and gas sector undergoing unbundling and partial or full privatization. The process of electricity sector privatization has continued through the first two decades of the 21st century but has generated increasing opposition, particularly in Mexico. Among the countries in the region, the electricity sectors of Honduras and Guatemala are the most fully privatized, with private companies operating 80 per cent and 86 per cent of these two countries' respective electricity capacities. In other countries, the share of installed capacity operated by private companies is in the 20–50 per cent range.

The degree of interconnectivity in the region is very high, with El Salvador, Costa Rica, Guatemala, Honduras Nicaragua and Panama all connected to the Central American Electric Interconnection System (SIEPAC). The Mexico-Belize interconnection is likewise important and provides Belize with roughly a third of its electricity supply. Mexico has additional interconnections with Guatemala as well as with the United States of America on its northern border, while Panama shares interconnections with its southern neighbour Columbia.

An overview of the electricity sectors of the countries in the region is provided in Table 1.

Table 1. **Overview of Central America**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Belize	0.4	93	88	132	433	55	242
Costa Rica	5	99	N/A	3,566	11,313	2,343	7,827
El Salvador	7	98	95	2,360	5,388	574	1,985
Guatemala	17	92	N/A	3,993	12,224	1,560	4,381
Honduras	10	85	71	2,830	10,888	849	3,765
Mexico	126	100	100	87,894	317,820	12,614	23,602
Nicaragua	7	88	74	1,620	3,797	157	575
Panama	4	96	88	4,128	10,887	1,810	7,226
Total	-	-	-	**106,523**	-	**19,961**	-

Source: WSHPDR 2022[1]

Note: Data in the table are based on data contained in individual country chapters of the WSHPDR 2022; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

There is no universally-accepted definition of small hydropower (SHP) in Central America. Honduras defines SHP as hydropower plants with an installed capacity of up to 30 MW. El Salvador and Guatemala adhere to the up to 5 MW definition, in line with the definition proposed by the Latin American Energy Organization (OLADE), while Nicaragua uses the up to 10 MW definition. No official definition of SHP exists in Belize, Costa Rica, Mexico or Panama, although Panama provides incentives for hydropower plants of up to 20 MW without classifying such plants as SHP, and Mexico uses the up to 30 MW definition for the purpose of incentivization.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Central America (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Belize	N/A	N/A	N/A	10.3	21.7
Costa Rica	N/A	N/A	N/A	126.5	126.5*
El Salvador	Up to 5 MW	21.7	N/A	21.7	119.6
Guatemala	Up to 5 MW	123.0	204.9	123.0**	204.9**
Honduras	Up to 30 MW	288.6	N/A	148.0	385.0
Mexico	N/A	699.3***	N/A	N/A	N/A
Nicaragua	Up to 10 MW	26.6	104.7	26.6	104.7
Panama	N/A	N/A	N/A	147.2	263.5
Total	-	-	-	**603.3**	**1,225.9**

Source: WSHPDR 2022[1]

Note: *Based on installed capacity. **Based on the local definition of SHP. ***Based on the up to 30 MW definition of SHP.

The total installed capacity of SHP up to 10 MW in Central America is 603.3 MW, while estimated potential capacity is 1,225.9 MW. Relative to the World Small Hydropower Development Report (WSHPDR) 2019, the installed capacity has increased 15 per cent due to ongoing SHP development in several countries in the region, including Guatemala, Honduras, Nicaragua and

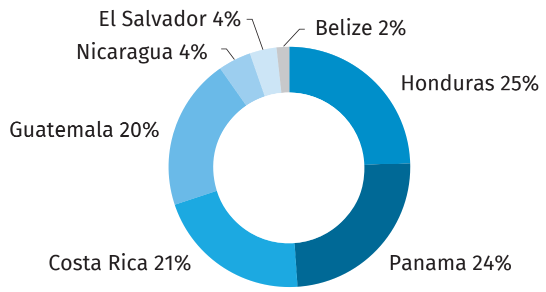
Panama. Meanwhile, the estimate of potential capacity has increased by approximately 2 per cent, mainly as a result of more recent data on the estimated potential SHP capacity of Nicaragua.

Mexico is the regional leader in SHP capacity based on the SHP definition of up to 30 MW, but even under this definition SHP accounts for only a small share of the country's total hydropower capacity. By contrast, SHP accounts for 17 per cent of all hydropower capacity in Nicaragua, 17 per cent in Honduras and nearly 19 per cent in Belize. Guatemala, Honduras, Nicaragua and Panama have all seen significant increases in total installed SHP capacity in recent years. Factors that have contributed to SHP development in these countries include state-supported incentive schemes as well as funding provided by international development programmes. In Belize, Costa Rica, El Salvador and Mexico, little recent SHP development has taken place.

Challenges faced by the SHP sector in the region require a comprehensive response. In particular, climate change is emerging as a major barrier to SHP development, and needs to be addressed through appropriate planning and adaptation measures, particularly in the case of prolonged drought. Climate change response in the region requires a more effective model of public-private-community collaboration, including the introduction of integrated watershed management that would provide a platform for local communities to fully participate in the decision-making and profit-sharing aspects of SHP construction and operation.

The national share of regional installed SHP capacity by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

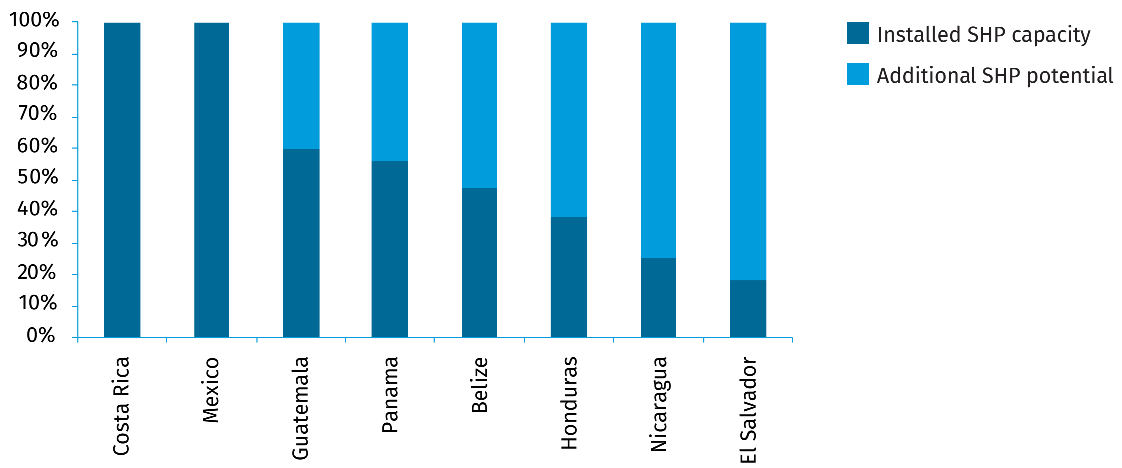
Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Central America (%)**



Source: WSHPDR 2022[1]

Note: Mexico not included due to lack of data on SHP up to 10 MW.

Figure 2. **Utilized Small Hydropower Potential by Country in Central America (%)**



Source: WSHPDR 2022[1]

Note: For SHP up to 10 MW except in the case of Mexico, where the up to 30 MW definition is used, and Guatemala, where the local definition is used. For Costa Rica and Mexico, all SHP potential is assumed to be utilized due to a lack of reliable estimates of potential capacity.

The installed capacity of SHP up to 10 MW in **Belize** is 10.3 MW, provided by two SHP plants, and has not changed since the commissioning of the second plant in 2005. The potential capacity is estimated at 21.7 MW, indicating that approximately 47 per cent has been developed. The most recent study of SHP potential was carried out in 2006. Since then, no additional activity related to the SHP sector has taken place.

In **Costa Rica**, the installed capacity of SHP up to 10 MW is 126.5 MW, while the estimate of potential capacity is 7,373.5 MW, indicating that approximately 2 per cent has been developed. No new SHP construction has taken place in the country in recent years, although the assessed installed capacity has been revised upwards due to access to better data on existing SHP plants. The estimate of potential SHP capacity in the country is provided on the basis of a 2017 study assessing worldwide hydropower potential.

In **El Salvador**, there are 17 operational SHP plants with a total installed capacity of 21.7 MW, in addition to two plants with a capacity of 0.63 MW that are likely decommissioned or in need of extensive repairs. All existing SHP plants in the country have an installed capacity under 5 MW, and there are no plants in the 5–10 MW capacity range. The potential capacity for SHP up to 10 MW has been estimated at 119.6 MW, of which 18 per cent has been developed. There are two ongoing SHP projects on the San Simon River.

There are 65 operational SHP plants of up to 5 MW in **Guatemala** with a total installed capacity of 123 MW. An additional 33 plants with a total capacity of 80 MW are registered with the Government but are not operational, and one SHP plant with a capacity of 1.9 MW is pending registration. On the basis of these capacities, total potential SHP capacity of up to 5 MW in Guatemala is estimated at 204.9 MW, of which 60 per cent has reached operational status. The undeveloped SHP potential of the country is likely to be higher but no reliable estimate is available.

In **Honduras**, the installed capacity of SHP of up to 30 MW is 288.6 MW provided by 45 plants, of which 37 are plants of up to 10 MW and with a combined capacity of 148 MW. Potential capacity for SHP up to 10 MW is estimated at 385 MW, indicating that 38 per cent has been developed. The installed SHP capacity of the country has been growing steadily over the last decade due to the construction of new plants, but no data on ongoing SHP projects are available.

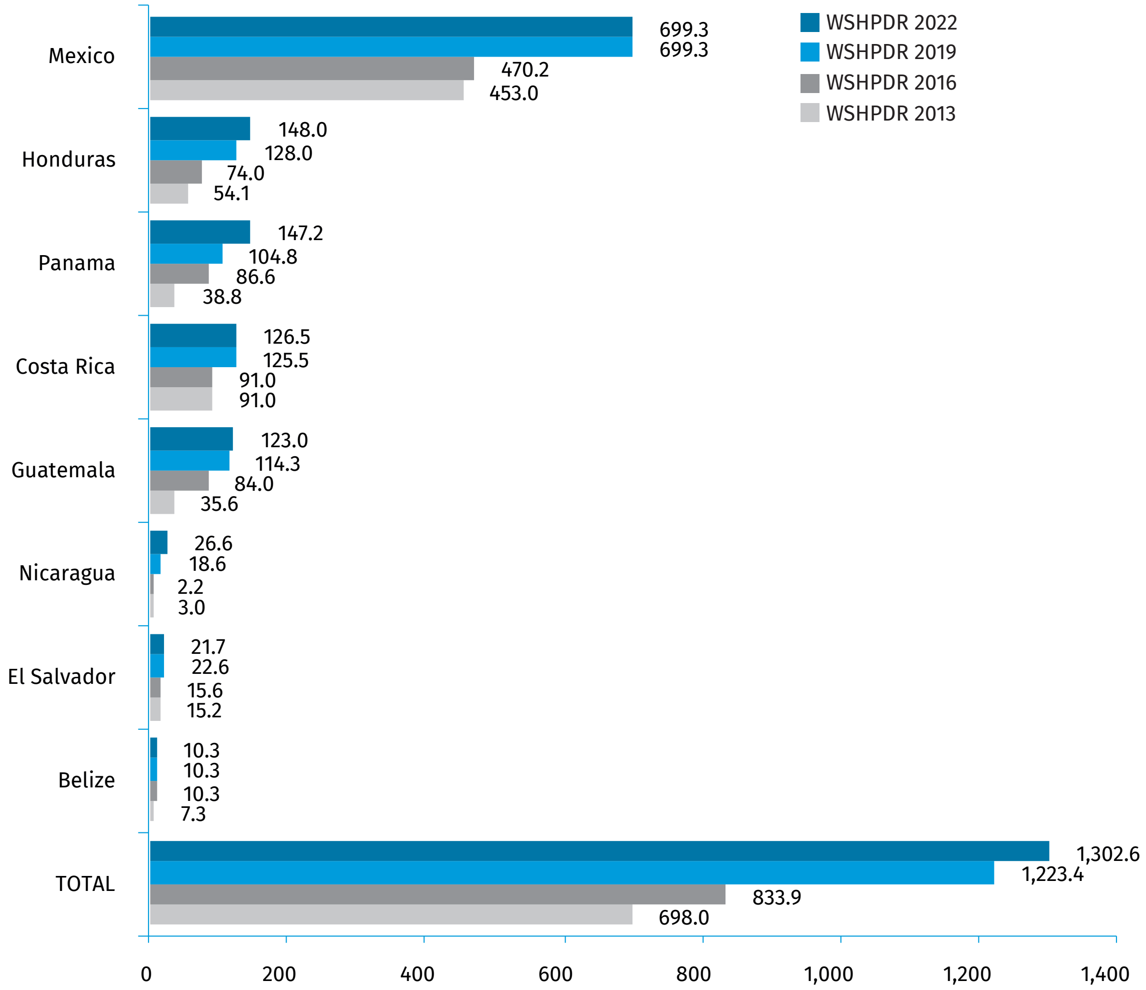
The installed capacity of SHP up to 30 MW in **Mexico** is 699.3 MW, provided by 69 plants. There is no reliable estimate of potential SHP capacity in the country. A large number of studies of SHP potential have been carried out over the last few decades in different parts of the country, producing estimates that differed by a wide margin. At the high end, one study suggested the existence of over 3,000 potential micro-, mini- and small hydropower sites across the country. In addition to existing SHP plants, 41 SHP plants were under construction across the country as of 2021, with a combined planned capacity of 452.5 MW.

There are 17 operational SHP plants of up to 10 MW in **Nicaragua** with a total installed capacity of 26.6 MW. Based on an inventory of 20 potential SHP sites, potential capacity for SHP of up to 10 MW is estimated at 104.7 MW, indicating that 25 per cent has been developed. Three new SHP plants have been constructed in the country in recent years and several additional potential sites have been identified.

The installed capacity of SHP of up to 10 MW in **Panama** is 147.2 MW provided by 24 operational SHP plants, while potential capacity is estimated at 263.5 MW, indicating that 56 per cent has been developed. The installed SHP capacity of the country has expanded considerably over the last few years. There were 9 additional plants under construction as of 2021 and 13 other potential SHP sites have been identified.

Changes in the installed SHP capacities of the countries in the region compared to the previous editions of the WSHPDR are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in Central America (MW)**



Source: WSHPDR 2022,[1] WSHPDR 2013,[2] WSHPDR 2016,[3] WSHPDR 2019[4]

Note: For SHP up to 10 MW except in the case of Mexico, where the up to 30 MW definition is used, and Guatemala, where the local definition is used.

Climate Change and Small Hydropower

The region experiences increased winter precipitation and decreased summer precipitation during the El Niño Southern Oscillation (ENSO) phase. These seasonal differences are expected to become even more pronounced as a result of climate change. The increase in frequency and intensity of extreme events on exposes SHP infrastructure to damage as well as decreases SHP plant load factors due to persistent drought.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In **Belize**, there are no outstanding plans for any further expansions to existing SHP capacity and no incentives or funding are provided for SHP development. This lack of interest is partially informed by the increasing volatility of hydropower generation as a result of rainfall variability induced by climate change, as well as by observed negative impacts of hydropower on the environment. However, given the positive impact of international funding on the development of other RES in the country, similar support could be attracted to develop the country's remaining SHP potential.

Barriers to the development of SHP in **Costa Rica** include environmental restrictions, seasonality of river flow, competitive advantages of solar power and wind power projects, and low electricity demand. The key enabling factor for future development is the country's massive estimated SHP potential. Additionally, Costa Rica possesses considerable technical capacity in the SHP sector and a well-established framework for the development of RES projects.

SHP development in **El Salvador** is hampered by outdated hydrological data and assessments of SHP potential, as well as insufficient financing, competition from other RES due to relatively high development costs, uncertainties in the licensing process and social opposition. At the same time, the estimated SHP potential of the country is considerable and well-documented, although more up-to-date studies are needed.

In **Guatemala**, SHP development has faced opposition for social and environmental reasons, forcing the Government to develop a special consultation framework to address these concerns. Even when SHP development is not opposed by local communities, there are often problems with acquiring funding for SHP projects, particularly in light of the costs of construction and transmission in remote areas. On the other hand, SHP development in the country is facilitated by supportive government policy and by an established system for licensing and regulating SHP projects.

Barriers to SHP development in **Honduras** include issues with road access and transmission of electricity, as well as greater interest on the part of private investors in large power plants. Enablers include the highly liberalized electricity market that simplifies entry for new companies, high demand for electricity access in the countryside and abundant undeveloped SHP potential.

SHP development in **Mexico** faces a wide range of regulatory, financial, technical and political obstacles, including a lack of feed-in tariffs (FITs), rising cost of transmission, a difficult licensing process and a negative public perception of SHP. Lack of accurate nationwide data on SHP potential is another major barrier to development, although detailed partial inventories of potential sites have been developed. Despite a lack of rigorous data, the country's SHP potential is believed to be very considerable and could be more fully realized with the aid of existing incentives such as tax breaks. Additionally, the SHP sector in Mexico is well-positioned to take advantage of rising electricity demand and attractive regional electricity export prices. Finally, Mexico is a major hydropower producer and SHP developers can lean on considerable local technical expertise and construction capacities.

The main barriers to SHP development in **Nicaragua** are financial in nature and include the high upfront cost of projects, the short duration of power purchase agreements, which discourages investors, as well as subsidies for thermal power plants, which put SHP at a competitive disadvantage. Additionally, there is insufficient local technical capacity in the SHP sector. However, the country has few restrictions on foreign direct investment in the energy sector and government policy is strongly supportive of RES development, providing a range of fiscal incentives. The need to extend electricity access to certain rural areas is an additional enabler of SHP development in Nicaragua.

The most important barrier to SHP development in **Panama** is the lack of interest from private finance, meaning that SHP projects, particularly those initiated in rural communities, are dependent on state financing. At the same time, the established legal framework and system of incentives are highly supportive of SHP development, and the country has considerable experience in hydropower as well as significant untapped SHP potential. Furthermore, several ongoing SHP projects in the country have stalled and may be looking to solicit additional investments.

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Belize

Areli Sutherland and Geon Hanson, Energy Unit of Belize

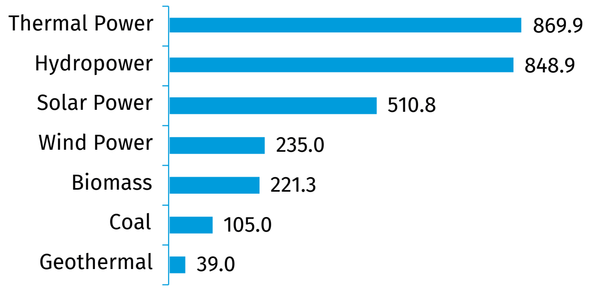
KEY FACTS

Population	397,621 (2020)[1]
Area	22,965 km^2 [2]
Topography	The topography of Belize consists of lowlands and swamps along its northern coast and the Maya Mountains in the southern part of the country. The highest point in Belize is Doyle's Delight at 1,124 metres above sea level.[2]
Climate	The climate of Belize is classified as subtropical. It is characterized by a dry season lasting from late February to May and a wet season lasting from June to November. Average temperatures in Belize City range from 23 °C in December to 29 °C in July.[2]
Climate Change	Belize is considered one of the countries at greatest risk from climate change, ranking third among small countries in susceptibility to natural disasters and fifth in climate change risk. This vulnerability is most significant with regard to hurricane damage from wind, storm surges and other flooding due to the country's coastal position and low elevation of large parts of the country. Projected changes in climate include an increase in temperatures of 2–4 °C by 2100, a 6–8 per cent increase in the length of the dry season with a corresponding shortening of the rainy season and a 20 per cent increase in the intensity of heavy rainfall events.[3,4]
Rain Pattern	The rainy season lasts from June to November, and the dry season is from February to May. Average precipitation depends on the region. In the south, annual rainfall can reach over 4,000 mm, while in the north it can be less than 1,800 mm.[2]
Hydrology	Belize has 18 major rivers in addition to many smaller perennial streams. The Belize River is the largest, running from the Maya Mountains and its tributaries in Guatemala to the Caribbean Sea for a total length of 290 kilometres and draining approximately a quarter of the country's area. Other major rivers include the Sibun River in the south and the New River in the north.[5]

ELECTRICITY SECTOR OVERVIEW

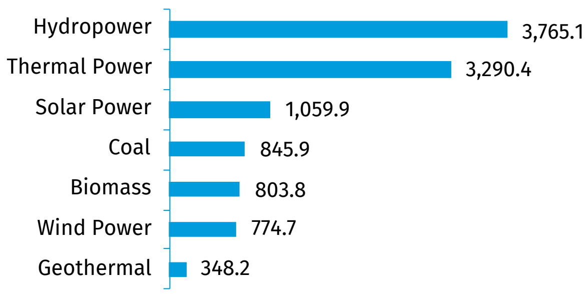
The total installed capacity of existing power plants in Belize was approximately 131.7 MW in 2020. Thermal power from fossil fuels providing 55.3 MW (42 per cent) of the total, hydropower provided 54.5 MW (41 per cent), biomass provided 21.5 MW (16 per cent) and utility-scale solar power provided an estimated 0.5 MW (less than 1 per cent) (Figure 1). In addition, approximately 3 MW of distributed solar power generation is estimated to exist in the country, but data on specific installations is not available.[6,7,8]

Figure 1. **Installed Electricity Capacity by Source in Belize in 2020 (MW)**



Source: Personn,[6] Energy Unit[7,8]

Figure 2. **Annual Electricity Generation by Source in Belize in 2020 (GWh)**

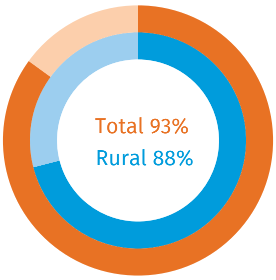


Source: Energy Unit[7,10]

Electricity generation in Belize amounted to 433.2 GWh in 2020, with the share of renewable energy sources (RES) including hydropower reaching 90 per cent. Hydropower provided 242.1 GWh (56 per cent) of the total generation, biomass provided 149.5 GWh (35 per cent), thermal power from fossil fuels provided 41.0 GWh (9 per cent) and solar power provided 0.6 GWh (less than 1 per cent) (Figure 2). The relative contribution of the different sources to the electricity supply changed dramatically from 2019, when hydropower provided only 74.7 GWh, while thermal power from fossil fuels provided 137.2 GWh. Major fluctuations in hydropower generation occurred throughout 2018-2020 due to changing hydrological conditions, requiring increasing imports from Mexico as well as generation from thermal power during certain periods. Imports of electricity from Mexico in 2020 amounted to 270.2 GWh, decreasing from 383.7 GWh in 2019.[7,9,10]

Consumption of electricity in Belize in 2020 was 539.3 GWh, representing a decline of over 8 per cent from the 2019 total consumption of 588.4 GWh. Consumption was dominated by the residential and commercial sectors at 245.3 GWh and 249.8 GWh, respectively, with industry and street lighting accounting for the remaining 44.1 GWh.[7,9,10] Overall electricity access in the country was estimated at 93 per cent in 2019, without taking into account consumers connected to off-grid generation sources.[11] Such off-grid systems are known to exist but have not yet been accurately documented. Rural access to electricity in 2019 was estimated at 88 per cent (Figure 3).[12]

Figure 3. **Electrification Rate in Belize in 2019 (%)**



Source: World Bank[12]

As the national utility, Belize Electricity Limited (BEL) is one of the largest single stakeholders in the energy sector of Belize and the only entity in the country with the legal mandate for transmission and distribution of electricity. In addition to owning and operating most grid infrastructure, BEL is a major power producer, operating the Westlake Sub Gas Turbine power plant, the Caye Caulker diesel power and mobile generators with a combined installed capacity of 32.5 MW.[6,7] As of 2020, generation contractors supplying electricity to the BEL national grid system included Santander Sugar Energy Limited (SSEL) and Belize Cogeneration Energy Ltd. (BELCOGEN) using bagasse, Blair Athol Power Company Ltd. (BAPCOL) using heavy fuel oil and Hydro Maya Limited. These entities are regulated by the Public Utilities Commission (PUC). Other independent power producers include the Belize Electric Company Limited (BECOL), which operates hydropower plants, as well as a number of small-self generators like the Farmers Light Plant Corporation in the Spanish Lookout Mennonite Community and the University of Belize solar power plant, which do not currently fall under the PUC regulatory umbrella and are regulated by other national government bodies.[8]

Since its commissioning in 2001, the PUC has been the regulatory body responsible for the electricity, water and telecommunication sectors in Belize. The PUC aims to hold the utilities to a high standard by providing high-quality services at a reasonable cost to consumers. The Directorate of Electricity within the PUC was formed by the Government in order to focus on the regulation of all entities that are licensed under the Belize Electricity Act (2000). Major activities undertaken by the Directorate include: annual review of tariffs and full tariff review every four years for the BEL; licence compliance audits; and reliability and efficiency review for licences held by BEL as well as those issued to field technicians hired by BEL. The purpose of license review is to ensure service quality and consistency within the relatively small Belize energy sector, as a supply deficit from even one power provider could have serious ramifications for electricity access in the country.[13]

Another key stakeholder in the electricity sector is the Ministry of Public Utilities, Energy and Logistics, which oversees the Energy Unit of Belize. The role of the Energy Unit comprises the development of policies, strategic direction and plans for the national energy sector as well as oversight of all matters related to energy and the country's public utilities.

All major load centres across Belize are connected to BEL's national grid system. BEL operates a transmission line backbone consisting of 115 kV and 69 kV lines, running in a north-south direction across the country and interconnected with the Mexican national electricity grid in the north. The 115 kV transmission line covers the entire northern and western zone of Belize, while the southern half of the country is fed via the 69 kV transmission line and 34.5 kV circuits feed the 115 kV backbone to transport electricity to Corozal, Orange Walk and San Pedro. Currently, Caye Caulker and the Spanish Lookout community remain as isolated load centres supplied with electricity by off-grid thermal power plants running on diesel and crude oil.[7]

Table 1. **Electricity Tariffs in Belize**

Category	*Tariff (USD/kWh)*	*Demand charge (USD)*	*Minimum/service charge (USD)*
Social	0.110	N/A	2.50
Residential	0.165–0.215	N/A	5.00
Commercial 1	0.165–0.215	N/A	5.00
Commercial 2	0.190–0.205	N/A	75.00
Industrial 1	0.150	17.91	125.0
Industrial 2	0.130	11.50	125.0
Street lights	0.225	N/A	N/A

Source: BEL[14]

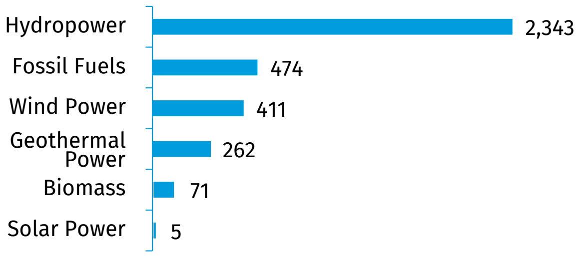
Note: Tariffs valid for the period July 2021–June 2024.

Electricity tariffs for final consumers include a minimum charge and a block charge based on consumption volume for social, residential and commercial consumers and charges based on demand and consumption for industrial consumers. Rates valid for the period from 1 July 2021 to 30 June 2024 are displayed in Table 1.

SMALL HYDROPOWER SECTOR OVERVIEW

There is no national definition of small hydropower (SHP) in Belize. Under the up to 10 MW definition of SHP, there were just two SHP plants in the country as of 2020, with a total installed capacity of 10.3 MW.[7] Additional undeveloped potential capacity is estimated at 11.4 MW, indicating that 48 per cent of the country's SHP potential has been developed so far.[15] Neither installed nor estimated potential capacity have changed relative to the World Small Hydropower Development Report (WSHPDR) 2019 (Figure 4).[16] Existing SHP plants in Belize are listed in Table 2.

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Belize (MW)**



Source: Energy Unit,[7] PÖYRY,[15] WSHPDR 2019,[16] WSHPDR 2013,[17] WSHPDR 2016[18]

Table 2. **List of Existing Small Hydropower Plants in Belize**

Name	*Location*	*Capacity (MW)*	*Generation in 2019 (GWh)*	*Generation in 2020 (GWh)*	*Plant type*	*Operator*	*Launch year*
Chalillo	Maya Mountains, Western Belize	7.0	6.86	29.03	Reservoir	BECOL	2005
Hydro Maya	Southern Belize	3.3	9.96	13.48	Run-of-river	Hydro Maya Ltd.	2003

Source: Energy Unit[7,9,10]

The most recent study of the hydropower potential in Belize was carried out in 2006. The study identified a number of promising sites for hydropower development, including sites on the Macal River and its tributaries with potential capacities of between 2.0 MW and 8.4 MW, a 1 MW site on the Privassion River and potential low-head sites along the Mopan River with a total maximum potential capacity of 15–20 MW.[15] Additional potential hydropower sites have been identified near Chiquibul as well as on the Monkey River and South Stann Creek, but no reliable estimates of potential capacity are available.[16]

RENEWABLE ENERGY POLICY

Renewable energy development targets are outlined in the Energy Policy of Belize as well as in the Nationally Determined Contribution (NDC) under the United Nations Framework Convention on Climate Change (UNFCCC), last updated in 2021. The NDC established the goal of cutting 44 kilotons of CO_2 emissions annually and the target of a 75 per cent share of RES in the national electricity supply by 2030. These targets are to be met in part through an expansion of RES capacities, including an additional 19 MW of installed hydropower capacity.[4]

In 2019, a Consolidated Project Plan (CPP) was developed and published as a collaboration between national stakeholders and the Caribbean Center for Renewable Energy and Energy Efficiency (CCREEE). The CPP provides a consolidated framework for streamlining policy targets and utility goals and incorporates RES targets established under the earlier versions of the NDC. The CPP represents a tool for further planning pertaining to both energy efficiency and renewable energy as well as for identifying opportunities within the electricity sector that offer significant economic, social and environmental benefits for the citizens of Belize.

Additional steps supporting the diversification of the energy mix of Belize and the development of hydropower in particular included the 2013 Request for Proposals (RFP) to secure adequate electricity generation or supply capacity to satisfy electricity demand in the country for the next 15 years at least cost, to be submitted through a competitive bidding process. The issued RFP targeted not only the addition of new generation capacities from RES, but also the gradual replacement of high-cost thermal generation with RES generation where possible.[19] However, no new SHP capacity was added under the 2013 RFP, and no new RFPs are being planned as of 2022.[8]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The only in-country programme that could be considered as a financial mechanism available for SHP development is a loan initiative from the Development Finance Corporation (DFC) targeted towards homeowners and businesses for the promotion of RES in the private sector. The scope of the financing available through this scheme with regard to utility- or grid-scale plants is limited.[8]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

In both 2018 and 2019, Belize experienced an intensified dry season resulting in severe droughts, which damaged the agricultural sector and reduced the supply of electricity from hydropower as well as from biomass-fired power plants. These conditions necessitated a greater dependence on imports of electricity from Mexico, which directly corresponded to an increase in the cost of power for grid consumers in Belize.[20]

BECOL, in adjusting to the increasing volatility of hydropower generation, is developing plans to diversify its feed to the grid by adding utility-scale solar power systems to its generation mix. Generally, the effect of climate change on generation from RES is marked and will require careful planning to sustainably pursue further development.[8]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In summary, while Belize possesses both operational SHP plants and potential for further SHP development, there are currently no defined plans in place to further develop the SHP sector, largely due to natural challenges and lack of incentives and investment.

Some barriers to SHP development in the country are:

- Increasing volatility of rainfall and hydropower potential due to climate change effects;
- Some negative environmental impacts have been observed, including elevated levels of metals in river fish, that are attributed to hydropower in general rather than specifically to SHP;
- No plans other than the NDC goals are currently in place to expand SHP;
- No financial incentives, allotted funds or large-scale investments are readily available for SHP projects.

Enablers for SHP development in Belize include:

- More than half of the identified SHP potential in the country is still undeveloped;
- The hydropower potential is recognized in the NDCs and other government policies;
- The hydropower and SHP technology is mature and already in use in the country;
- International funding and loans could be pursued to supply financial resources for SHP, as precedents exist for other RES.

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Costa Rica

Marco Antonio Jiménez Chaves, Costa Rica Electricity Institute; Laura Lizano Ramón, Energy Sector Planning Secretariat, Ministry of Environment and Energy

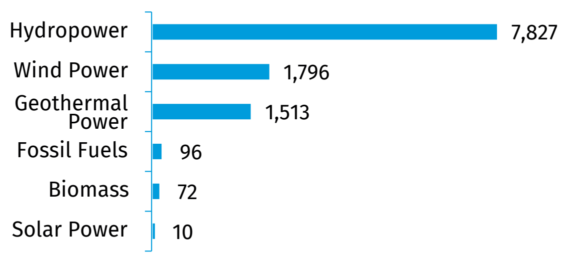
KEY FACTS

Population	5,111,238 (2020)[1]
Area	51,100 km^2 [1]
Topography	The topography is irregular, with valleys, mountain ranges and plains. Three main mountain ranges run in the longest direction, from north-west to south-east, descending towards the coastal plains and dividing the country into two slopes — the Pacific and the Caribbean. In the north-west, the Guanacaste and Tilarán Volcanic Mountain Ranges have the lowest peaks. In the centre of the country, the Central Volcanic Mountain Range forms the Central Valley. It is the most urbanized area in the country, where the capital city, San Jose, is located. The Talamanca Mountain Range lies in the south-east, with the highest peaks. Mount Chirripó is the highest mountain in Costa Rica with an elevation of 3,819 metres.[2]
Climate	Costa Rica lies within the tropical zone, between the Tropics of Cancer and Capricorn. The tropical climate is influenced by the topographic, oceanic, isthmus location and general atmospheric circulation factors. The average annual temperature is 25 °C. The country is divided into three general climate regions. The Tropical Caribbean Wet Region with monthly mean extreme temperatures between 22 °C and 31 °C. The Central Intermontane Region, with monthly mean extreme temperatures between 13 °C and 27 °C. The Tropical Pacific Region with monthly mean extreme temperatures between 23 °C and 33 °C.[3,4]
Climate Change	Climate change scenarios forecast increased rainfall south of the Caribbean and Pacific regions. Decreased rainfall is expected north of the Pacific and Central regions.[3,4]
Rain Pattern	Annual average accumulated rainfall is 3,297 mm. Different rain patterns occur in the Caribbean and the Pacific slopes. The Caribbean slope is wetter, without a defined dry season, with heavy rainfalls occurring in December and lower rainfalls occurring in February, March, September and October. Annual average accumulated rainfall in the Caribbean highlands reaches values as high as 8,000 mm. The Pacific slope is drier, with defined wet and dry seasons. The former extends between December and March; the latter extends between May and October. April and November are transitional periods. The Northern Pacific is the driest zone with annual average rainfall as low as 1,400 mm in the lowlands.[2]
Hydrology	The territory is divided into 34 main watersheds: 18 in the Caribbean slope and 16 in the Pacific slope. The largest is the Grande de Térraba watershed in the Southern Pacific, with an area of 5,085 km^2. Mean annual river flow in the territory is 70 litres per second (lps) per km^2 of watershed area. The Caribbean and Southern Pacific river flows are as high as 180 lps per km^2 of watershed area. The Grande de Térraba River has the highest mean annual flow, with 340 m^3 per second. The Northern Pacific river flows are lower than 30 lps per km^2 of watershed area.[2]

ELECTRICITY SECTOR OVERVIEW

Electricity generation in Costa Rica in 2019 reached 11,313 GWh, with 99 per cent coming from renewable energy sources, mainly hydropower (Figure 1). Seasonal variation of electricity consumption is minor, slightly higher in the dry season. Domestic electricity demand in 2019 was 11,334 GWh. Net imports within the Regional Electric Market (MER) with Central-American countries fulfilled 21 GWh for domestic electricity demand. The installed capacity in 2019 was 3,566 MW (Figure 2).[5]

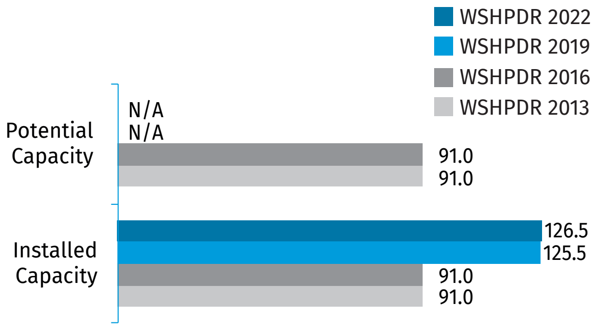
Figure 1. **Annual Electricity Generation by Source in Costa Rica in 2019 (GWh)**



Source: ICE[5]

The share of renewable energy sources in the National Electrical System (SEN) of Costa Rica is highly influenced by hydropower seasonality. During the rainy season, hydropower resources are plenty and SEN run-of-river hydropower plants spill surplus river flows. However, in the dry season hydropower resources are scarce, as a result, run-of-river production decreases significantly and hydropower generation depends on large-scale storage hydropower plants. Energy demand is then fulfilled by geothermal power or other renewable sources whose availability increases precisely in this season. Wind power and sugar cane bagasse biomass as well as endorsement from fossil fuel thermal power plants are required in a minor proportion.

Figure 2. **Installed Capacity by Source in Costa Rica in 2019 (MW)**



Source: ICE[5]

National electrification rate in 2019 was 99.4 per cent of total occupied dwellings.[6] Electricity demand grew by 1.9 per cent in 2019 compared to 2018.[5] The Energy Transition Index Report 2019 ranked the performance of the energy system of Costa Rica among the top 10 countries worldwide.[7] The public company, Costa Rica Electricity Institute (ICE), guarantees the electricity supply needed for the country's development, as mandated by Law 449.[8] ICE produces most of the electricity in the country, manages the transmission system and most of the distribution lines. Furthermore, the company is responsible for the planning and overall operation of the SEN. In 2019, ICE generated the biggest share of total electricity supply, accounting for almost 64 per cent. The share of public services distribution companies stood at 12 per cent. The private sector generation contributed 24 per cent.

Transmission lines extend widely, between the borders with Nicaragua and Panama and the Caribbean and Pacific coasts, totalling 1,725 km for 230 kV lines and 654 km for 138 kV lines. The Central American Electric Interconnection System (SIEPAC), which was completed in 2014, is the backbone of MER, which is operated by Ente Operador Regional (ORG).[9] In 2019, energy transactions within MER reached 3,074 GWh, the highest transaction volume since the establishment of MER.[10]

The main power production zone in the country is in the Northern Pacific, with hydropower plants located on rivers flowing towards the Caribbean, wind farms, geothermal fields, biomass and solar power plants.[11] The Central Valley is the main consumption zone. Distribution lines are managed by eight public services distribution companies, including ICE.[12] In 2017, an overload in the SIEPAC transmission line on the Panama side caused the most recent outage in Costa Rica. Before 2017, SEN had accomplished 10 years of service without outages.[13]

The long-term planning for the SEN is defined by ICE, in its Electric Generation Expansion Plans. For the 2018–2035 period, electricity demand is estimated to increase annually by 1.8–2.4 per cent. Capacity additions will be based entirely on renewable energy technologies.[12]

Electricity prices in Costa Rica are regulated, with no subsidies. The Public Services Regulatory Authority (ARESEP) defines methodologies for setting the tariffs. Prices differ according to the public services distribution company and the sector. The electricity prices in Costa Rica experience strong variations between the wet and dry season. The lowest annual average electricity price in 2020 was 0.09 USD/kWh for the commercial and services sector with consumption above 3,000 kWh. The highest annual average price was 0.27 USD/kWh for the industrial sector with consumption below 3,000 kWh.[14]

SMALL HYDROPOWER SECTOR OVERVIEW

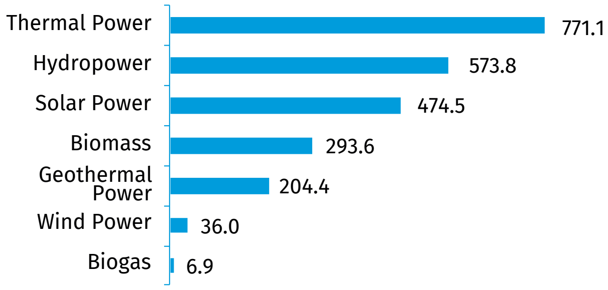
There is no official local definition for small hydropower (SHP) in Costa Rica. Law 7200 defines that the private sector and cooperative companies can produce autonomous energy with limited capacity power plants (LCP) defined as hydropower or non-conventional plants with capacity up to 20 MW.[9]

In 2020, there were 37 SHP plants (up to 10 MW) in operation in Costa Rica, with a combined installed capacity of 113.3 MW. The total installed capacity of SHP up to 10 MW in the country was 126.5 MW, including four inactive SHP plants or plants with an unknown status, increasing from 125.5 MW in 2018. The 2020 investigation for the current edition of the World Small Hydropower Development Report (WSHPDR) found that no decommissioning or construction of new SHP plants was held since the previous edition (Table 1). The minor changes in installed capacity are due to a new data review (Figure 3).[5,15]

The majority of SHP plants in the country are connected to the grid. Off-grid SHP plants with a capacity of 1–10 kW are used for self-supply or in remote national parks, providing electricity support for the Ministry of Environment and Energy (MINAE) environmental protection tasks, for instance in the Cocos Island and Mount Chirripó National Parks. Public services distribution companies and private owners hold most of the operational SHP capacity, 64 per cent and 31 per cent, respectively, while ICE holds 5 per cent. The National Lighting Company (CNFL), which is the Central Valley public services distribution company and an ICE subsidiary, owns most of the oldest SHP plants in the country. Some of these plants date back to the early 20th century and, thus, require refurbishment.[16]

The investigation for the current Report found that in 2020 there were 50 limited capacity hydropower plants (up to 20 MW) in operation with a combined capacity of 328.7 MW. The total installed capacity of SHP up to 20 MW was 353.2 MW, including five inactive and unknown status plants, increasing from 352 MW in 2018.[15,16] The minor changes in installed capacity since the WSHPDR 2019 are due to a data review.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Costa Rica (MW)**



Source: ICE,[5] WSHPDR 2019,[15] WSHPDR 2013,[17] WSHPDR 2016,[18] Hoes et al.[19]

Note: Data for SHP up to 10 MW.

Table 1. **List of Selected Operational Small Hydropower Plants in Costa Rica**

Name	*Installed capacity (MW)*	*Operator*	*Launch year*
Suerkata	2.7	Private	1995
Rebeca I	0.1	Private	1995
Rio Lajas	10.0	Private	1997
Poás I y II	1.9	Private	1997
El Embalse	1.5	Private	1997
Río Segundo II	1.0	Private	1998
Chocosuela I	8.0	COOPELESCA	1999
Caño Grande III	3.3	Private	1999
Peñas Blancas Mini Hydro	0.4	ICE	2002
Cote	7.0	CNFL	2003
Chocosuela III	5.0	COOPELESCA	2003
Genio	0.03	MINAE	2005
Páramo	0.01	MINAE	2008
El Encanto	8.0	CNFL	2009
El Ángel	3.4	Private	2012
Vara Blanca	2.5	Private	2012
Tacares	7.0	ESPH	2013
Olivier	0.01	MINAE	2015
El Angel Ampliación	5.6	Private	2016
Matamoros	3.6	Private	2016

Source: ICE,[9,12] CENCE[16]

No official local estimate of SHP potential exists for the country. ICE reports 7,651 MW as the total identified hydropower potential capacity, regardless of the plant size. In this Report, the identified hydropower potential regardless of plant size is assumed as the technical potential. Installed capacity accounts for 30 per cent of the estimated technical hydropower potential. Nearly 35 per cent of the undeveloped hydropower potential is concentrated in indigenous territories and 20 per cent in national parks and reserve forest.[12]

Similar to the WSHPDR 2019, the theoretical SHP potential capacity data come from the systematic high-resolution assessment of worldwide hydropower potential by capacity.[19] Total theoretical SHP potential capacity of Costa Rica is 7,373.5 MW, which is 28.9 per cent of the country's total theoretical hydropower potential capacity, regardless of plant size, totalling 25,535.9 MW.[19] The estimated value coincides with the total theoretical hydropower potential capacity, reported by ICE.[12]

The 2018–2034 Electric Generation Expansion Plan considered the addition of three private SHP plants totalling 19 MW for SEN in 2021.[12] However, due to environmental disputes, the projects were not executed.[20] In the last years, some municipal councils are becoming increasingly concerned about the environmental impact of hydropower and have even signed moratoriums on hydropower developments in their territories, including SHP.[21] The central Government has also signed a moratorium on hydropower development in high potential watersheds.[22]

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

The 2020 investigation for the current Report found 52 MW of SHP projects in the feasibility stage: 33 MW from public distribution service companies and 19 MW from private SHP projects with environmental disputes as stated before (Table 2). Private SHP project capital expenditure (CAPEX) ranges between 3,500 USD/kW and 3,800 USD/kW.[12] Two other potential SHP projects for future development are Rio Piedras and PAAM, which are part of other short-term water use infrastructure plans. The Rio Piedras project consists of a 7 MW powerhouse at the toe of a 40-metre-high dam that creates a 70 hm^3 reservoir. The civil works are part of the Rio Piedras Multipurpose Project, a water storage project for crops irrigation and water supply in the Northern Pacific region.[23] The PAAM project consists of a 2.6 MW powerhouse installed in a new water supply pipe, for the Fifth Expansion Stage of the Metropolitan Water Supply System (PAAM).

Table 2. **List of Selected Small Hydropower Sites Available for Development in Costa Rica as of 2021**

Name	*Potential capacity (MW)*	*Type of site*
Futuro	10.0	New
Toro Amarillo 1	8.0	New
Llano Bonito	1.0	New
Rio Piedras	7.0	New
PAAM	2.6	New

Source: ICE,[9,12] CENCE[16]

RENEWABLE ENERGY POLICY

At the international level, Costa Rica has committed to the Paris Agreement and in 2020 updated its Nationally Determined Contributions (NDC), with higher ambitions for 2030. Costa Rica has also committed to adopt integrated climate actions, including mitigation and adaptation for 2030. Moreover, the country seeks to achieve the 2030 Agenda for Sustainable Development, with actions leading to increase the share of renewable energy in the overall energy mix, ensure energy access and increase energy efficiency (Sustainable Development Goal 7).

The national renewable energy policies of Costa Rica are defined in the National Energy Plans, under the guidelines of the National Development Plan established by the Government. The main objective of the current VII National Energy Plan 2015–2030 is to achieve energy sustainability with low carbon emissions. The Plan contains short-, medium- and long-term goals, with defined time limits and responsible institutions.[24] The VII National Energy Plan 2015–2030 was updated in 2019, considering new policies, regulations and plans for the energy sector. These include the Organization for Economic Co-operation and Development (OECD) accession recommendations, National Decarbonization Plan 2018–2050, National Development and Public Investment Plan 2019–2022, Law 9518 on Incentives and Promotion for Electric Transportation, National Electric Transportation Plan 2018–2030, energy sector audits, current guidelines and stakeholders' proposals.[25]

The National Decarbonization Plan 2018–2050, launched in 2019, states a net zero emissions economy goal for 2050.[26] This plan outlines the way of transforming the economy of Costa Rica towards a development model based on bioeconomy, green growth, inclusion and the improvement of the quality of life of the citizens. For the energy sector, this means electrification of the transport and industrial sectors, which is expected to cause an increased electricity demand to be met via a resilient and low-cost electricity system.

In compliance with the National Energy Plan, ICE creates Electric Generation Expansion Plans. ICE planning for the electricity sector focuses on the pursuit of sustainable development, ensuring low use of fossil fuels, diversifying renewable energy sources, fomenting MER and lowering the cost of electricity. Planned capacity investments for the 2018–2035 period include mostly renewable sources, adding up to 653 MW: 286 MW from wind power projects, 165 MW from geothermal power, 155 MW from solar power and 47 MW from hydropower, including 19 MW from private SHP projects currently discarded due to environmental disputes. The main changes from previous Electric Generation Expansion Plans are due to the downward trend of electricity demand.[12]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

In 1990, Law 7200 authorized autonomous or parallel generation, defined as electricity produced from private and public cooperative companies with LCP plants, defined as hydropower plants or plants based on non-conventional sources with lower than 20 MW capacity. Fossil fuel thermal plants, coal or large-scale hydropower are defined as conventional sources, whose development is planned by ICE according to Law 449 and national energy policies. Law 7200 regulates Build-Own-Operate (BOO) contracts signed between ICE and local or foreign private investors, which include power purchase agreements (PPA) for a period of 20 years. BOO contracts are capped to 15 per cent of total electricity production.[9] Law 7508 increased the cap of private generation by an additional 15 per cent in 1995, through Build-Operate-Transfer (BOT) contracts. Similar to BOO contracts, BOT contracts include power purchase agreement (PPA) for 20 years.[27] As stated by Law 7200, ICE buys electricity from BOO and BOT contracts, according to the ARESEP tailored tariffs for these plants. The size of power plants is regulated by Law 7200: 20 MW maximum capacity under BOO contracts and 50 MW maximum capacity under BOT contracts with local and foreign private investors.[5,28]

The licensing process for BOO contracts is defined in Law 7200. ICE calls for LCP bids in compliance with the Electric Generation Expansion Plan. Private investors interested in hydropower LCP development submit eligibility applications. Licensing approval requires an ICE declaration of eligibility, a granted concession from the Water Department of the Ministry of Energy, a granted concession from ARESEP and the National Technical Environmental Secretariat (SETENA) declaration of an Environmental Viability Licence. An Environmental Viability Licence is granted following a staged procedure. Depending on the impact evaluation required in each stage of the process, the projects advance to further stages requiring more details on the environmental impacts and countermeasures. Existing and old plants are subjected to the same process.[29]

For BOT contracts ICE also calls for bids in compliance with the Electric Generation Expansion Plan. BOT contracts are assigned through public bidding with price competition and technical, economic and financial capacity evaluations of the bidders.[9] In 2003, Law 8345 authorized public services distribution companies to use available energy sources in the country for meeting the electricity demand in their coverage areas. The licensing process for public services distribution companies is defined by Law 8345. The main requirements are a granted concession from the MINAE Water and Energy Departments for projects with less than 60 MW of capacity and a SETENA declaration of an Environmental Viability Licence.[30]

Since the global financial crisis in 2008, the electricity demand has demonstrated a downward trend, mainly due to economic factors. Several projects already defined between 2008 and 2015 were commissioned, leading to a surplus capacity that can support the country's electricity demand up to 2026, according to the Electric Generation Expansion Plan. Directive No. 68-MINAE for the energy sector was published in August 2020 to prevent electricity costs from rising. According to this Directive, the Ministry of Energy would not grant concessions or environmental permits for any type of new power projects for a one-year period to avoid an excessive installation of generating capacities, which could result in increased service costs.[31]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

In Costa Rica, SHP projects financing has been made by public and private commercial banks, national and international, as well as through trust funds. For projects regulated under Law 7200, loans above maximum credit limits for commercial banks can be authorized by the Central Bank of Costa Rica (BCCR). Tax exemption applies to imported machinery, waterway equipment and all equipment required for electricity generation.[9] For projects regulated by Law 8345, loans exceeding USD 10 million per year can be authorized by BCCR. The same tax exemptions apply to Law 7200.[28] Moreover, several SHP plants were also financed by the Kyoto Protocol Clean Development Mechanism (CDM). Furthermore, Costa Rica participates in the Guacamaya SHP project funded under the CDM.[32]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The Inter-American Development Bank (IADB) published in 2016 a study about growing hydropower vulnerability in Central America due to climate change. The study focused on climate change effects for the seven main hydropower plants of the region, one for each country. Based on the climate change models of the Intergovernmental Panel on Climate Change (IPCC) and the projected changes in inflows, the study forecasted for the 305 MW Reventazón hydropower plant in Costa Rica a 2.3 per cent increase in generation in 2030 and a 13.9 per cent decrease in generation in 2090. The corresponding economic impact is estimated to be between USD 22 million and USD 244 million.[33]

Similarly, local preliminary studies indicate that climate change (i.e., increased rainfall south of the Caribbean and Pacific Regions or decreased rainfall in the north of the Pacific and Central Regions) could generate losses for SEN of between USD 200 million and USD 314 million yearly. Generation by fossil fuel thermal plants could reach 15 per cent of total electricity generation in 2080 if the country does not harness local renewable energy sources.[34] The natural inflow energy from the SEN hydropower sources turned out to be the lowest in 2019, taking into consideration all available water inflow data since 1965.

Costa Rica has not defined any official adaptation measures for the SHP sector. However, for large-scale hydropower, ICE focuses on sediment management, to preserve reservoir capacities in the long term.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Nowadays, the SHP sector in Costa Rica represents 5 per cent of installed hydropower capacity and is mainly owned by private and public service distribution companies. In the last decades, SHP has constantly contributed to the electricity sector of the country. However, the future development of SHP is expected to encounter more limitations than in the past. According to the authors, the main barriers for future SHP development in Costa Rica are:

- Environmental: The municipal and Government moratoriums on hydropower development in high-potential watersheds were put in place due to environmental concerns of the impact of SHP.
- Run-of-river seasonality: Currently, the share of renewable energy in the energy mix is highly influenced by the hydropower generation pattern. SHP plants are mainly run-of-river, thus, producing surplus electricity in the rainy season and providing less electricity in the dry season. Therefore, diversification of the energy mix is required for providing renewable electricity during the low season of hydropower generation.
- The improved competitiveness of solar and wind power projects: Solar and wind power projects have seen their CAPEX plummet dramatically in the last decade. Additions of these resources may reduce the operational marginal costs of SEN during the low season of hydropower generation, thus reducing the overall operating expenses (OPEX) of the SEN.
- Downward trend of the electricity demand: Electricity demand has been very low in the last years in Costa Rica. The existing installed capacity is enough for meeting the demand for the next years, therefore, there will be no need for new projects until 2026. To prevent electricity costs from rising, Directive No. 68-MINAE, published in August 2020, dictates that MINAE must not give concessions, nor environmental permits for any type of new power projects for a one-year period.

According to the authors, the main enablers for future SHP developments are:

- Technical know-how: Through the installed hydropower capacity and over 60 years of its existence, the sector accumulated strong experience with high-skilled staff, companies and all the necessary features for future environmentally sustainable and cost-effective hydropower development.
- SHP potential: There is a significant untapped potential for the development of SHP projects, which represents a sustainable way to harness the untapped hydropower potential in the country.
- Renewable energy policies: Energy policies encourage the development of renewable energy projects. Environmental and cost-competitive SHP projects (e.g.,

projects that can take advantage of existing and/or multipurpose planned facilities) may be interesting to fulfil the renewable energy share.

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El Salvador

Juan José García Méndez and Victor Sagastume, National Council of Energy

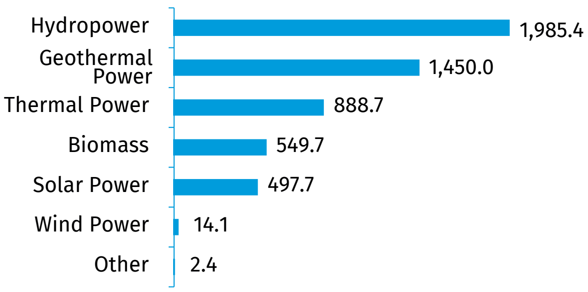
KEY FACTS

Population	6,704,864 (2019)[1]
Area	21,040.8 km² [1]
Topography	The topography of El Salvador is dominated by parallel mountain ranges stretching from east to west and separated by a central plateau, which together comprise 85 per cent of the territory of the country. A narrow coastal plain extending to the Pacific Ocean accounts for the remaining 15 per cent. The highest point in El Salvador is Santa Ana in the southern mountains, at 2,365 metres above sea level.[2]
Climate	The climate in El Salvador is tropical and is characterized by two seasons — a dry season from November to April and a rainy season from May to October. The annual average temperature is estimated at 26 °C. During summer, temperature usually varies between 26 °C and 30 °C, while in winter it only drops to approximately 21 °C to 24 °C.[3]
Climate Change	Climate change models predict a rise in temperatures of 1.5–2.0 °C by 2040–2050 and of 2.5–4.5 °C by 2091–2100, relative to the 1961–1990 baseline period. The eastern parts of the country are expected to experience the most significant increases in temperature. Rainfall is expected to decrease by as much as 20–35 per cent by the end of the century.[4]
Rain Pattern	Average annual precipitation in El Salvador is 1,865 mm and can reach 2,000 mm in certain mountainous parts of the country. The variation in rainfall between the driest and the wettest months is approximately 227 mm.[2,3]
Hydrology	El Salvador has 11 hydrographic regions that are delimited by the basins of the country's main rivers. One of the most important is the Lempa River region, with an area of 10,082 km², which represents approximately 48 per cent of the national territory.[5]

ELECTRICITY SECTOR OVERVIEW

The total installed electricity capacity of El Salvador was 2,360.2 MW in 2020. Thermal power from fossil fuels provided 771.1 MW (33 per cent) of the total, hydropower provided 573.8 MW (24 per cent), solar power provided 474.5 MW (20 per cent), biomass provided 293.6 MW (12 per cent), geothermal power provided 204.4 MW (9 per cent), wind power provided 36.0 MW (2 per cent) and biogas provided 6.9 MW (less than 1 per cent) (Figure 1).[6]

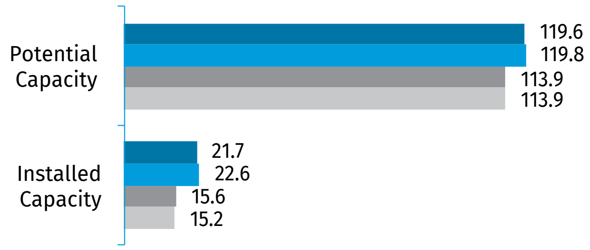
Figure 1. **Installed Electricity Capacity by Source in El Salvador in 2020 (MW)**



Source: SIGET[6]

Generation of electricity in 2020 amounted to 5,387.9 GWh. Hydropower contributed 1,985.4 GWh (37 per cent) of the total, geothermal power contributed 1,450.0 GWh (27 per cent), thermal power from fossil fuels contributed 888.7 GWh (16 per cent), biomass contributed 549.7 GWh (10 per cent), solar power contributed 497.7 GWh (9 per cent), wind power contributed 14.1 GWh (less than 1 per cent), and other sources contributed an additional 2.4 GWh (less than 1 per cent) (Figure 2). Total electricity generation increased by nearly 4 per cent relative to 2019. Generation from solar power increased nearly 130 per cent, while generation from fossil fuels decreased by approximately 45 per cent.[6] Approximately 85 per cent of electricity generation in 2020 was provided by renewable energy sources (RES), but this figure varies from year to year due to differences in weather, particularly in rainfall. The gap between generation from biomass and installed capacity of biomass-fired power plants is explained by the fact that biomass (bagasse) fuel is sourced from sugar cane and the plants operate only during the sugar cane harvest season between November and April rather than year-round.

Figure 2. **Annual Electricity Generation by Source in El Salvador in 2020 (GWh)**



Source: SIGET[6]

The electricity grid of El Salvador is composed of the high-voltage transmission network (above 115 kV) and the mid/low-voltage distribution network (below 115 kV). The transmission network in 2020 consisted of 41 115 kV lines with a total length of 1,073 kilometres, 24 substations and four 230 kV lines that interconnect the transmission system of El Salvador with that of Guatemala (14.6 kilometres) and Honduras (92.9 kilometres). The distribution of electricity is carried out by eight different companies supplying energy at different voltages. The overall length of the distribution lines is over 48,000 kilometres and the system supplied electricity to 1,907,939 end users as of the end of 2020.[6]

Access to electricity in El Salvador in 2020 was nearly 98 per cent nationwide, 99 per cent in urban areas and 95 per cent in rural areas.[7] Efforts have been started to develop a master electrification plan to provide technically and economically feasible solutions for communities still lacking electricity access. Electricity consumption in 2020 was 5,915.9 GWh, decreasing from 6,361 GWh in 2019 due to the impact of the COVID-19 pandemic, while peak demand reached 1,010 MW. Transmission losses accounted for 1.8 per cent of total electricity supply. Electricity imports covered the gap between domestic generation and total electricity demand and reached 642.6 GWh in 2020, decreasing by 50 per cent relative to 2019.[6]

The electricity market of El Salvador is composed of the wholesale electricity market and the retail electricity market. The wholesale market is constituted by the Long-Term Contracts Market (CLP) and the Spot Market (MRS). In order to participate in it, the installed capacity of a power plant must be at least 5 MW and it can be connected to either the transmission or distribution network. To participate in the retail electricity market, the installed capacity of the power plant must be less than 20 MW and it can only be connected to the distribution network. Bilateral contracts can be signed in both markets (power purchase agreement), to commercialize the electricity generated.[8]

El Salvador is additionally part of the Regional Electricity Market (MER), which operates under the Framework Treaty of the Central American Electricity Market, approved by Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama in May 2000. Its general design conceptualizes the MER as a seventh market. The six existing country markets or national systems have agents authorized by the Regional Operator Entity (EOR) and carrying out international electric power transactions in the Central American region.[9] All member countries are interconnected through the Central American Electrical Interconnection System (SIEPAC) transmission network.

Historically, as in many other countries in Latin America, the energy sector in El Salvador was first developed by the state. The electricity market was vertically integrated, with the activities of generation, transmission, distribution, commercialization and long-term planning of the energy sector being controlled and regulated by the state. Due to several policies implemented by the Government in the 1990s, the electricity market, among others, underwent reforms of laws and regulatory frameworks. As a result of these reforms, the electricity market became open to private investment and therefore changed to a competitive market. Its growth and development were driven by demand, which resulted in the state losing its role in the planning and strategic development of the sector.[9]

The first component of this reform was the approval of the Law of Creation of the General Superintendence of Electricity and Telecommunications (SIGET) and the General Law of Electricity. Both laws were approved by the Congress in 1996. The role of regulator of the electricity and telecommunications market was given to SIGET.[9]

The second component consisted of dissolving the state companies that operated the electricity sector. The activities of power generation, transmission, distribution, commercialization and operation of the electricity system were privatized. The National Council of Energy (CNE) was created in 2007, in an attempt to reinstate the strategic planning role of the state. CNE started operations in 2009 and established the National Energy Policy 2010–2024.[9] Aiming to accelerate the energy transition in El Salvador, in 2021 the CNE presented the new National Energy Policy 2020–2050, which includes the following strategic goals: regulatory modernization; sustainable energy supply; efficient energy consumption; research, development and innovation; and energy security and integration.[10]

The CNE is constituted by the ministers or vice-ministers of the government departments related to the different aspects of the energy sector's development, including the Ministry of Economy, the Technical Secretariat of the Presidency, the Ministry of Treasury, the Ministry of Public Works, the Ministry of Environment and Natural Resources and the Consumer Protection Agency.[9]

In addition to the CNE, the electricity sector is composed of the following agents:

- Electricity generating companies;
- The transmission agent (ETESAL), a private company responsible for the planning of the expansion, construction of new extensions and maintenance of the national transmission network;

- Private electricity distribution companies operating the low-voltage distribution networks;
- Electricity traders, private or public agents that perform selling and buying transactions in the domestic and regional electricity market to meet the demands of any other agent, including final users;
- The Transaction Unit (UT), an independent market and system operator in charge of operating the transmission system, maintaining the security of the system, ensuring a defined minimum quality of the services and supplies and also operating the wholesale electric power market;
- The SIGET is the regulatory entity responsible for applying the laws and regulations that govern the electricity and telecommunications sectors in the country.

The end user's electricity bill in El Salvador includes three charges: an energy charge, distribution charge and marketing charge. The energy charge is approximately 80 per cent of the bill and is adjusted quarterly based on Article 90 of the General Electricity Law Regulations. The adjustments are made on 15 January, 15 April, 15 July and 15 October of each year. The average unsubsidized prices of the electricity tariff to end users for the first semester of 2020 are presented in Table 1. The electricity subsidy applies to residential users with a monthly consumption of 1–105 kWh, for a value of USD 5.00 per month. For industrial consumers, the energy charge is calculated based on power level and not on consumption.

Table 1. **Electricity Tariffs in El Salvador in 2020**

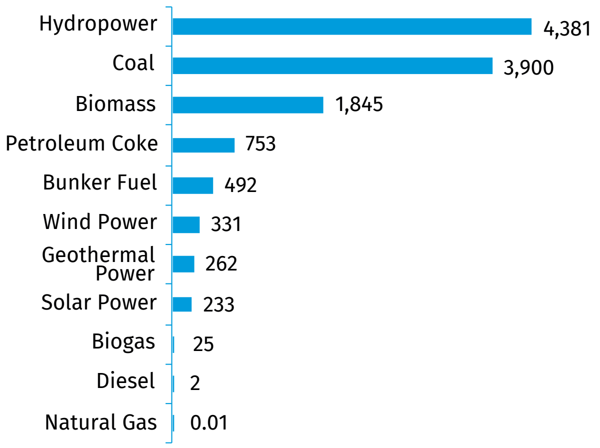
Tariff category	*Semiannual average price (USD/kWh)*
Low voltage:	
Total residential average	0.2018
General use	0.1773
Public lighting	0.1636
Medium demand (10–50 kW)	0.2234
High demand (> 50 kW)	0.2015
Medium voltage:	
Medium demand (10–50 kW)	0.1617
High demand (> 50 kW)	0.1442
Overall average price of distributors	0.1721

Source: SIGET[6]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in El Salvador is a hydropower plant with an installed capacity off less than or equal to 5 MW.[11] The total installed capacity of SHP up to 5 MW in El Salvador was 21.7 MW in 2020; however, there are no SHP plants in the 5–10 MW range in the country, so the installed capacity for SHP up to 10 MW is the same. In addition, there are two non-operational plants with a combined capacity of 0.625 MW.[12] The potential undeveloped capacity for SHP up to 10 MW has been estimated at 97.3 MW by previous publications and for SHP up to 20 MW at 157.6 MW.[12,13,14] The total SHP potential up to 10 MW, including existing operational and non-operational plants and undeveloped potential, can therefore be estimated at 119.6 MW. Relative to the World Small Hydropower Development Report (WSHPDR) 2019, the installed capacity of SHP plants up to 10 MW decreased by approximately 4 per cent, while the estimate of potential capacity decreased by less than 1 per cent, in both cases due to a reassessment of the installed capacities and operational status of several existing plants (Figure 3).[13]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in El Salvador (MW)**



Source: García Méndez & Sagastume,[12] WSHPDR 2019,[13] JICA,[14] WSHPDR 2013,[15] WSHPDR 2016[16]

Note: Data are for SHP up to 10 MW.

A list of existing operational SHP plants in El Salvador is provided in Table 2. The current status of two previously operational plants, the 600 kW Atehuasías SHP plant and the 25 kW La Chacara SHP plant, is unclear, but they are likely inactive and in need of rehabilitation.[12] Two ongoing SHP projects on the San Simón River are listed in Table 3, while a list of several potential SHP sites available for investment is displayed in Table 4.

Table 2. **List of Existing Small Hydropower Plants in El Salvador**

Name	Location (river)	Capacity (MW)	Operator
Río Sucio	Sucio	4.20	COMPAÑIA ELECTRICA CUCUMACAYAN, S.A. DE C.V.
Cucumacayán	Sensunapan	2.80	COMPAÑIA ELECTRICA CUCUMACAYAN, S.A. DE C.V.
Nahuizalco I	Papaloate, Sensunapan, Las Monjas	2.80	SENSUNAPAN, S.A. DE C.V.

Name	Location (river)	Capacity (MW)	Operator
Juayua	Sensunapan	2.47	HIDROELÉCTRICA JUAYUA, S.A. DE C.V.
Papalote	Papalote	2.00	HIDROELECTRICA PAPALOATE, S.A DE C.V.
Milingo	Acelhuate	1.80	COMPAÑIA ELECTRICA CUCUMACAYAN, S.A. DE C.V.
La Calera	Santa Lucia, Calera	1.50	DE MATHEU Y COMPAÑIA, SOCIEDAD ANONIMA DE CAPITAL VARIABLE
San Luis I	Suquiapa	1.31	COMPAÑIA ELECTRICA CUCUMACAYAN, S.A. DE C.V.
Venecia Prusia	Acelhuate	0.75	INDUSTRIAS AGRÍCOLAS VENECIA Y PRUSIA, S.A. de C.V.
San Luis II	Suquiapa	0.74	COMPAÑIA ELECTRICA CUCUMACAYAN, S.A. DE C.V.
Bululú	Sensunapan	0.68	COMPAÑIA ELECTRICA CUCUMACAYAN, S.A. DE C.V.
Cutumay Camones	El Sauce	0.28	COMPAÑIA ELECTRICA CUCUMACAYAN, S.A. DE C.V.
Sonsonate	Sensunapan	0.15	COMPAÑIA ELECTRICA CUCUMACAYAN, S.A. DE C.V.
Velesa Energy	Agua Caliente	0.12	VELESA ENERGY S.A DE C.V.
El Calambre	Calambre	0.06	SANEAMIENTO BÁSICO, EDUCACIÓN SANITARIA Y ENERGÍAS ALTERNATIVAS
Miracapa	San Miguel	0.03	SANEAMIENTO BÁSICO, EDUCACIÓN SANITARIA Y ENERGÍAS ALTERNATIVAS
Junquillo	Quebada El Sirigual	0.02	SANEAMIENTO BÁSICO, EDUCACIÓN SANITARIA Y ENERGÍAS ALTERNATIVAS
Total		**21.71**	

Source: García Méndez & Sagastume,[12] Torres,[17] SIGET,[18,19] Hidroelectrica Juayua,[20] La Información[21]

Table 3. **List of Ongoing Small Hydropower Projects in El Salvador**

Name	*Location (river)*	*Capacity (MW)*	*Developer*
San Simón I	San Simón	0.23	ENSOSAL, S.A. de C.V.
San Simón II	San Simón	0.40	ENSOSAL, S.A. de C.V.

Source: SIGET,[18] IRENA[22]

Table 4. **List of Selected Potential Small Hydropower Sites in El Salvador**

Name	*River*	*Department*	*Potential Capacity (MW)*
El Sapo	Sapo	Morazán	2.4
Santo Domingo (Presa 1)	Tepechapa	Sonsonate	1.5
Santo Domingo (Presa 3)	Cacahuata	Sonsonate	1.5
Santo Domingo (Presa 2)	Quebrada El Camote	Sonsonate	1.5
Río Rosario - Metapan	Rosario	Santa Ana	1.0

Source: JICA[14]

RENEWABLE ENERGY POLICY

One of the strategic guidelines of the National Energy Policy 2010–2024 (NEP) is the diversification of the energy mix and the promotion of renewable energy resources. Since the implementation of the NEP, several adjustments have been made in the legal and regulatory frameworks of the electricity and environmental sectors as well as to taxation regulations to foster the development of renewable energy generation projects. The most significant adjustments include the following:

- The Law of Fiscal Incentives for the Promotion of Renewable Energy in Electricity Generation. The law establishes the type and duration of the fiscal benefits granted by the state to encourage the construction of new renewable energy power plants.
- The categorization of the environmental impact of activities, works or projects in the energy sector. Its purpose is to determine if a project requires an Environmental Impact Study (EIS) before its implementation.
- The Rules of Bidding Processes for Long-Term Contracts Supported with Renewable Distributed Generation establish the rules to follow in the implementation of this kind of public bidding processes.
- The Standard for End Users that Generate Electricity with Renewable Resources establishes the rules to follow by the end users for installing small power generation systems for self-consumption and the retribution model for sporadic energy injections in the distribution network.[13]

COST OF SMALL HYDROPOWER DEVELOPMENT

The Japan International Development Agency estimated the cost of SHP development in El Salvador in a 2012 Master Plan study for the development of RES in the country. The study proposed a three-phase programme for realizing the potential of the 123 identified SHP sites, with costs per phase ranging between 2,761 USD/kW and 3,391 USD/kW and with an overall average cost of 2,972 USD/kW.[14]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

El Salvador has taken significant steps at the regulatory and institutional level to promote the development of hydropower plants (and RES in general). Nevertheless, structural issues that may hinder development still persist, including the following:

- Lack of accurate hydrological data;
- Outdated estimates of SHP potential;
- The period to obtain a concessions permit is not clearly defined and induces uncertainty in the development process;
- Potential social opposition to SHP projects;
- The high investment costs of SHP in El Salvador compared to competing RES technologies;
- Few domestic options for financing SHP plants.

The key enablers of SHP development in the country are:

- Several detailed studies of SHP potential and inventories of potential SHP sites in the country have been conducted, although the collected data are not up-to-date;
- Significant unrealized SHP potential remains.

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Guatemala

Jonas Dobias, Water and Energy Independent Consultant

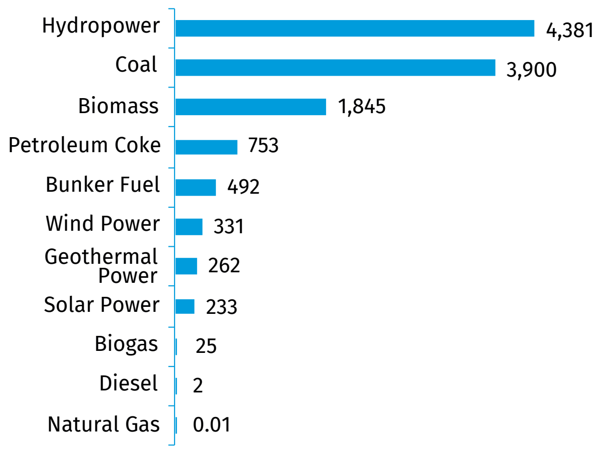
KEY FACTS

Population	16,850,000 (2020)[1]
Area	108,889 km[2] [2]
Topography	A tropical plain of approximately 48 kilometres in width parallels the Pacific Ocean. Guatemala also has a piedmont region, which rises to altitudes of 90–1,370 metres. Nearly two-thirds of the country lies above these regions, in a mountainous, volcanic area stretching from the north-west to the south-west. The highest peak is Tajumulco (4,211 metres). To the north of the volcanic belt lies the continental divide and, even further north, the Atlantic lowlands.[2]
Climate	Guatemala is divided into three climatic zones. Daytime temperatures can reach as high as 40 °C and temperatures at night rarely drop below 20 °C. At approximately 1,000–2,000 metres above sea level lies a zone with temperatures rarely exceeding 30 °C. Daytime temperatures there are only slightly lower than in the temperate zone; however, the nights are rather cold and temperatures can drop below freezing.[2]
Climate Change	Due to climate change, the temperatures are projected to increase by 2.1–4.5 °C by 2050 and by 3.3–5.4 °C by 2070. Precipitation is expected to decrease by 9.5–12.4 per cent and 18.4–28.9 per cent for the same periods.[3]
Rain Pattern	Precipitation varies across the dry (May to October) and wet (November to April) seasons. The average annual rainfall in Guatemala for the period 2001–2016 was approximately 1,967 mm.[4]
Hydrology	In terms of hydrology, the country can be divided into three main areas. The Pacific Rim comprises 18 river basins. The coast on the Caribbean Sea, which includes the most important river, the Motagua, comprises 10 basins. There are also 10 basins in the Gulf of Mexico region, home to the most abundant rivers in the country.[2]

ELECTRICITY SECTOR OVERVIEW

In 2019, total electricity generation in Guatemala was 12,224 GWh, of which 2,102 GWh were exported, mainly to the Regional Energy Market (MER), formed by Guatemala, El Salvador, Honduras, Nicaragua, Costa Rica and Panama. A small portion was exported to Mexico. At the same time, 1,068 GWh were imported from the MER and Mexico. Hydropower accounted for 4,381 GWh of total domestic generation, followed by 3,900 GWh from coal, 1,845 GWh from biomass, 753 GWh from petroleum coke, 492 GWh from bunker fuel, 262 GWh from geothermal power, 331 GWh from wind power, 233 GWh from solar power, 25 GWh from biogas, 1.66 GWh from diesel and 0.01 GWh from natural gas. Hydropower was the main source, accounting for approximately 36 per cent of the generation in 2019 (Figure 1).[6]

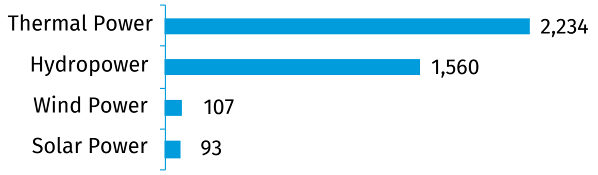
Figure 1. **Annual Electricity Generation by Source in Guatemala in 2019 (GWh)**



Source: AMM[6]

In 2019, the total installed capacity of Guatemala was 3,993 MW and available capacity stood at 3,415 MW. Of the total installed capacity, combustion (coal, diesel, bunker fuel and biomass) accounted for 56 per cent, hydropower for 39 per cent, wind power for 3 per cent from and solar power for 2 per cent (Figure 2).[6]

Figure 2. **Installed Electricity Capacity by Source in Guatemala in 2019 (MW)**



Source: AMM[6]

The total electrification rate in the country in 2019 was above 92 per cent.[6] However, there is a big gap between the more urban departments and the departments with high rural population. Guatemala is divided into 22 regions and each region, in its turn, is divided into municipalities, with a total of 340 municipalities in the country. Fourteen regions have an electricity network coverage of above 95 per cent; four of approximately 90 per cent; two of between 80 per cent and 85 per cent; one of approximately 68 per cent and one of 44 per cent.[7] The lowest electrification rate is recorded in the northern area, where the lowest economic indicators are shown.

Since 1998, the electricity sector in Guatemala works as an open market, where the Wholesale Market Administrator (AMM) has two products for transactions: electric power (MW) and electricity (MWh). There are two procedures for these transactions. The first one is based on prices fixed in mid- and long-term contracts; this is where most of the transactions are completed. The second one is executed through the AMM, where the transactions are based on costs set by the Regulation of the Wholesale Market Administrator (RAMM) rather than on market prices.[5] Electricity generating companies set their own electricity costs and the AMM calls them for dispatching in an order from the lowest to the highest cost on the spot market.

The electricity sector in Guatemala is unbundled, involving both state and private players, known as electricity market agents, who are active in the generation, transmission, trading and distribution segments. The electricity sector planning in Guatemala is overseen by the Ministry of Energy and Mines (MEM), while the National Electricity Commission (CNEE) is in charge of regulation. Energy dispatching is operated by the non-governmental organization AMM.

The state-owned company INDE owns 14 per cent of the total installed capacity, mainly hydropower, while the other 86 per cent is owned by the private sector. In total, there are eight transmission companies. The largest one is operated and owned by INDE (over 75 per cent of the total), while the other seven are privately-owned, of which one owns the regional line of SIEPAC. There are 19 distribution companies. One belongs to INDE and provides services to 42 per cent of users, two private companies provide services to 51 per cent of users and 16 municipal companies provide services to the remaining 7 per cent of users.[8]

The electricity tariffs in Guatemala are set by the CNEE every five years. These are adjusted every three months based on the electricity bought by the distributor, cost of electricity transmission and the distribution taxes (Table 1). In general, the price of electricity depends on the exchange rate the US dollar, international fuel prices and current hydrological conditions. Households that consume less than 300 kWh per month receive a subsidy from the state through INDE. A street light service cost is added to every user according to the municipality tariffs.

Table 1. **Electricity tariffs in Guatemala, May–July 2020**

Company	*Social tariff (USD/kWh)*	*Regular tariff (USD/kWh)*
DEOCSA	0.23	0.25
DEORSA	0.22	0.23
EEGSA	0.16	0.17

Source: CNEE[9]

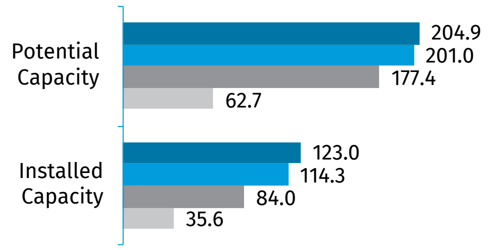
The Government plans to develop the electricity sector are enclosed in the following documents:

- The National Energy Plan 2017–2032, which is based on three axes: (i) sustainable use of natural resources; (ii) energy efficiency; and (iii) greenhouse gas emissions reduction.
- The Expansion Plan for the Generation and Transportation System 2018–2032, which, according to the RAMM Article 15, should cover a period of 10 years and be updated every 2 years.
- The Energy Policy 2019–2050, which is based on five axes: (i) electricity supply and use; (ii) fuel supply and use; (iii) energy efficiency; (iv) firewood use; and (v) sustainable development.
- The Expansion Plan for the Generation System 2020–2050, whose objectives are: (i) promotion of investments in electricity generation from renewable sources; (ii) promotion of natural gas, solar and wind power; (iii) focus on a strategic power system resilient to climate change; (iv) promotion of generation systems in areas where they do not currently exist; (v) integration of new energy sources into the transmission system. This plan also sets the objective to install approximately 60 power plants, from which seven are small hydropower (SHP) plants. The plan has also set three scenarios of annual electricity demand for 2050: low at 18,940 GWh, medium at 25,345 GWh and high at 42,510 GWh.
- The Rural Electrification Plan 2020–2050, which sets seven indicators for the selection of potential areas for rural electrification, the majority of which are off-grid. The plan also states an estimated investment cost for the implementation in each area.[10,11,12,13,14]

SMALL HYDROPOWER SECTOR OVERVIEW

In Guatemala, the definition of SHP refers to plants that have an installed capacity below 5 MW. In total, there are 74 SHP plants registered as a distributed renewable generator with MEM. Sixty-five plants are currently operating (123 MW), 33 are registered but are not operating (80 MW) and one is pending registration (1.9 MW). In comparison to the World Small Hydropower Development Report (WSHPDR) 2019, four new SHP plants have been commissioned with a combined capacity of 5.1 MW (Figure 3, Table 2). These started operating by the end of 2018 and the beginning of 2019.[14]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Guatemala (MW)**



Source: WSHPDR 2016,[2] MEM,[15] WSHPDR 2013,[16] WSHPDR 2019[17]

Note: Data are for SHP up to 5 MW.

There is currently no accurate estimate of the SHP potential capacity in Guatemala. During the 1970s and 1980s, a Master Hydropower Plan for the country was developed, which estimated hydropower capacity at approximately 5,000–6,000 MW.[18] However, this capacity is only theoretical. Based on the combined capacities of operating, registered and pending-registration SHP plants, it can be assumed that there is at least 204.9 MW of SHP potential.

Most SHP projects in Guatemala are developed privately or through development assistance from international donors. The list of planned SHP projects to be connected to the national grid is shown in Table 3.

Table 2. **List of Selected Operational Small Hydropower Plants in Guatemala**

Name	*Location (department)*	*Installed capacity (MW)*	*Launch year*
La Mejana	San Marcos	1.00	2019
Hidrosan I	Chimaltenango	2.00	2018
Hidroxocobil	Retalhuleu	1.40	2018
Choliva	Chimaltenango	0.74	2018
Cutzan	Suchitepequez	1.95	2017

Source: AMM[19]

Table 3. **List of Selected Planned Small Hydropower Projects in Guatemala**

Name	*Location (department)*	*Capacity (MW)*
Pacayas	Alta Verapaz	5.00
CHT	Suchitepequez	4.50
Maxanal	Suchitepequez	2.80
San Luis	El Quiché	2.10
San Francisco	Quetzaltenango	0.40

Source: AMM[19]

There are micro-hydropower plants (below 1 MW) not connected to the national grid, which are generally located in remote rural areas and are directly operated by small local communities. Normally, these micro-hydropower plants have been funded by international cooperation programmes, which own their distribution grids that are not connected to the national grid. In addition, some municipalities have their own plants. Most, if not all, of them are old and out of service due to lack of maintenance. In some cases, they are damaged due to natural catastrophes, such as floods, resulting from hydrological extreme events. Although there are no concrete plans, some of these already have a prefeasibility study.

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

There is no official list of selected SHP sites available for development. However, the author of this chapter, as a technical adviser and hydrologist for MEM and CNEE, was responsible for the technical evaluation of three municipal hydropower plants that are currently out of service (Table 4).

Table 4. **List of Selected Small Hydropower Projects Available for Development in Guatemala**

Name	*Location (department)*	*Potential capacity (MW)*	*Type of site*
La Castalia	San Marcos	2.0	Reconstruction
Panzos	Izabal	0.5	Reconstruction
Polinsipec	Alta Verapaz	0.4	Reconstruction

Source: Dobias[20]

RENEWABLE ENERGY POLICY

The sustainable use of renewable energy resources is included in the first axis of the National Energy Plan for 2017–2032, the Guatemalan Climate Change Framework Law and the National Policy on Climate Change.[10,21,22] Furthermore, the promotion of investment into renewable energy technologies and of a strategic power system resilient to climate change are specific objectives included in the Expansion Plan for the Generation System 2020–2050.[13] The Plan also includes the construction of 60 hydropower plants, of which 6 are SHP plants. The aforementioned plans also align with international agreements, such as the United Nation Framework Convention on Climate Change (UNFCCC), the Paris Agreement and the Nationally Determined Contributions (NDCs). Concerning the latter, Guatemala has committed to an 11.2 per cent reduction of its carbon emissions by 2030 (or 22.6 per cent provided it can count on the technical and economic assistance from international donors). This reduction is focused on five sectors for mitigation actions, including the energy and transport sectors.[23]

Furthermore, the Rural Electrification Plan 2020–2050 has set the objective of reaching a 93.5 per cent electrification rate by 2023. The plan also describes the potential use of micro-hydropower plants (5–100 kW) and micro-grids in remote areas.[14]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

There are no specific government plans or programmes targeting SHP. However, the National Energy Plan 2020–2050 and the Expansion Plan for the Generation System 2020–2050 call for the implementation of small and micro-hydropower plants of up to 5 MW and 1 MW of capacity, respectively. Furthermore, the Technical Norm for Generation of Renewable Energy and Self-Producers with Energy Excess (NTGDR) is another example of regulations focusing on small-scale renewable energy plants (up to 5 MW). The NTGDR describes that SHP and other renewable energy plants can sell their electricity to the national electricity market or sell directly to the distribution companies.[24]

The development of hydropower below 5 MW does not make use of the national grid. Therefore, such projects do not require an authorization from MEM. However, they must be registered with MEM, as established in Article 8 of the General Electricity Law.[25] Such projects must be completed with several requirements, such as an Environmental Impact Assessment or an Environmental Flow Design from the Ministry of Environment and Natural Resources (MARN) to obtain the Environmental Licence. They also have to fulfil other requirements from different institutions, including the localization and forestry management documentation from the National Committee for Protected Areas (CONAP) and the National Institute for Forestry (INAB), respectively, as well as connection authorizations or studies from CNEE, AMM and INDE.

Overall, SHP development in the country is facilitated by a developed system of institutions responsible for registering, granting licences and conducting connection studies for SHP development projects are:

- MEM, responsible for the registration of SHP projects, national and official publication of renewable energy regulations, including tax incentives for renewable energy projects. MEM is currently developing a model for hydropower development, which requires developers to comply and align with the International Labour Organization (ILO)'s "C169, Indigenous and Tribal Peoples Convention";
- CNEE, responsible for the authorization of connection to the main electric grid;
- AMM, responsible for the required study to be incorporated in the energy wholesale market;
- INAB, responsible for the certification for forestry management;
- CONAP, responsible for the certification stating that the project is not developed in a protected area;
- MARN, responsible for environmental impact assessments.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

INDE is one of the biggest financial sources for the implementation of rural electrification projects. At the moment of writing of this chapter, INDE was evaluating the possibility to receive a loan of USD 100 million from the Inter-American Development Bank (IDB) to finance and execute the Rural Electrification Plan 2020–2050.[14] Another mechanism aimed to promote the development of renewable energy in the country is the Law on Incentives for Renewable Energy Development, which exempts equipment and machinery used for renewable energy projects from custom tariffs. The law also provides tax exemptions during the first 10 years of operation of such projects.[26]

In previous years, the programme called Green Micro, Small and Medium Enterprises (MIPYMES Verde) used to be the main financial mechanism for the development of SHP in the country. The programme concluded in 2017. However, a second phase is planned to promote the development of renewable energy projects (solar power, hydropower, wind power, biomass and biogas) under 5 MW of installed capacity, for which a reimbursable fund of approximately USD 40 million is available. Nevertheless, as of 2021, due to the COVID-19, the status of the programme remained uncertain.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Currently, Guatemala has not established any climate change adaptation measures for SHP plants in its regulation. However, projects may establish their own adaptation measures.

During a workshop on climate change and its effects on hydropower generation organized by CNEE in 2014, four national experts on hydrology for hydropower were invited to discuss the threats that climate change presents to hydropower development. They also discussed the potential options to minimize the negative impacts. One of the conclusions was that, considering the expected increases in temperatures and decreases in precipitation, the estimated potential of hydropower in the country (5,000–6,000 MW) may be lower in the near future. Furthermore, it was also concluded that an increase in the density of the grid of hydrological and climatic gauges in the country is needed.[18]

Furthermore, the IDB and the Latin American Organization for Energy (OLADE) developed a study called "Vulnerability of the Hydropower System due to Climate Change in Central America and Adaption Options". The study analyzed one main hydropower plant in each country and concluded that, despite climate change being a menace in the region, hydropower will still be a viable option for energy supply in the region. However, it recommended that new projects should consider the variability of the climate in the short, mid and long term.[27]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Some barriers to the development of SHP and hydropower in general in Guatemala are:

- Environmental and social opposition to the development of hydropower. For this reason, the MEM has developed a methodology for consulting local populations based on the ILO Convention C169;
- In some cases, the hydropower potential is located far from the main grid (distribution or transmission lines) and connection lines turn out to be very expensive relative to the whole hydropower project;
- Economic and financial limitations, particularly for off-grid hydropower in rural communities, where international cooperation and assistance is the main funding source.[28]

The key enablers for further SHP development in the country include:

- A developed system of institutions responsible for registering, granting licences and conducting connection studies for SHP projects;
- Available undeveloped potential;
- Government policy conducive to renewable energy development.

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Honduras

Laura Stamm, International Center on Small Hydro Power (ICSHP)

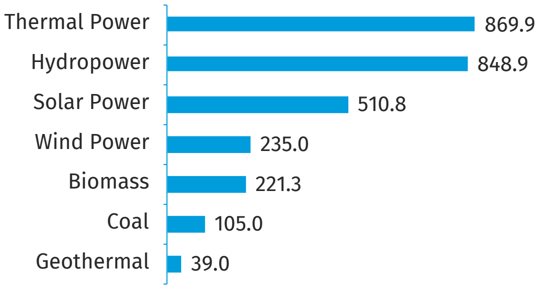
KEY FACTS

Population	9,904,608 (2020)[1]
Area	112,491 km^2 [2]
Topography	The Central American Cordillera Mountain Range sweeps the country east to west so that more than 75 per cent of the country's surface area is mountainous. The highest altitudes are found in the western region, where the country's highest point, Cerro Las Minas at 2,870 metres, is situated. The Volcanic Highlands are to the south-west. Very narrow plains can be found along the southern coast of the Gulf of Fonseca that opens to the Pacific Ocean. The northern coast with the Caribbean Sea has slightly wider plains, particularly in the north-eastern lowland region known as La Mosquitia.[3,4]
Climate	The climate in Honduras is temperate in the interior mountain areas and tropical near the coasts. Average temperatures in the highlands are between 19 °C and 23 °C with the highest areas being cooler, at approximately 14°C. Average temperatures in the coastal lowlands are between 26 °C and 28 °C, but are usually higher between May and November. The Caribbean coast remains hot and humid throughout the whole year, but the Pacific coast has a dry period between December and April when temperatures can be slightly cooler.[3]
Climate Change	In the past 50 years, average temperatures in Honduras have increased by approximately 0.4 °C and extreme weather events have also considerably increased. In 2015, German Watch's climate risk index classified Honduras as the country most affected by extreme weather events caused by climate change during the 1994–2013 period. These trends are expected to continue, specifically regarding the prevalence of hurricanes experienced by the country. Average temperatures are expected to rise by between 2.1 °C and 4.6 °C by the end of the century, with the interior highland region being most susceptible to the highest increase. A decrease in average rainfall is also anticipated.[5]
Rain Pattern	The rainy season throughout the country is generally from May to November. The northern coastal region experiences the most rainfall, between 1,800 mm and 2,800 mm annually. While rainfall happens all year long in this area, the heaviest rainfall and occasional hurricanes happen between June and November. Average rainfall in the southern coastal region is between 1,500 mm and 2,000 mm per year, almost all of which happens between May and November. Average rainfall in the interior mountain regions is between 1,000 mm and 1,800 mm annually.[3]
Hydrology	Honduras is a water-rich country. The majority of the waterways flow from the interior mountains to the north, emptying into the Caribbean. There are 14 significant rivers that produce approximately 82 per cent of the country's runoff that follows this path. The most important rivers that flow northwards are the Ulúa, Patuca and Aguán. These rivers often flood for a portion of the year and are at their lowest points between March and May. In the south, there are five rivers that flow from the interior and empty into the Pacific, and the Goascorán River is the most important of them. The rivers Lempa and Coco are considered border rivers, forming the borders with El Salvador and Nicaragua, respectively. The largest lake in the country is Lake Yojoa with an area of approximately 90 km^2, located within the western highlands.[6]

ELECTRICITY SECTOR OVERVIEW

At the end of 2021, total installed capacity in Honduras was approximately 2,830 MW, more than 65 per cent of which was renewable energy. Installed capacity of thermal power, mostly heavy fuel oil, was just under 870 MW (31 per cent). Hydropower accounted for approximately 849 MW (30 per cent), solar power for slightly less than 511 MW (18 per cent), wind power for 235 MW (8 per cent), biomass for just above 221 MW (8 per cent), coal for 105 MW (4 per cent) and geothermal power for 39 MW (1 per cent) (Figure 1).[7] There are three state-owned thermal power plants which comprise a combined 30 MW of installed capacity and six state-owned hydropower plants amounting to 537 MW. The remaining 2,263 MW of installed capacity is dispersed between numerous privately-owned plants. The largest single power plant is the state-owned Francisco Morazán hydropower plant with 300 MW of installed capacity.[7]

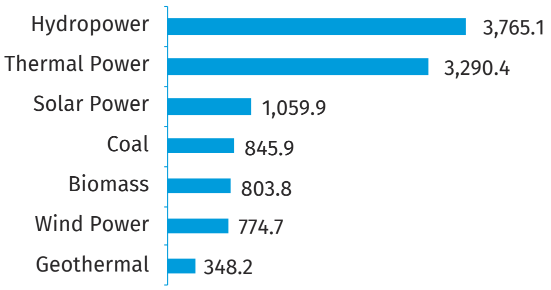
Figure 1. **Electricity Installed Capacity by Source in Honduras in 2021 (MW)**



Source: ENEE[7]

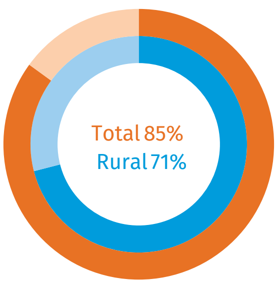
The total electricity generated in Honduras in 2021 was 10,888 GWh. Hydropower accounted for 3,765 GWh (35 per cent), thermal power generated 3,290 GWh (30 per cent), solar power 1,060 GWh (10 per cent), coal 846 GWh (8 per cent), biomass 804 GWh (7 per cent), wind power 775 GWh (7 per cent) and geothermal power 348 (3 per cent) (Figure 2). An additional 204 GWh was imported, most of which came from Guatemala.[7]

Figure 2. **Annual Electricity Generation by Source in Honduras in 2021 (GWh)**



Source: ENEE[7]

Figure 3. **Electrification Rate in Honduras in 2019 (%)**



Source: Government of Honduras[8]

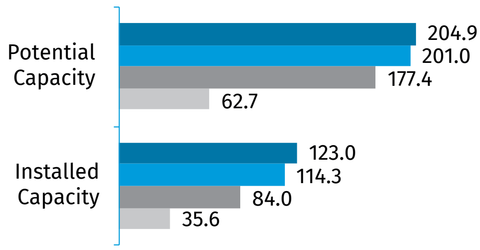
There is a considerable number of isolated rural communities throughout Honduras, particularly in the east, and many lack infrastructure connecting them to the more populous and urban epicentres in the west. This results in a contrast of electrification rates throughout the country. The overall electrification rate in 2019 was 85 per cent, with a 95 per cent urban electrification rate and 71 per cent in rural areas (Figure 3). Connection varies greatly throughout the rural areas, as the department of Gracias a Dios in the far north-eastern Mosquitia region has the lowest electrification rate of the country with less than 8 per cent.The state-owned National Company of Electrical Energy (ENEE) was originally created in 1957 in order to assume full responsibility of all the generation, distribution and transmission of electricity in the country. However, in the early 1990s, electricity demand grew at a faster rate than the ENEE could supply, which resulted in the passing of the Electricity Subsector Framework Law of 1994 which opened the sector for private companies to sell energy to ENEE. The law also created the National Commission of Electric Energy (CNEE) to oversee the contracts between ENEE and private companies. In 2014 full liberalization of the electricity sector emerged with the General Law of the Electric Industry, with the goal to improve efficiency through decentralization. Subsequently, the Regulatory Commission for Electric Energy (CREE) was established as a regulatory authority in the newly liberalized market. The Ministry of Natural Resources and the Environment (SERNA) grants environmental licences and oversees the sector as a whole.[8]

Electricity tariffs are set by CREE based on such factors as currency fluctuation, fuel prices and the state of the generation, transmission and distribution subsectors. Tariffs vary according to the type of consumer and usage and in January of 2022 prices per kWh ranged from USD 0.16 to USD 0.25.[9]

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) is defined in Honduras as hydropower plants with a capacity of up to 30 MW. In December of 2021, there were 45 SHP plants up to 30 MW with a combined installed capacity of 288.6 MW. Of these SHP plants, 37 had a capacity of up to 10 MW with a combined capacity of approximately 148 MW.[3] The total hydropower potential in Honduras is approximately 5,000 MW and the SHP potential up to 10 MW is estimated to be 385 MW (Table 1).[10] In comparison with data from the World Small Hydropower Development Report (WSHPDR) 2019, the installed capacity has increased by 20 MW, more than 15 per cent, due to the completion of new SHP plants, while the potential remained unchanged (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Honduras (MW)**



Sources: ENEE,[3] CIF,[10] WSHPDR 2013,[11] WSHPDR 2016,[12] WSHPDR 2019[13]

Note: Data for SHP up to 10 MW.

Table 1. **List of Selected Operational Small Hydropower Plants in Honduras**

Name	*Location*	*Installed capacity (MW)*
Sazagua Puringla	La Paz	10.0
Aurora	La Paz	9.0
Río Bertulia	Colón	8.3
Cuyagual	Santa Barbara	7.0
Chachaguala	Cortés	6.8
Nispero	Santa Barbara	6.0
Genera	Atlántida	5.2
Río Frio	Ocotepeque	3.9
Río Zingiuzapa	Francisco Morazan	3.1
Churune	Comayagua	3.0
Canjel	Santa Barbara	3.0
San Martín	Olancho	3.0
Corral de Piedras	Olancho	2.8
San Alejo	Atlántida	2.2
Coyolar	Comayagua	1.8
Matarras	Atlántida	1.7
Guineo	Olancho	1.4
Quilio	N/A	1.1
Agua Verde	Cortés	1.0
Peña Blanca	Cortés	0.9

Source: ENEE,[3] Bertrand & Álvarez[14]

Note: Data for SHP up to 10 MW.

RENEWABLE ENERGY POLICY

The first legislation that was passed with the goal to reduce the country's dependence on fossil fuels was the Law for Renewable Energy of 1998 under Decree No. 267-1998. This provided tax incentives for renewable energy generation up to 50 MW and obligated state company ENEE to purchase renewable energy at a maximum price. Tax incentives include exemption of import and sales tax and a five-year income tax exemption.[8,15] To further push for an increase in renewable energy, the Law on the Promotion of Electric Power Generation with Renewable Resources was passed in 2007. This augmented the incentives from the 1998 decree and included preferential tax and sales policies. It granted income and import taxes and dispatch priority of renewable energy on the grid.[13,16] Additional decrees in 2011 and 2013 further expanded on incentives for renewable energy. In particular, they:

- Created a registry of small renewable energy producers;
- Set transmission charges of 0.01 USD/kWh for renewable energy projects;
- Extended the incentives for renewable energy projects, such as exoneration of income tax, import duties and concession fees (except for hydropower) and tax credits on pre-investment expenditures;
- Extended the incentives to off-grid projects for distributed generation;
- Established net-metering for users under 250 kW;
- Established a special incentive for solar photovoltaics (PV) projects that had started operations before August 2015, fixing the duration of the 10 per cent incentive at 15 years and adding an extra premium of 0.03 USD/kWh. Limited to projects under 50 MW and not exceeding 300 MW of total installed capacity;
- Exonerated all renewable energy projects that provide an Environmental Impact Assessment (EIA) from construction permit fees.[13]

These initiatives are aimed at facilitating the transition of the energy mix in compliance with the provisions of the Country Vision and National Plan Law constituted into State Policy by Decree No. 286-2009. This law stated the goal to reach an energy mix composed of 60 per cent renewable energy by 2022 and 80 per cent renewable energy by 2038.[17] The goal to reach 60 per cent renewable energy has since been reached.

Rural electrification using renewable energy is a priority in Honduras. In 2012, the Honduras Scaling-Up Renewable Energy Programme in Low-Income Countries (SREP) was approved by the Inter-American Development Bank (IADB). This secured more than USD 30 million in grants and near-zero interest for a diverse programme of investment plans aimed at creating a more conducive environment for the renewable energy sector. Specific activities financed under the SREP include: a grid-connected renewable energy programme; a rural electrification strategy to accelerate electricity access in remote areas; promoting access to improved and appropriate cooking technologies; and a policy and regulatory reform initiative intended to improve the conditions for development of the country's renewable energy sector.[18] The SREP is an ongoing fund and as of 2021 was still accepting project requests. Recent activity includes a 2020 approval of the construction of 20 solar-powered mobile health units and an international bidding held in May of 2021 to supply goods and related services to constructing a mini-grid in isolated regions, including the least electrified department of the country.[19,20]

LEGISLATION ON SMALL HYDROPOWER

To develop SHP in Honduras, special licensing and permits granted by SERNA are required based on the size of the project, separated into three categories. For category 1 projects, between 0.5 MW and 1 MW, a Certificate of Environmental Registry must be obtained but has minimal requirements. Category 2 projects, between 1 MW and 3 MW, require an Environmental Authorization licence which calls for a qualitative environmental assessment amongst other requirements. Category 3 projects, above 3 MW, require an Environmental Licence and an EIA to be carried out at the site. For all projects, an additional contract of water is required.[21]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Some key barriers hindering the development of SHP in Honduras include:

- The equity capacity by private investors in Honduras is concentrated in larger, fossil fuel-based energy projects;
- The lack of road infrastructure and ancillary services markets;
- The need to invest in a transmission network.[13]

Some enablers that could encourage SHP development in the country:

- Full market liberalization allows for new entries into the market;
- Most of the total hydropower potential has not yet been utilized, leaving much opportunity;
- The low rural electrification rate in the country exhibits a need for more power plant developments, particularly in the eastern region of the country.

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Mexico

Sergio Armando Trelles Jasso, Mexican Institute of Water Technology (IMTA)

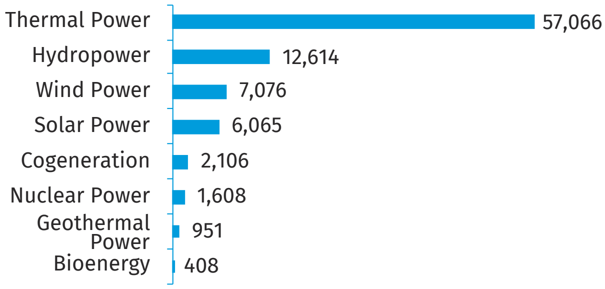
KEY FACTS

Population	126,014,024 (2020)[1]
Area	1,965,262 km^2 [2]
Topography	The relief of Mexico is characterized by several mountainous chains, including the Peninsula of Baja California (1,200 km long), Western Sierra Madre (1,400 km), Eastern Sierra Madre (600 km), Southern Sierra Madre (1,000 km), Sierra Madre of Oaxaca (300 km), Central American Mountain Range (with a peak altitude of 4,092 metres) and Neovolcanic Axis (with a peak altitude of 5,610 metres). The altitude of the Central High Plateau ranges from 500 metres to 2,600 metres. From these formations the altitude descends to the Northern Plateaus, the Sonora and Chihuahua Deserts and the coastal plains along the Pacific Ocean and the Gulf of Mexico. The Peninsula of Yucatan in the far south-east is a flat karst formation with almost no streams or rivers.[3]
Climate	The average temperatures range from 16 °C in the states of Tlaxcala and Mexico to 27 °C in the Peninsula of Yucatan.[4] The minimum temperatures, below -6 °C, occur in December and January in the northern mountainous areas. The maximum temperatures, above 48 °C, have occurred between April and July in the north-west, along the Pacific coast and the central parts of the country. There is a great diversity of climate: dry in most of the centre and north (28 per cent of the country); very dry in the north-west (21 per cent); warm and humid in the south (5 per cent); warm subhumid along the coasts (23 per cent); temperate humid in the mountains of the south (3 per cent) and temperate subhumid in the mountains near the coasts (21 per cent).[5]
Climate Change	Mexico is highly vulnerable to the effects of climate change, which impacts both human populations and ecosystems. It is expected that cyclones will be more intense in the north-west, as well as along the Pacific and Atlantic coasts. Strong storms are likely to become more frequent, increasing the risk of flooding. At the same time, most of the country is projected to become drier and drought frequency is also likely to increase, with a consequent increase in the demand for water.[6]
Rain Pattern	From 1981 to 2010, the average annual precipitation in the country was 740 mm. The spatial distribution varies greatly, from 98 mm in the Río Colorado to 2,220 mm in the Coast of Chiapas. Annual precipitation extremes range from 33 mm in the north-west to above 4,500 mm in the south-east.[7] The rainy season, from May to October, accumulates 83 per cent of the annual rainfall. Every year, between July and October, there are tropical storms and hurricanes that reach both littorals. From 1970 to 2015, there were 224 such events, most of them on the Pacific coast, but the strongest ones occurred on the Atlantic coast.[8,9]
Hydrology	The country is divided into 37 hydrologic regions, which are further divided into 158 river basins and 976 subbasins.[10] The total mean runoff is estimated at 354,990 hm^3 per year, equivalent to 180 mm per year across the entire country or approximately 21 per cent of the annual rainfall. Two thirds of the total runoff occur in seven river basins that cover 22 per cent of the surface of the country: Grijalva-Usumacinta, Papaloapan, Coatzacoalcos, Balsas, Pánuco, Santiago and Tonalá.[9]

ELECTRICITY SECTOR OVERVIEW

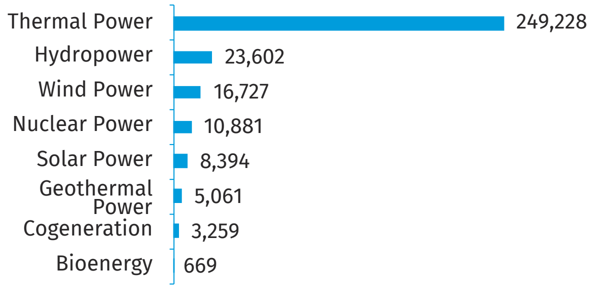
The total installed capacity of Mexico in 2020 was 87,894 MW, indicating a 12 per cent increase since 2019. Of this total, thermal power from fossil fuel sources contributed 57,066 MW (65 per cent), hydropower contributed 12,614 MW (14 per cent), wind power contributed 7,076 MW (8 per cent), solar power contributed 6,065 MW (7 per cent), efficient cogeneration contributed 2,106 MW (2 per cent), nuclear power contributed 1,608 MW (2 per cent), geothermal power contributed 951 MW (1 per cent) and bioenergy contributed 408 MW (less than 1 per cent) (Figure 1). Relative to 2019, there has been a marked increase in all forms of clean renewable energy, particularly solar power capacity, which increased by over 66 per cent. Conversely, hydropower installed capacity remained stable. The largest generating capacities are located in the states of Chiapas, Veracruz and Guerrero, while states with the smallest installed capacity include Morelos, Campeche and Mexico City.[11]

Figure 1. **Installed Electricity Capacity by Source in Mexico in 2020 (MW)**



Source: SENER[11]

Figure 2. **Annual Electricity Generation by Source in Mexico in 2019 (GWh)**



Source: SENER[11]

There are four types of entities in Mexico that produce electricity and contribute to the total installed capacity. The state-owned Federal Electricity Commission (CFE) owns a 51 per cent share of the installed capacity, operating a variety of technologies including the country's only nuclear power plant. Independent power producers that sell all their production to CFE own 19 per cent of total capacity, primarily operating combined-cycle plants and some wind power plants. Private producers that are authorized to sell electricity on the open market own 28 per cent, operating combined-cycle plants and a variety of plants based on renewable energy sources (RES). Finally, the state-owned oil company PEMEX owns approximately 1 per cent of the total capacity, operating plants based on efficient cogeneration, conventional thermal power and gas turbine technologies.[11]

The total annual electricity generation in 2019 was 317,820 GWh, with thermal power providing 249,228 GWh (over 78 per cent) of this total, hydropower providing 23,602 GWh (7 per cent), wind power providing 16,727 GWh (5 per cent), nuclear power providing 10,881 GWh (3 per cent), solar power providing 8,394 GWh (nearly 3 per cent), geothermal power providing 5,061 GWh (nearly 2 per cent), efficient cogeneration providing 3,259 GWh (1 per cent) and bioenergy providing 669 GWh (less than 1 per cent) (Figure 2). The combined share of electricity generated from clean renewable and clean non-renewable sources was nearly 22 per cent of total generation.[11] It is also notable that nearly 59 per cent of electricity generated in 2019 was provided by combined-cycle and gas turbine plants, which import 90 per cent of the gas used for generation from the United States of America (USA).[12]

The National Electric System (SEN) is organized in nine regions, each with a control centre. Seven of the regions cover most of the territory of the country with dense electric transmission and distribution networks that constitute the National Interconnected System (SIN). The remaining two regions are on the peninsula of Baja California that has three regional networks: one on the north (BCN), linked to an electrical network in the USA; another in the south of the state (BCS); and the isolated network of Mulegé (MUL).

The electricity grid infrastructure comprises the National Transmission Network (RNT), which has 55,816 kilometres of high voltage transmission lines (230–400 kV), continued by 54,497 kilometres of high voltage subtransmission lines (69–161 kV) and the General Distribution Networks (RGD), which have 872,946 kilometres of medium- and low-voltage distribution lines (from 33 to less than 2.4 kV). As of 2021, the RNT possessed a transformation capacity of 165,713 MVA, while the transformation capacity of the RGD was 77,978 MVA.[11] The technical and non-technical losses in the SEN are estimated at 12 per cent. There is a programme in execution to control losses. The expectation is to limit the losses to 8 per cent in 2034, following the international standard.[13] There are ongoing projects across Mexico to expand the RNT and RGD to meet increasing electricity demand, improve reliability, reduce costs, and fulfill clean energy goals.

On the northern border, Mexico has 11 interconnections with the states of Texas and California in the USA, with capacities ranging from 36 MW to 800 MW. On the southern border, a transmission line of 103 kilometres at 400 kV linking Mexico and Guatemala started operation in 2010.[14] There are plans to connect this strategic link to the Central American Electrical Interconnection System (SIEPAC), traversing 1,800 kilometres at 230 kV with a capacity of 600 MW and serving six countries of the Regional Electricity Market of Central America.[15] In addition, Mexico has been connected to Belize since 1998 by a transmission line of 115 kV and 230 kV with a capacity of 65 MW, which supplies approximately 70 per cent of the demand in Belize.

To connect a new power plant with capacity equal to or greater than 0.5 MW to the grid, it is necessary for the National Centre of Energy Control (CENACE) to execute one or more technical studies to ensure the reliability of the electric system. These include an Indicative study, an Impact on the System study, as well as an expedited Installations Study and Impact Study. The cost and the duration of the studies vary depending on the capacity of the plant. For example, for a small hydropower (SHP) plant of up to 30 MW, the set of studies can cost approximately USD 49,000 USD and require up to 55 working days.[16]

CFE has plans to build, acquire or participate in the development of power generation plants in order to maintain its leadership in the sector and ensure a 54 per cent share of national electricity generation by 2027 is to be met through the addition of 13 thermal projects, with an estimated investment of approximately USD 10 billion.[13]

The national electrification rate in the first quarter of 2021 was nearly 100 per cent, although a small degree of variation in electricity access exists throughout the country, with Mexico City having the highest rate of access at over 99.9 per cent.[17] Due to the operating reserve margin, shortages of electricity on a regional or seasonal scale normally do not occur. Some outages of electric supply of short duration and limited extent may occur, caused mainly by strong winds or heavy rain events.[18] However, in the last decade there have been several outages caused by major natural disasters, accidents and the strong dependence on gas imports from the USA for electricity generation. The most significant outage occurred on 15 February 2021, caused by the disruptions to gas supply infrastructure in Texas, USA as a result of extreme weather. Notably, on that occasion power was restored in Mexico much earlier than in Texas because of the rapid increase in generation by hydropower plants located in the south-eastern part of Mexico.

Electricity consumption in Mexico is highest in August and lowest in February. The overwhelming majority of electricity (nearly 95 per cent) is consumed by users connected to the SIN, mainly in the Central, Western and North-eastern regions. The remainder is accounted for by the two regional networks, BCN and BCS, in Baja California. The final consumption by end users in 2019 equalled 274,917 GWh. Medium industry accounted for 38 per cent of this total, large industry for 25 per cent, residential users for nearly 25 per cent, commercial users for 6 per cent, agriculture for nearly 5 per cent and services for nearly 2 per cent. The maximum demand of capacity in 2019 was 45,946 MW. The threshold of 95 per cent of maximum demand was exceeded in 131 of the 8,760 hours of the year, while the load factor was 76 per cent.

The Secretariat of Energy (SENER) has analyzed three scenarios (high, planning and low) of the expected growth in the capacity demand and electricity consumption for the period 2020–2034. The national gross consumption in the SEN for 2034 under an assumption of 2.7 per cent yearly increase, is expected to reach 483,317 GWh, 49 per cent higher than in 2019. Similarly, final consumption is expected to grow at a yearly rate of 3.1 per cent. The maximum demand of coincident capacity in the SEN for 2034, assuming a 2.8 per cent annual increase, is expected to reach 73,790 MW, a 60 per cent increase relative to 2019.[11]

A process of radical reforms of the legal and institutional framework of the energy sector was initiated in 2013, focusing mainly on the oil and gas industry, but also targeting the electricity sector. As part of the reforms, Articles 25, 27 and 28 of the Constitution were amended, along with 12 national laws, while 9 new laws were adopted in 2014, with a subsequent adjustment or adoption of the corresponding bylaws.[19] Changes included the partial privatization of the electricity sector. Previously, the right to generate, transmit, transform, distribute and supply electric energy for public service was exclusive of CFE. Following the reforms, the Government remained responsible for the planning and control of the SEN as well as for the RNT and RGD, while private companies were allowed to participate in the generation and sale of electricity and associated products, with the exception of nuclear power and the supply of electricity to residential consumers. The roles of the main public institutions in the electricity sector were adjusted accordingly, including those of the SENER, CFE, Regulatory Commission of Energy (CRE), CENACE, Secretariat of Environment and Natural Resources (SEMARNAT), National Water Commission (Conagua) and National Commission for the Efficient Use of Energy (CONUEE).

CFE and PEMEX, the national oil and gas company, were redefined as state-owned productive enterprises, required to compete with private companies and additionally allowed to form public-private partnerships. CFE was divided into nine subsidiary enterprises and four affiliated enterprises. The generation capacity of CFE was split among six subsidiaries that compete with each other using a variety of energy sources, including one business unit for nuclear power.

The legislative approval of the 2013 Energy Reform was extremely controversial since its inception and revealed many conflicts of interest among the political forces promoting this reform. The administration of Andrés Manuel López Obrador, inaugurated in December 2018, declared its intention to review the Energy Reform of the 2013 with the aim of moderating the most detrimental effects, rather than enact a complete reversal. A Presidential proposal to amend the Reform on a constitutional level was rejected in a historic vote on 17 April 2022. However, earlier measures to mitigate some aspects of the Reform were adopted on 9 March 2021 as part of amendments to the Law of Electric Industry, and finally validated by the Supreme Court of Mexico on 7 April 2022.[20] These measures are intended to promote the CFE as the predominant actor in the electricity sector and include the following:

- Modifications to electric dispatch criteria to prioritize hydropower and all CFE-owned plants over private plants of all other technologies;
- Obligation of all energy sector contracts to comply with the planning criteria defined by SENER;
- Issuance of Clean Energy Certificates (CEL) regardless of ownership and date of start of operation, to now include CFE's clean energy plants;
- Eliminating the obligation of CFE to buy energy for basic supply through auctions;
- Revocation of self-supply generation permits deemed to be fraudulent;
- Revision of existing Government contracts with independent power producers.[21]

The Wholesale Electricity Market (MEM) was launched in 2016 and is supervised by CENACE. The products sold on the

MEM include electric energy, capacity balance, CEL, ancillary services (SC) and financial transmission rights (DFT), among others. Within the MEM, participants have the option to conduct deals on five markets: the Short-Term Energy Market, composed of the Day-Ahead (MDA), the Real-Time (MTR) and the Hour-Ahead (Spot) markets; the annual Capacity Balance market; the CEL market, held at least annually; the periodic DFT market; and the medium- (3 years) and long-term (15–20 years) auctions of Energy, Capacity and CEL.

Interested parties, either legal entities or natural persons undertaking entrepreneurial activities, can register in the MEM as market participants under six modalities: Generator, Qualified User, Supplier of Basic Services, Supplier of Qualified Services, Supplier of Last Resort and Non-Supplier Marketer. The only supplier for residential consumers is CFE-Basic Supply. Private companies can be generators, suppliers and marketers of electricity directly to qualified users. Qualified users of energy, with demands of 1 MW or more, are able to buy from the MEM, from suppliers of qualified services or directly from generators. Private companies are allowed to participate in the expansion and operation of the transmission and distribution networks. Energy marketers and qualified users must buy a minimum percentage of capacity, either continuous or interruptible.

The MEM is an hourly cost market. The final price depends on the marginal cost of generation. The price is regulated by SENER, CENACE and CRE. The hourly Local Marginal Prices of electricity (PML) are calculated at 2,536 local price nodes of the SEN (NodoP), taking into account an energy factor, system losses and congestion of the substations. These prices are published online.[22]

CELs have been issued and traded since 2018. There have been three long-term auctions awarding 15-year contracts for the purchase of clean energy and CELs in 2016 and 2017, mainly to solar and wind power projects. The resulting average prices of electricity have decreased from 41.80 USD/MWh to 33.47 USD/MWh, and then further to a price of 20.57 USD/MWh. The decrease in prices has been associated with commercial competition and the reduction of costs of wind and solar power projects. A fourth auction was called in 2018, but later cancelled in 2019. The price scheme for the electric transmission service has been adjusted to reduce subsidies.[23]

An important amendment to the Law of the Electric Industry (LIE) promoted by the President entered into force on 10 February 2021. One of the amendment's main provisions changed the priority assigned by CENECE in dispatching the generation of power plants: first priority was assigned to hydropower plants; second, to the rest of CFE's power plants; third, to wind and solar power plants owned by private producers; last, to combined-cycle and other power plants owned by private producers. Additionally, CELs will be issued to all plants generating clean energy, including CFE's large hydropower plants. The amendment also stipulated that the Suppliers of Basic Services, including CFE, will no longer be obliged to buy products through energy auctions. Previously, the CFE had been buying electricity at auctions at prices higher than the electricity generated by its own plants, in a form of public subsidy for private producers. Finally, new technical feasibility criteria for intermittent energy sources were introduced for the connection to the grid and the legality and profitability with regard to the national budget of all permits and existing contracts relating to self-supply generators and IPPs will be reviewed and renegotiated or revoked.[24] However, this amendment precipitated strong opposition from private developers and the struggle concerning its application is ongoing.

As per Article 12 of the LIE, the CRE holds responsibility for setting the electricity tariffs in Mexico, in addition to other legal powers, including the granting and modification of generation permits, determination of rules of payment of production to distributed generators, issuance of grid and basic supply tariffs, issuance of rules and supervision of the MEM, authorization of model contracts for MEM and interconnection of power plants, granting of CELs, establishing the definition and criteria of clean energy, defining the rules for clean energy generation and for capacity acquisition, authorization of energy auctions, expression of opinion on the expansion of RNT and RGD, authorization of standards of interconnection of power plants, authorization of imports and exports of energy, record keeping of MEM participants, regulation and supervision of the standardization process and fostering the training of personnel for clean energy generation.[24]

The electricity tariff structure established by CFE takes into account the connection voltage level, the category of use, the region, the season, the required and used demand, the required continuity, the type of energy source, the day of the week and the level and hour of consumption (base, intermediate and peak). Consequently, more than 40 different tariffs are in place for different connections and usage characteristics. In general, the highest tariffs are those of the Baja California and Baja California Sur regions, while the lowest are applied in the North Central, North-eastern and North-western regions. The tariffs are charged in Mexican pesos (MXN) and are indexed on a monthly basis.

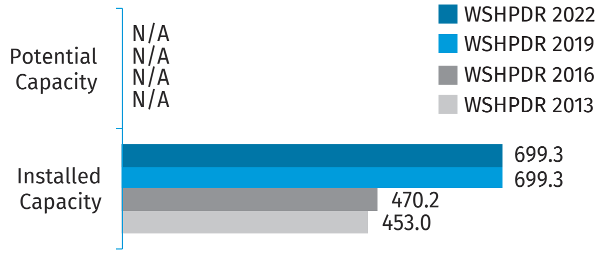
The transmission tariffs applicable to Qualified Users of the MEM for 2021 were: 76.3 MXN/MWh (3.74 USD/MWh) for connections up to 220 kV,and 173.7 MXN/MWh (8.53 USD/MWh) for connections below 220 kV.[23] The mean tariff for all users in November 2017 was 86.07 USD/MWh, assuming an exchange rate of 18.91 MXN/USD on 16 November 2017.[18] From that date, the federal Government has endeavoured not to increase the electricity tariffs at more than the official yearly inflation rate.

SMALL HYDROPOWER SECTOR OVERVIEW

There is no legal definition of SHP in Mexico. However, a hydropower plant is considered eligible for incentives aimed at promoting clean and renewable energy projects when its capacity is up to 30 MW or when it has a power density of at least 10 W/m^2, which is the ratio of installed capacity to water surface in the reservoir.[25] As of May 2019, CRE had issued 148 permits to existing hydropower plants or new projects, although six permits have subsequently been either revoked or terminated. Of the remaining 142 permits, 110 are permits for SHP plants up to 30 MW, including operational plants as well as ongoing and planned projects.[18,26]

There are 69 SHP plants in operation in Mexico with a combined capacity of 699.3 MW and an authorized annual generation of 3,193.2 GWh. Of this total, 32 belong to CFE and 37 to other private or public entities. All of the SHP plants in operation are connected to the national electric grid.[26] No official nationwide estimate of SHP capacity up to 30 MW is available. Relative to the World Small Hydropower Development Report (WSHPDR) 2019, both installed and estimated potential capacity have remained constant, as no new SHP plants have been commissioned (Figure 3).[27] A partial list of operational SHP plants in Mexico is provided in Table 2.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Mexico (MW)**



Source: CRE,[26] WSHPDR 2019,[27] WSHPDR 2013,[28] WSHPDR 2016[29]

Table 2. **List of Selected Existing Small Hydropower Plants in Mexico**

Name	*Location*	*Capacity (MW)*	*Annual generation (GWh)*	*Operator*	*Launch year*
La Boquilla	Chihuahua	25.00	81.5	Generadora Fénix	2016
Santa Bárbara	Estado de México	22.53	3.0	Generadora Fénix	2016
Oviáchic	Sonora	19.20	92.1	Generadora Fénix	2016
Camilo Arriaga	San Luis Potosí	18.00	84.5	Generadora Fénix	2016
N/A	Veracruz	16.94	132.0	Generadora Fénix	2016
N/A	Sinaloa	15.00	39.0	CFE - Generación I	2015
Gral. Salvador Alvarado	Sinaloa	14.00	41.0	Generadora Fénix	2016
Planta Orizaba	Veracruz	10.00	24.7	Generadora Fénix	2016
Mocúzari	Sonora	9.60	40.8	Generadora Fénix	2016
Puente Grande	Jalisco	9.00	24.0	Generadora Fénix	2016
N/A	Jalisco	8.00	30.5	Generadora Fénix	2016
Luis M. Rojas	Jalisco	5.32	10.0	Generadora Fénix	2016
Colina	Chihuahua	3.00	8.2	Generadora Fénix	2016
Portezuelos I	Puebla	2.80	13.7	Generadora Fénix	2016
Ixtaczoquitlán	Veracruz	1.60	11.0	Generadora Fénix	2016
Electroquímica	San Luis Potosí	1.44	8.4	Generadora Fénix	2016
Bartolinas	Michoacán	0.75	2.3	Generadora Fénix	2016
Micos	San Luis Potosí	0.69	2.7	Generadora Fénix	2016
Itzícuaro	Michoacán	0.62	3.9	Generadora Fénix	2016

Source: CRE[26]

Additionally, there are 41 SHP plants under construction or waiting to start construction with a combined capacity of 452.5 MW and an authorized generation of 2,277.0 GWh. One of these plants belongs to CFE and 40 to other private or public entities.[26] A partial list of ongoing SHP projects is provided in Table 3.

Table 3. **List of Selected Ongoing Small Hydropower Projects in Mexico**

Location	*Capacity (MW)*	*Annual generation (GWh)*	*Operator*	*Planned launch year*	*Development stage*
Guerrero	30.0	150.0	Mexicana de Cobre	2013	Construction
Veracruz	26.0	118.0	Hidroeléctrica Solís	2014	Construction
Noroeste	30.0	191.7	Generadora Fénix	2016	Construction
Guerrero	30.0	146.2	Proyectos Hidroeléctricos de Puebla	2016	To start works
Puebla	27.4	108.8	Industrias Wack	2017	To start works

Source: CRE[26]

Note: Data are from 2019

For several decades, CFE has been conducting planning studies focused on identifying potential hydropower sites with an expected production greater than 40 GWh/year. In 2012, its inventory included 585 such sites, including 73 plants now in operation. The combined potential capacity of the remaining 512 sites was estimated at 41,132 MW, with a potential generation of 114,754 GWh/year and an average utilization factor of 32 per cent.[30]

In 1995, CONAE published a national estimate of SHP potential in Mexico of approximately 3,250 MW, considering plants with a capacity of between 2 MW and 10 MW.[31] However, this assessment was based on an incorrect extrapolation from data on other countries. Subsequently, the author of the original estimate stressed the urgent need to conduct a more rigorous assessment of the national SHP potential.[32] Nevertheless, up until the present day many official and academic documents have continued to cite the figure of 3,250 MW as a fact.

Subsequently, SENER has published an estimate of the total probable SHP potential of 2,700 MW, based on the aforementioned studies carried out by CFE.[33] This value was based on the combined capacity of 489 sites picked from the 512 in the CFE inventory, raising the utilization factor to 100 per cent and reducing the height of the dams. The methodology applied was of questionable quality and this estimate is largely uncertain.

Furthermore, there have been several official assessments of the SHP potential in natural streams of certain river basins, which, however, cover only a very small portion of the national territory. These studies have a widely varying degree of hydrological and topographical precision. At the low end of the precision spectrum, in 1995 a study was commissioned by CONAE of six watersheds on the coast of the Gulf of Mexico, covering 26,376 km^2, where a total of 100 SHP sites were identified using simplified techniques and data.[32] At the high end of the spectrum are the studies commissioned by CFE in 2007 for three watersheds, covering 29,259 km^2, where a total of 3,118 micro-, mini- and small hydropower sites were identified through applying a more advanced methodology.[34]

Taking into account the rugged relief and heavy rainfall patterns across the many river basins of Mexico which have not yet been studied, it can be assumed with high confidence that once a systematic and exhaustive assessment of the SHP theoretical, technical, economic and environmental potential is carried out, thousands of feasible sites will be identified, and that the total potential capacity will be considerably larger than the partial estimates available up to this point. A quick analysis of conditions for SHP development in Mexico reveals that, assuming a proportional hydropower potential with China and the EU, there could be between 9,800 and 11,500 viable hydropower plants in Mexico, with the majority being SHP plants. However, Mexico had only 100 plants of all sizes in operation as of 2019.[35,36]

The benefits that hydropower can offer the population of Mexico in terms of preservation of the environment, social well-being and economic resilience are of great importance. With the useful life of a single plant often exceeding 100 years, new hydropower projects could reach millions of families in large regions for several generations. Furthermore, demand for small-scale power generation in Mexico is significant. At the end of 2016, there were approximately 1.8 million inhabitants without access to electricity in rural communities, mainly due to their dispersion in mountainous areas. A part of this population could be served by generation from RES and SHP in particular.[17] At the same time, public awareness of the potential and objective impacts of SHP development is very limited, and prone to ideological and political manipulation promoted by competing industries. Even among professionals and energy sector officials, in Mexico it is not unusual to hear opinions stating that there is no more room for hydropower development, due to its supposed negative environmental and social effects.

RENEWABLE ENERGY POLICY

The regulation of the sustainable management of energy, clean energy obligations and the efficient use of energy is carried out by SENER, which is also involved in promoting the gradual energy transition in Mexico in compliance with relevant international agreements.[24]

Long-term goals established by existing legislation to raise the share of electricity generation from clean energy, including renewable and non-renewable sources, stipulated a 25 per cent share in 2018, a 30 per cent share in 2021, 35 per cent in 2024, 43 per cent in 2030 and 50 per cent in 2050.[11] As of 2021, Mexico had fallen behind on these targets. There are no explicitly defined targets for generation from clean RES.

Currently, projections for greenhouse gas (GHG) emissions associated with fossil fuel-based electricity generation in Mexico predict an increase from 84 $MtCO_2e$ in 2020 to 99 $MtCO_2e$ in 2034. The GHG emission factor of electricity from the SEN in 2020 was 0.494 tCO_2e/MWh.[11] The key legal frameworks shaping the policies of Mexico targeting GHG reduction include the Paris Climate Agreement, signed on 22 April 2016 and committing the country to a 22 per cent reduction by 2030, relative to the 2013 levels. There are other instruments reinforcing these policies, including the National Climate Change Strategy and the Transition Strategy to Promote the Use of Cleaner Technologies and Fuels. The goals outlined by these policies include increasing the scale and efficiency of generation from hydropower through the proper management of dams, the repowering of existing turbines and an increase in the number of hydropower plants. At the same time, distributed generation is a preferable option for rural areas, households, micro- and small businesses or shops in pursuit of a socially conscious energy transition.[11]

While there is no feed-in tariff (FIT) incentive scheme for RES in Mexico, there are other forms of incentivization. These include a 100 per cent tax deduction on the purchase of machinery and equipment for generation from RES, as well as a reduction of income tax for enterprises with projects on RES research and technology development.[37] Another incentive is a minimum required proportion of clean energy for participants in MEM transactions. It was set at 5 per cent of total electricity sold at the point of consumption in 2018, 5.8 per cent in 2019, 7.4 per cent in 2020, 10.9 per cent in 2021 and 13.9 per cent in 2022.[38,39] Finally, the requirement for a generation permit is waived for plants under 500 kW capacity.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The main legislation and regulations related to SHP were adjusted in the Energy Reform of 2013. These include the following:

- Political Constitution of Mexico (CPEUM);
- Law of the Electric Industry (LIE);
- Law of Energy Transition (LTE);
- Law of the Federal Commission of Electricity (LCFE);
- General Law of Ecological Balance and Environmental Protection (LGEEPA);
- Law of National Waters (LAN);
- Law of the Regulatory Commission of Energy (LCRE);
- General Law on Climate Change (LGCC).

The licensing process for SHP plants includes a sequence of steps starting with the creation of an enterprise and proceeding with federal permits in the environment, culture, indigenous people, water and electricity and energy sectors. In some cases, state-level environmental authorities may be involved rather than those at the federal level. Municipal authorities are involved in the site selection process for each of the project components. Specific licences required for SHP construction include the following:

- Constitutive act of the enterprise, with a Notary Public and Fiscal authority (SAT);
- Environmental impact assessment (EIA), with SEMARNAT, which includes a preventive report, particular EIA or regional EIA, depending on the project size, as well as a report on the land use change of forested land;
- Indigenous consultation with the Secretariat of the Interior (SEGOB);
- Water authorizations, with CONAGUA, including a surface water concession, federal zone use permit and a permit to carry out hydraulic infrastructure works in waterways and federal areas;
- Study of electric installations for power plants, with CRE, including a contract for interconnections;
- Municipal construction permits, with one or more municipalities involved;
- Power generation permit, with CRE.

The duration of the licensing process is very dependent on the attributes of each project, ranging between 18 and 30 months. The process can be costly due to the various detailed studies and designs which are required.[40]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Entities involved in the financing of SHP in Mexico include the following:

- Commercial banks;
- National development banks and programmes: Banobras, Nacional Financiera, FIRA;
- Multilateral development banks: World Bank, Inter-American Development Bank, Development Bank of Latin America and others;
- Private RES investment funds;
- Foreign export credit agencies (ECA);
- International cooperation agencies for rural RES projects;
- Equipment suppliers' credit.

Specific programmes targeting SHP development include funding by the National Council of Science and Technology (Conacyt), which issues annual calls for proposals of applied research and development projects related to the implementation of RES, emphasizing the participation of rural communities. Additionally, there is a technical cooperation agreement signed between Government entities of Mexico and China, involving the International Center on Small Hydro Power (ICSHP) of China and the National Institute of Electricity and Clean Energies (INEEL) of Mexico, as well as the Mexican Institute of Water Technology (IMTA), for a two-year programme starting in December 2020. From 2016 to 2019, IMTA led the Iberoamerican Thematic Network on Small-Scale Hydropower (REDHIDRO), which involved the participation of 19 groups from 11 countries in the region.[38]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Barriers to the development of SHP in Mexico include a variety of environmental, socio-political, regulatory, technical and financial factors:

- Environmental: a lack of a reliable national inventory of hydropower potential, unreliable official estimates and the lack of studies on integrated water resources management that incorporates SHP projects;
- Political and social: policies that favour other conventional and RES generation technologies, campaigns against SHP by pressure groups tied to competing commercial interests, a negative social perception of SHP due to lack of accurate information, insecurity in certain regions and disproportionate demands for compensation by some potential host communities;
- Regulatory: a convoluted licensing process, restrictions in regulated areas, delays in receiving indigenous

permits due to understaffing of responsible agencies, difficulties with receiving permits for development on existing infrastructure and risks associated with new upstream developments or legal challenges to ongoing or completed projects;
- Technical: the lack of accurate information on the grid as well as limited grid coverage and capacity, partial lack of specialized personnel, technical deficiencies in SHP projects at the pre-feasibility study phase and lack of domestic manufacturing capacity for SHP plant parts and equipment;
- Financial: the growing cost of the transmission service, lack of coverage and maintenance of access roads in areas with high hydropower potential, charges based on the volume of water used rather than the energy generated, lack of FITs coupled with the low electricity purchase price and a risk of further decline in prices due to auctions, demanding terms of commercial credit, lack of financing for prospection and pre-feasibility studies, difficulties in accessing GHG emissions reduction payments and the difficulty of valuation of positive externalities of SHP development.

Enablers for SHP development in Mexico can likewise be thought of in terms of the following broad categories:
- Environmental: abundant, if not rigorously quantified, potential as well the gradually declining domestic reserves of fossil fuels that Mexico highly depends on;
- Political: the imperative for achieving energy sovereignty, international and domestic commitments to GHG reductions and RES development, and the expectation of Mexican consumers of continuing low electricity prices;
- Domestic and international economy: increasing per capita consumption of electricity, unfulfilled electricity demand of certain communities and attractive export prices for electricity in the region;
- Regulatory and financial incentives: tax breaks and reductions, prioritization of grid connections for RES, ability to sell electricity directly to end users and waiver of generation permit for plants under 500 kW capacity;
- Technical: increasing incorporation of plants of intermittent generation into the grid, availability of skilled personnel in the construction and electrical power sectors and international technical cooperation agreements in the hydropower sector.

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Nicaragua

Laura Stamm, International Center on Small Hydro Power (ICSHP)

KEY FACTS

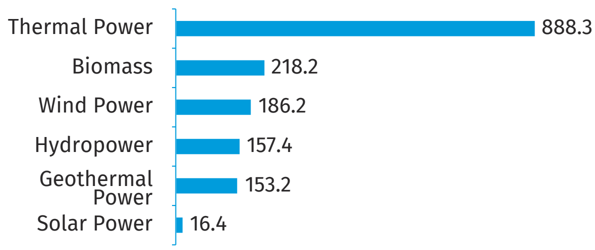
Population	6,624,554 (2020)[1]
Area	130,370 km[2 2]
Topography	The western part of the country is characterized by valleys dissected by low rugged mountains, including the Cordillera Entre Ríos, Cordilleras Isabelia and Dariense, Huapí, Amerrique and Yolaina. In the Cordillera Entre Ríos lies the highest peak of the country, Mogotón Peak at 2,103 metres. A string of 40 volcanoes, some of which are active, stretches from north-west to south-east along the Pacific coast. The eastern part of the country consists of wide low plains reaching 100 kilometres in width.[2]
Climate	In the east of Nicaragua, the climate is slightly cooler and wetter than in the west. The Pacific side of the country has two seasons: a rainy season, lasting from May to November, and a dry season, lasting from December to April. On the Caribbean side, the dry season is from March to May, while the rainy season lasts for nine months. Annual temperatures across the country average 27 °C. However, in the northern mountains the climate is cooler with an average temperature of 18 °C.[2]
Climate Change	As global temperatures rise, the natural cycle between dry and wet seasons in Nicaragua is anticipated to become more severe, causing increases in both droughts and floods. As a result, disasters such as landslides and fires, particularly in the rural regions, are expected to become more prevalent. In addition, the water temperature of lakes and rivers has been rising and will continue to do so, which will affect water quality and thermal structure.[3]
Rain Pattern	Annual precipitation averages 1,905 mm on the Pacific side of the country and 3,810 mm on the Caribbean side.[2]
Hydrology	The central mountains of Nicaragua form the main watershed. The rivers flowing to the west of it are relatively short and drain into the Pacific Ocean or Lakes Managua and Nicaragua. The west is the region where the major lakes are located, with Lake Nicaragua being the largest lake in Central America. The most important rivers in this part of the country are the Negro, Estero Real and Tamarindo. The rivers to the east of the mountains tend to be longer and empty into the Caribbean. The main rivers here are the Coco (475 km), Río Grande de Matagalpa (430 km), Prinzapolka (254 km), San Juan (200 km), Indio (90 km), Escondido (89 km) and Maíz (60 km).[2]

ELECTRICITY SECTOR OVERVIEW

In 2020, electricity generation in Nicaragua was approximately 3,797 GWh, 71 per cent of which was sourced from renewable energy. Thermal power, primarily fuel oil and diesel, accounted for 29 per cent, geothermal power for 21 per cent, biomass for approximately 19 per cent, hydropower for just above 15 per cent, wind power for almost 15 per cent and solar power for the remaining almost 1 per cent (Figure 1).[4,5] An additional 1,071 GWh of electricity was imported, and none was exported during 2020.[6]

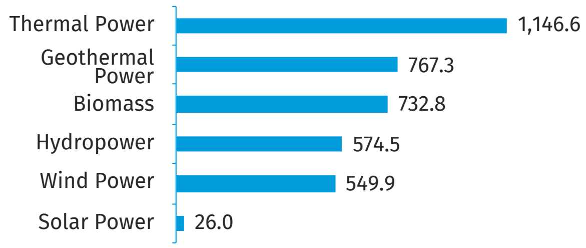
As of December 2020, the total installed capacity of Nicaragua was approximately 1,620 MW. Thermal power accounted for the majority at almost 55 per cent of the total installed capacity, biomass accounted for approximately 13 per cent, wind power for 11 per cent, geothermal power and hydropower for approximately 10 per cent each and solar power for just under 1 per cent (Figure 2).[7] Approximately 99 per cent of the total installed capacity fed the National Interconnected System, which serves the mainland, whereas the National Island System accounted for the remaining 1 per cent of capacity. While the mainland uses a mix of all of these six sources, the island system relies on just thermal power (88 per cent) and solar power (12 per cent). The total available capacity of the country's electricity system was 18 per cent lower than installed capacity, at 1,329 MW.[7]

Figure 1. **Annual Electricity Generation by Source in Nicaragua in 2020 (GWh)**



Source: INE[5]

Figure 2. **Installed Electricity Capacity by Source in Nicaragua in 2020 (MW)**

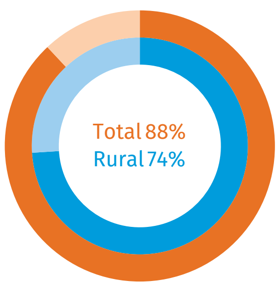


Source: INE[7]

In the 1990s, the electricity sector of Nicaragua underwent a restructuring, whereby the state-owned Nicaraguan Electricity Company (ENEL) was unbundled and partially privatized. The reform resulted in the creation of four generation companies (GEMOSA, GEOSA, HIDROGESA and GECSA), two distribution companies (DISNORTE and DISSUR) and one transmission company (ENTRESA). Two of the generation companies, HIDROGESA and GECSA, were kept public, while GEMOSA and GEOSA fully privatized. In the years since the initial breakup of ENEL, several smaller private generation companies have been established. Electricity transmission remains public, fully managed by state-owned ENTRESA. The two distribution companies were sold to the Spanish company Unión Fenosa, which originally covered the western, central and northern parts of the country, while the ENEL remained responsible for the eastern regions. [8] Since the beginning of the 2000s, however, new private distribution companies have been created and have acquired concession over many of the regions. Currently, there are 17 concessional areas of electricity distribution serviced by 14 different companies.[9]

The electricity sector is regulated by the Nicaraguan Energy Institute (INE). The National Load Dispatch Committee (CNDC) is the electricity market operator and the Ministry of Energy and Mines (MEM) oversees energy policy and planning. Electricity is traded in spot and wholesale markets, which allows the trading of electricity through long-term contracts between generating companies and distributing companies or large users.[10]

Figure 3. **Electrification Rate in Nicaragua in 2020 (%)**



Source: World Bank[12]

In recent years, the electricity sector of Nicaragua has been prioritized in national plans and initiatives such as the Rural Electrification Policy of 2005 as well as in the Sustainable Energy for All initiative of 2012. The Government has made significant efforts to improve the reliability of electricity supply as well as access in vulnerable areas.[11] The overall electrification rate in Nicaragua reached 88 per cent in 2019, with over 99 per cent in urban areas and 74 per cent in rural areas (Figure 3).[12]

Electricity tariffs vary with type, usage and distribution concession. The most common tariffs carried out by DISNORTE and DISSUR as of February 2022 are as shown in Table 1. For low-income households that use less than 150 kWh, a subsidized tariff is available.[13]

Table 1. **Electricity Tariffs in Nicaragua**

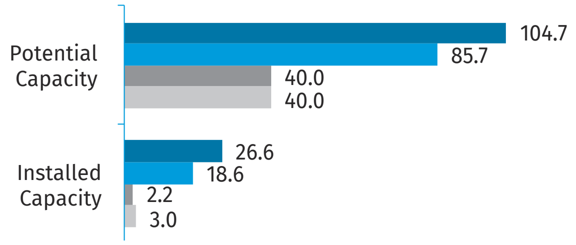
Type	*Usage*	*Cost (USD/kWh)*
Residential	*First 25 kWh*	*0.07*
	Next 25 kWh	*0.16*
	Next 50 kWh	*0.17*
	Next 50 kWh	*0.23*
	Next 350 kWh	*0.23*
	Next 500 kWh	*0.36*
	Additional above 1,000 kWh	*0.41*
Commercial	*Contracted with less than 25 kW*	*0.17*
	Contracted with more than 25 kW	*0.18*
Industrial	*Contracted with less than 25 kW*	*0.15*
	Contracted with more than 25 kW	*0.17*

Source: INE[13]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Nicaragua is up to 10 MW. The installed capacity of SHP was 26.6 MW in 2019, while the potential is estimated to be 104.7 MW, indicating that approximately 25 per cent has been developed.[14,15] Compared to the World Small Hydropower Development Report (WSHPDR) 2019, installed capacity has increased by 44 per cent, a total of 8.0 MW (Figure 4). This is a result of the completion of three additional plants: 5.70 MW San Martin, 1.48 MW Yakalwas and 0.85 MW La Camaleona. Furthermore, due to the identification of another three locations to develop SHP in the upcoming years, total potential capacity has also increased by 19 MW.

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Nicaragua (MW)**



Source: MEM,[14] MEM,[15] WSHPDR 2019,[16] WSHPDR 2016,[17] WSHPDR 2013[18]

As of 2019, there were 17 operational SHP plants with a combined capacity of 26.64 MW (Table 1). There are another 20 potential sites throughout Nicaragua that are planned to be developed in the future, totaling 78.01 MW (Table 2).

Table 1. **List of Existing Small Hydropower Plants in Nicaragua**

Name	*Location*	*Capacity (MW)*
San Martin	El Tuma-La Dalia, Matagalpa	5.70
El Diamante	San Ramón Matagalpa	5.00
Salto Grande	Bonanza, North Atlantic Autonomous Region	2.80
Las Cañas	Matagalpa, Matagalpa	2.70
Siempre Viva	Bonanza, North Atlantic Autonomous Region	2.50
El Wawule	San Ramón Matagalpa	1.72
Yakalwas	Wiwili, Jinotega	1.48
El Sardinal	El Tuma La Dalia, Matagalpa	1.20
El Bote	El Cuá, Jinotega	0.96
La Camaleona	San José de Bocay, Jinotega	0.85
Bilampí-Musun	Río Blanco, Matagalpa	0.34
Tichana	Ometepe, Rivas	0.33
Kubalí-La Florida	Waslala, North Atlantic Autonomous Region	0.30
San José Bocay (Aprodelbo)	Jinotega	0.26
Las Nubes El Naranjo	Waslala, North Atlantic Autonomous Region	0.22
Rio Bravo Puerto Viejo	Waslala, North Atlantic Autonomous Region	0.18
1ro de Febrero	El Tuma, Matagalpa	0.10
Total		**26.64**

Source: MEM[14,15]

Table 2. **List of Planned Small Hydropower Projects in Nicaragua**

Name	*Location*	*Capacity (MW)*
Cuasquil	Esquipulas, Matagalpa	10.00
Santa Elisa	Matagalpa	8.70
La Esperanza	Matagalpa	7.00
Coco Torres	San Juan de Rio Coco, Madriz/ Jinotega	6.30
Quililon	El Tuma-La Dalia, Matagalpa	6.00
El Tortuguero	El Tortuguero, South Atlantic Autonomous Region	5.50
Zopilota	El Tuma-La Dalia, Matagalpa	5.10
El Ayote	Chontales y South Atlantic Autonomous Region	5.00
El Tigre	El Tuma-La Dalia, Matagalpa	5.00
Monte Cristo	San Sebastián de Yalí, Jinotega	4.00
El Mono	Jinotega	3.30
Colombina	Santa Ma de Pantasma, Jinotega	2.70
El Loro	El Tuma-La Dalia, Matagalpa	2.50
La Mora	El Tuma-La Dalia, Matagalpa	1.90
Las Canoas	Teustepe, Boaco	1.79
Salto Los Chepes	San Rafael del Sur, Managua	0.90
San Francisco	El Tuma-La Dalia, Matagalpa	0.90
Wapí-Salto Mollejones	El Rama, South Atlantic Autonomous Region	0.77
San José - El Malacate	Pantasma, Jinotega	0.42
La Unión - Salto Negro	Chontales	0.23
Total		**78.01**

Source: MEM[14,15]

RENEWABLE ENERGY POLICY

The Government of Nicaragua aims to increase the share of renewable energy sources (hydropower, wind power, solar power, biomass and geothermal power) in the energy mix. The commitment began in the early 2000s, when a series of policies and laws were first implemented. The National Energy Policy of 2004 established the policy framework for the promotion of renewable energy. In 2005, Law 532 on the Promotion of Electricity Generation with Renewable Resources declared that it is of national interest to generate electricity using renewable energy sources. The Law also provides financial incentives to encourage the establishment of renewable energy plants including exemption of import taxes, local taxes, value added taxes and income taxes for the first seven years of a new energy plant's life. It also obligates utilities to buy energy from renewable energy plants via a bidding process.[19]

Intertwining the goals to increase renewable energy as well as to increase general access to electricity, in 2005 the country released the Rural Electrification Policy, which promotes the expansion of electricity to rural areas, with special prioritization on using renewable sources.[19] To complement this policy, Law 554 on Energy Stability passed in 2005, defined measures to ensure that energy is available to all income levels, providing subsidies to residential usage of 150 kWh or less per month, and created the Fund for Energy Development and the Energy Crisis Fund, all of which prioritizes renewable energy. The law further insists that the Government should seek international funding for renewable energy generation projects.[20]

The Plan for Electricity Generation Expansion 2016–2030 provides a comprehensive set of plans and goals for the country's electricity sector. The plan outlined the expectation that by 2030, an additional 1,223 MW of new capacity will be added to the country's electricity system. This includes 138 MW of biomass, 74 MW of solar photovoltaics (PV), 143 MW of wind power, 135 MW of geothermal power, 271 MW of reservoir-based hydropower and 22 MW of run-of-river hydropower capacity. However, the plan also foresees 440 MW of new thermal power capacity, consisting of fuel oil and natural gas plants. Nonetheless, the plan's goal was to reduce the share of thermal power generation in the country's energy mix from 45 per cent in 2018 to 36 per cent in 2023 and to 27 per cent in 2030, with the remaining share being from renewable energy.[21] In 2020, the actual electricity generation in the country was 29 per cent thermal energy and 71 per cent renewable energy, demonstrating steady progress towards the 2030 goal.[5]

Among all renewable energy sources, hydropower is expected to see the greatest addition of new capacity in the coming decade according to the plan. In general, the Government has declared hydropower development to be an important part of its energy policy and a favourable legal framework and an attractive incentive structure have been established for hydropower projects up to 5 MW.[10]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Law 476 for the Promotion of the Hydroelectric Subsector stipulates that hydropower projects below 1 MW do not need a water concession. Instead, producers can obtain a permit for a period of 15 years. For plants with capacities of 1–5 MW, a simplified procedure applies for obtaining a water concession from the Ministry of Development, Industry and Trade. Additionally, Law 217 for the Protection of Environment and Natural Resources stipulates that projects with capacities below 5 MW do not need an environmental impact assessment.[10]

COST OF SMALL HYDROPOWER DEVELOPMENT

The costs associated with the development of SHP plants in Nicaragua are site-specific and depend on various factors. The total costs of three hydropower projects that were completed in 2018 are shown in Table 3.

Table 3. **Costs of Selected Small Hydropower Projects in Nicaragua**

Name	*Capacity (MW)*	*Total cost (USD million)*	*Cost per MW (USD million/MW)*
San Martin	5.70	19.4	3.4
Yakalwas	1.48	7.5	5.0
La Camaleona	0.85	3.8	4.4

Source: MEM[15]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

SHP development in Nicaragua is mainly financed by private investors, international firms, or international organizations such as the European Investment Bank, the Inter-American Investment Bank and the Central American Bank for Economic Integration. The county's investment promotion agency, PRONicaragua, is an integral part of foreign direct investment and facilitates the process with potential investors.[22]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The Plan for Electricity Generation Expansion 2016–2030 expresses concern for the effects of climate change on the country's hydropower. Due to the increased prevalence of droughts expected by 2030, the contribution of natural water resources to hydropower plants may decrease by up to 13 per cent. This decrease in input could possibly result in an up to 30 per cent decrease in power generation.[21]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Barriers hindering the development of SHP in Nicaragua include:

- Difficulty in accessing funding because of the high initial cost of projects. Commercial finance is needed over the long-term, but, in general, financial assistance is short-term with high interest rates;
- The duration of power purchase agreements is too short to motivate SHP project development. Therefore, it is difficult to make long-term investment decisions;

- The approved fiscal incentives for hydropower projects do not create a level playing field for hydropower development compared to thermal power projects, since the latter continue to be highly subsidized;
- Lack of experience and technological knowledge in the implementation of SHP plants.[10,17]

Enablers encouraging the development of SHP in Nicaragua include:

- Strong presence of political will and dedication to the transition to renewable energy and climate action;
- Very limited restrictions to foreign direct investment in the energy sector;
- Between lakes, lagoons and rivers, the country's surface area is 10 per cent water, offering great possibilities to explore for more potential hydropower sites;
- It has been estimated that there is approximately 3,760 MW of total potential of hydropower generation throughout the country given a 100 per cent plant availability scenario, larger than any other renewable resource in the country. Currently less than 5 per cent of that is being utilized leaving an abundance of untapped potential;
- As rural electrification is underway, electricity demand is expected to increase accordingly.[10,22]

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Panama

José Fábrega,[a,b] Denise Delvalle,[a,b] and Alexis Baúles[b] National Research System of Panama (SNI)[a,b] Hydraulic and Hydrotechnical Research Center, Universidad Tecnológica de Panamá

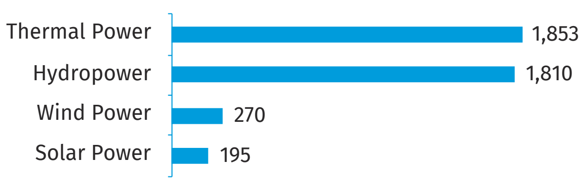
KEY FACTS

Population	4,218,808 (2019)[1]
Area	75,420 km^2 [2]
Topography	There are rugged mountains to the west and towards the Caribbean Sea and rolling hills and vast plains by the Pacific Coast. The lowlands cover approximately 70 per cent of the country's territory. The highest point in Panama is the Volcán Barú, which rises to 3,475 metres above sea level.[2]
Climate	Panama has a tropical climate with two seasons, dry and rainy. The variations in climatic conditions depend on the region and the altitude. Winter is the wet season and lasts from May to November, while summer is the dry season and lasts from December to April, with March and April ordinarily being the warmest months. The annual average temperature in Panama ranges between 23 °C and 27 °C for the coastal areas and in the interior, while at higher altitudes it can drop to 19 °C. In general, temperatures are reflective of the country's tropical climate profile and increase 0.56 °C for every 100 metres of altitude. [3]
Climate Change	Observed climate change impacts in Panama have included intense rains during the dry season, long periods of drought and sea level rise. Increased energy demand driven by rising temperatures has also been observed. The projected climate change impacts by the end of the 21st century include loss of crops and soils, loss of the coastline as a result of storm surges, as well as more severe flooding in large urban centres, with damage to infrastructure and services.[4]
Rain Pattern	Panama has a yearly average precipitation of 2,928 mm. The Pacific region shows a wet season pattern from May to November. For the Atlantic region, precipitation is continuous throughout the year.[5,6]
Hydrology	There are approximately 500 rivers in Panama in 52 watersheds. Seventy per cent of the rivers, including most of the longer streams, run to the Pacific coast, while 30 per cent run to the Atlantic coast.[7]

ELECTRICITY SECTOR OVERVIEW

The total installed electricity capacity of Panama was 4,128 MW in 2020, representing a 26 per cent increase since 2017. Thermal power plants provided 1,853 MW (45 per cent) of the total, hydropower provided 1,810 MW (44 per cent), wind power provided 270 MW (7 per cent) and solar power provided 195 MW (5 per cent) (Figure 1).[8]

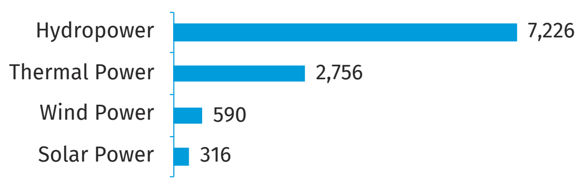
Figure 1. **Installed Electricity Capacity by Source in Panama in 2020 (MW)**



Source: ASEP[8]

Annual generation of electricity in Panama in 2020 amounted to approximately 10,887 GWh. Hydropower accounted for 7,226 GWh (66 per cent) of the total, thermal power accounted for 2,756 GWh (25 per cent), wind power accounted for 590 GWh (5 per cent) and solar power accounted for 316 GWh (3 per cent) (Figure 2). Renewable energy sources (RES) thus accounted for 74 per cent of all electricity generation in the country in 2020. Exports of electricity in 2020 amounted to 524 GWh, while imports were 86 GWh.[8]

Figure 2. **Annual Electricity Generation by Source in Panama in 2020 (GWh)**

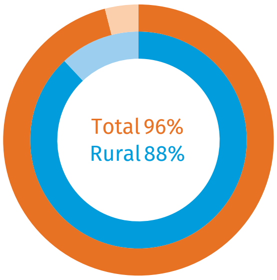


Source: ASEP[8]

Note: Values were calculated based on percentages quoted in the source.

The nationwide rate of electricity access in Panama was nearly 96 per cent in 2019 and 88 per cent in rural areas (Figure 3).[9] Electricity consumption in 2020 amounted to 9,521 GWh and an additional 125 GWh were accounted for by self-consumption.[10]

Figure 3. **Electrification Rate in Panama in 2019 (%)**



Source: World Bank[9]

The National Secretariat of Energy, established by Law 43 on 23 April 2018, is responsible for overseeing the energy sector in Panama.[11] The Rural Electrification Office (OER), operating under the supervision of the Ministry of Public Works, is tasked with providing energy to rural, isolated areas not connected to the national grid. The OER works to increase electricity access in rural areas both by extending electrical networks as well as by developing local generating capacity through projects employing RES, including small hydropower (SHP).[12,13]

Key legislation regulating the energy sector in Panama includes Law No. 6 introduced on 3 February 1997 (and its later amendments) as well as Decree Law No. 22 of 1998.[11,14,15,16] Following the privatization of the public electricity utility in 1998, the Electric Transmission Company (ETESA), a public limited company, was put in charge of the transmission and distribution of electricity. ETESA is additionally responsible for grid expansion planning, construction of new transmission and distribution lines and grid maintenance.[17] The remuneration for the services carried out by ETESA is likewise regulated by Law No. 6 of 1997.[14]

The electricity grid of Panama consists of three main transmission lines, all located along the Pacific coast. All three lines are complete, fully operational and operating at full capacity.[17] Targets for the ongoing and future expansion of the electricity grid are outlined in the National Interconnected System Expansion Plan 2019–2033. The Plan consists of three major documents:

- Basic studies including forecasts of energy demand and power at the level of the Main Transmission System;
- The Indicative Generation Plan, the objective of which is to provide information on the expansion of generation capacities and the evolution of the generation sector, as well as to provide an analysis of the current supply situation and potential energy alternatives, taking into account multiple variables including energy demand and resources, hydrology, and availability and costs of fuels, among others;
- The Expansion Plan of the Transmission System, which will become mandatory once approved by the National Public Service Authority (ASEP).[18]

Additionally, Panama is developing interconnection strategies with neighbouring countries in Central America through the Central American Electric Interconnection System (SIEPAC). This system was officially inaugurated in December 2014 and includes Guatemala, Honduras, Nicaragua, El Salvador, Costa Rica and Panama. With an investment of USD 500 million USD, the system consists of one line of 230 kV connected to capacities of 300 MW. This initiative has great potential, although exchanges have been very modest so far. A separate integration plan with Colombia has also been proposed, which is expected to produce price advantages and involves the introduction of a virtual generator with a capacity of 400 MW.[19,20]

The largest independent electricity producers in Panama as of 2020 were Minera Panama mining company with an installed capacity of 300 MW and the Panama Canal Authority with an installed capacity of 213 MW, 72 per cent of which was provided by thermal power plants and 28 per cent by hydropower plants.[8,21]

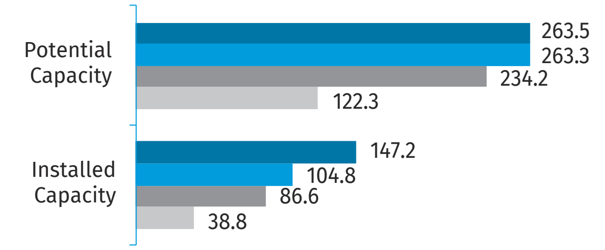
Electricity tariffs in Panama are set on a monthly basis by the ASEP and include a variable price that fluctuates with the fuel market prices. From 2016 to 2021, the average electricity tariff in Panama fluctuated between 0.163 USD/kWh to 0.217 USD/kWh before subsidies. Subsidized electricity tariffs have ranged from a low of 0.149 USD/kWh in December 2020 to a high of 0.187 USD/kWh in December 2019.[22]

SMALL HYDROPOWER SECTOR OVERVIEW

The Latin American Energy Organization (OLADE) defines SHP plants as hydropower plants with a capacity of up to 5 MW, while the legal framework of Panama provides incentives for hydropower plants up to 20 MW.[23,24] However, for the sake of comparison with previous editions of the World Small Hydropower Development Report (WSHPDR), the current report uses the up to 10 MW definition for SHP.

The total installed SHP capacity up to 10 MW in Panama was 147.2 MW as of March 2021, provided by 24 SHP plants, while an additional 116.2 MW were available in the form of ongoing and planned SHP projects as well as potential SHP sites.[25,26] The total SHP potential capacity of the country is thus estimated at nearly 263.5 MW. Relative to the WSHPDR 2019, installed SHP capacity in the country has increased by 40 per cent due to the construction of several new SHP plants. Potential capacity has meanwhile remained virtually unchanged, as ongoing development has included previously-identified potential sites. (Figure 4).[27] A partial list of existing SHP plants is provided in Table 1.

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Panama (MW)**



Source: ASEP,[25,26] WSHPDR 2019,[27] WSHPDR 2013,[28] WSHPDR 2016[29]

Table 1. **List of Selected Existing Small Hydropower Plants in Panama**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
San Andrés	Chiriquí	10.00	N/A	Desarrollos Hidroeléctricos Corp.	2021
Bajos del Toluma	Chiriquí	6.30	Run-of-river	Hidroeléctrica Bajos el Toluma, S.A.	2018
La Cuchilla	Chiriquí	7.62	Run-of-river	Hidro Piedra, S.A.	2018
Bugaba 2	Chiriquí	5.86	Run-of-river	Empresa Nacional de Energía, S.A. (ENADESA)	2016
Las Cruces	Veraguas	9.38	Run-of-river	Corporación de Energía del Istmo Ltda, S.A. (CEISA)	2015
Bugaba I	Chiriquí	3.29	Run-of-river	Empresa Nacional de Energía, S.A.	2014
San Lorenzo	Chiriquí	8.70	Run-of-river	Hidroeléctrica San Lorenzo, S.A.	2014
Perlas Norte	Chiriquí	10.00	Run-of-river	Las Perlas Norte, S.A.	2013
Perlas Sur	Chiriquí	10.00	Run-of-river	Las Perlas Sur, S.A.	2013
Mendre 2	Chiriquí	8.12	Run-of-river	Electrogeneradora del Istmo, S.A.	2013
El Fraile	Coclé	5.31	Run-of-river	Hidroibérica, S.A.	2012
Los Planetas I	Chiriquí	4.75	Run-of-river	Saltos del Francoli, S.A.	2011
Macano	Chiriquí	5.80	Run-of-river	Hidro Boquerón, S.A.	2010
Paso Ancho	Chiriquí Viejo	6.00	N/A	Paso Ancho Hydro Power Corp.	2010
Los Algarrobos	Chiriquí	9.86	Reservoir	Empresa de Energía y Servicios, S.	2009
Antón III	Coclé	1.40	Reservoir	Hydro Panamá, S.A.	2009
Concepción	Chiriquí	10.00	Reservoir	Isthmus Hydro Power, Corp.	2008
Candela I	Chiriquí	0.53	Reservoir	Café de Eleta, S.A.	2006
Antón II	Coclé	1.40	Reservoir	Hydro Panamá, S.A.	2003
Dolega	Chiriquí	3.12	Reservoir	Empresa de Energía y Servicios, S.A.	2001

Source: ASEP[25]

There was a total of nine SHP projects in various stages of development in Panama as of 2021, with a planned capacity of 52.4 MW.[26] However, many of them are currently suspended, with the proposed launch dates no longer relevant. Several of the ongoing projects are listed in Table 2.

Table 2. **List of Selected Ongoing Small Hydropower Projects in Panama**

Name	*Location*	*Capacity (MW)*	*Developer*	*Planned launch year*	*Development stage*
Chuspa	Chiriquí, Boquerón, Paraiso y Guayabal	10.00	Navitas International, S.A.	2020	Under construction
Colorado	Chiriquí, Bugaba, Volcán	5.14	Hidroeléctrica Barriles, S.A.	2017	Final Design, Pending of Approval
India Vieja	Chiriquí, Boquete, Caldera	2.00	Darrin Business, S.A.	2017	Construction Hold
Terra 4-Tizingal	Chiriquí, Renacimiento, Montelirio	4.50	Hidroeléctrica Tizingal, S.A.	2017	Final Design
Rio Piedra	Colón, Portobelo, Portobelo	9.00	Hidroelectrica Río Piedra, S.A.	2015	Design; Environmental Impact Assessment study under review

Source: ASEP[26]

Additionally, 13 sites were considered potential prospects for SHP development, with a total potential capacity of 63.9 MW.[26] Several sites are provided in Table 3.

Table 3. **List of Selected Potential Small Hydropower Sites in Panama**

Name	*Location*	*Potential capacity (MW)*
El Recodo	Boca del Monte, San Lorenzo, Chiriquí	9.94
Gariche 2-3	San Andrés, Bugaba, Chiriquí	9.60
Chiriquí	Caldera, Boquete, Chiriquí	7.92
Caña Blanca	Los Ángeles, Gualaca, Chiriquí	7.85
Gariche	Volcán, Bugaba, Chiriquí	6.47

Source: ASEP[26]

RENEWABLE ENERGY POLICY

Panama has committed to achieving Sustainable Development Goal (SDG) 7 through promoting an energy transition policy and electric mobility. Likewise, Panama ratified the Paris Climate Change Agreement (PCCA) in September 2016, committing itself to reducing greenhouse gas (GHG) emissions.[30] The National Determined Contribution (NDC) of Panama set a target of increasing electricity generation from RES by 30 per cent by the end of 2050, relative to 2014. In 2020, Panama presented an updated NDC, which included targets of an 11.5 per cent emissions reduction by 2030 and a 24 per cent reduction by 2050, relative to the trend under the business-as-usual scenario.[31]

In addition to international agreements on GHG reductions and sustainable development, the commitment of Panama to RES development is motivated by rising electricity demand and the high cost of electricity in the country. In April 2011, Law No. 44 was adopted with the aim of promoting various forms of RES with a particular focus on wind power. The law provides for the application of long-range modelling of alternative energy development strategies in a variety of possible combinations. The Law was further developed with the passage of Law No. 18 in March 2013.[15,32]

The COVID-19 pandemic has contributed to delays in the implementation of ongoing projects and the development of new projects in the electricity sector, resulting in a negative impact on the national electricity market. Two new regulations, MIPRE-2020-0015448 and its modification MIPRE-2021-002034, were adopted between 2020 and 2021 to address this issue and guarantee the security of the electricity supply by outlining measures for short-term contracting of power and energy.[33,34]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Along with promoting other RES, Law No. 45-2004 established incentives for SHP projects of up to 20 MW capacity. These include:

- SHP plants up to 10 MW are allowed to sell generated electricity both directly and indirectly;
- SHP projects between 10 MW and 20 MW are exempt from paying import taxes and levies on the first delivered 10 MW for 10 years, including the Tax on the Transfer of Personal Property and Provision of Services for the importation of equipment, machinery, materials and spare parts;
- SHP projects up to 10 MW can qualify for a subsidy of the original investment costs of up to 25 per cent, calculated in terms of a reduction of equivalent tons of CO_2 emissions per year, as well as a tax exemption of up to 5 per cent of the total value of direct investment in connected infrastructure to be transferred to public ownership (roads, bridges, sewer lines, etc.).[24]

COST OF SMALL HYDROPOWER DEVELOPMENT

SHP development in Panama relies primarily on the private sector. The construction cost of the 4.95 MW Los Planetas-1 SHP plant in Chiriqui province was USD 21.3 million, or 4,303 USD/kW.[35] Meanwhile, the estimated value of the 6.3 MW Bajos de Toluma SHP plant was USD 22.4 million in 2017, or 3,556 USD/kW.[36]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Although there is a favourable legal framework in Panama granting fiscal incentives to SHP plants, development of the SHP sector is not significant.

The most important barrier to SHP development in the country is the lack of interest from private finance in supporting investment in SHP. As a result, rural communities are almost exclusively dependent on state financing for electricity sector development, including SHP.

Factors enabling SHP development in the country include:

- A solidly established hydropower sector with many operational SHP plants, most constructed in the last few decades;
- Fiscal incentives in the form of tax exemptions provided for SHP;
- Existing SHP projects that have stalled at various stages of implementation and may welcome additional financing;
- An abundance of identified prospective sites for new SHP development.

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2.3. South America

Countries: Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, French Guiana, Guyana, Paraguay, Peru, Suriname, Uruguay, Venezuela

INTRODUCTION TO THE REGION

Electricity generation in South America is dominated by thermal power and large hydropower. Brazil is the largest electricity producer in South America and accounts for approximately half of the region's total installed capacity and 60 per cent of the installed hydropower capacity. Brazil, Argentina, Chile, Peru and Uruguay all have highly diversified electricity sectors with significant installed capacities of solar power, wind power, bioenergy and other renewable energy sources (RES) supplementing hydropower and thermal power capacities. In addition, Brazil and Argentina operate the only nuclear power plants in the region. Other countries in South America rely primarily on a mix of hydropower and thermal power, with RES other than hydropower playing a relatively minor role.

Hydropower plays a particularly prominent role as the single largest source of electricity generation in Brazil, Colombia, Ecuador, Paraguay, Peru and Uruguay. In Paraguay, hydropower accounts for nearly 100 per cent of installed capacity and annual electricity generation and enables the country to export more than half of its annual electricity production to Brazil and Argentina. In other countries in the region, thermal power is the dominant energy source, while hydropower plays a supplementary role, with the exception of Guyana, where the installed capacity and annual generation of hydropower are negligible. Under the framework of the Renewables in Latin America and the Caribbean (RELAC) initiative, 12 countries in the region have committed to achieving a 70 per cent share of renewable energy sources in the regional energy mix by 2030, with hydropower expected to play a key role. Brazil is expected to continue to dominate the hydropower sector of South America through the current decade.

Electricity access is high across South America, at or approaching 100 per cent in most countries in the region. There is a high degree of cooperation among countries in cross-border power transmission and generation of electricity. For example, Bolivia, Chile, Colombia, Ecuador and Peru participate in the Andean Interconnection System (SINEA), which aims to integrate the regulatory frameworks, interconnections and electricity markets of the member states, while Paraguay operates several hydropower plants jointly with Brazil and Argentina.

An overview of the electricity sectors of the countries in the region is provided in Table 1.

Table 1. **Overview of South America**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Argentina	45	100	100	41,952	134,177	11,344	30,350
Bolivia	12	88	72	3,484	9,531	1,073	3,251
Brazil	212	100	100	177,300	626,300	109,315	397,900
Chile	19	N/A	N/A	26,653	70,828	6,806	18,263
Colombia	48	97	83	17,432	69,324	11,893	49,837
Ecuador	18	100	100	8,725	31,248	5,099	24,875
French Guiana	0.3	N/A	N/A	340	906	118	535
Guyana	1	92	90	348	1,134	0.02	N/A
Paraguay	7	100	100	8,816	46,373	8,810	46,371
Peru	33	N/A	N/A	15,371	49,187	5,551	29,318
Suriname	1	98	96	502	2,368	189	1,105
Uruguay	3	100	99	4,920	16,088	1,538	8,108
Venezuela	28	100	100	34,165	109,000	16,228	N/A
Total	-	-	-	**340,008**	-	**177,964**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in South America varies from country to country. The up to 10 MW definition is used in Ecuador and French Guiana, while Bolivia and Guyana have both adopted the up to 5 MW definition in line with the definition proposed by the Latin American Energy Organization (OLADE). For other countries in the region, the definition of SHP includes larger plants. Chile, Colombia and Peru define SHP as plants of up to 20 MW, Brazil uses the up to 30 MW definition, and Argentina, Paraguay and Uruguay use the up to 50 MW definition. No official definition of SHP exists in Suriname or Venezuela.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Argentina	Up to 50 MW	510.0	N/A	97.0	430.0
Bolivia	Up to 5 MW	N/A	N/A	99.1	99.1*
Brazil	Up to 30 MW	6,324.6	35,765.0	1,608.2	3,737.8
Chile	Up to 20 MW	618.0	5,145.0	304.0	2,995.0
Colombia	Up to 20 MW	900.8	N/A	234.6	4,946.0
Ecuador	Up to 10 MW	112.7	356.3	112.7	356.3
French Guiana	Up to 10 MW	5.5	34.5	5.5	34.5
Guyana	Up to 5 MW	0.02	24.2	0.02	92.0
Paraguay	Up to 50 MW	0.0	116.3	0.0	N/A
Peru	Up to 20 MW	503.8	3,500.0	N/A	N/A
Suriname	N/A	N/A	N/A	0.0	2.7
Uruguay	Up to 50 MW	0.0	231.5	0.0	208.0
Venezuela	N/A	N/A	N/A	1.4	49.7
Total	-	-	-	**2,462.6**	**12,951.1**

Source: *WSHPDR 2022*[1]

Note: *Based on installed capacity.

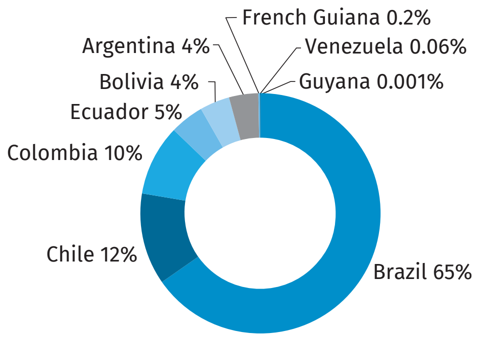
The total installed capacity of SHP of up to 10 MW in South America is 2,462.6 MW, while potential capacity is estimated at 12,951.1 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has increased by three times, mainly due to the inclusion of data on the installed capacity for SHP of up to 10 MW in Brazil. At the same time, the potential capacity has decreased by nearly 55 per cent, mainly due to a drastic downward reassessment of the SHP potential of Colombia based on more recent data.

Although hydropower potential in South America is considerable, SHP plays a relatively minor role in the electricity generation mix of most countries in the region due to heavy focus on large hydropower development, accounting for no more than 10 per cent, and usually closer to 2–5 per cent, of the countries' total installed hydropower capacities. The one exception to this pattern is Guyana, where the entire installed hydropower capacity is composed of a single micro-hydropower plant.

Brazil leads the region in installed capacity of SHP of up to 10 MW, and actively pursues SHP development both under the up to 10 MW definition as well as under the local definition of up to 30 MW. Chile, Columbia and Ecuador have also seen considerable recent expansion of SHP capacity off up to 10 MW, while Peru has dramatically increased its capacity of SHP of up to 20 MW. In other countries in the region, significant development in the SHP sector has been lacking and the reported installed SHP capacity of several countries including Bolivia, French Guiana and Suriname has decreased as a result of access to better data.

The national share of regional installed SHP capacity by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

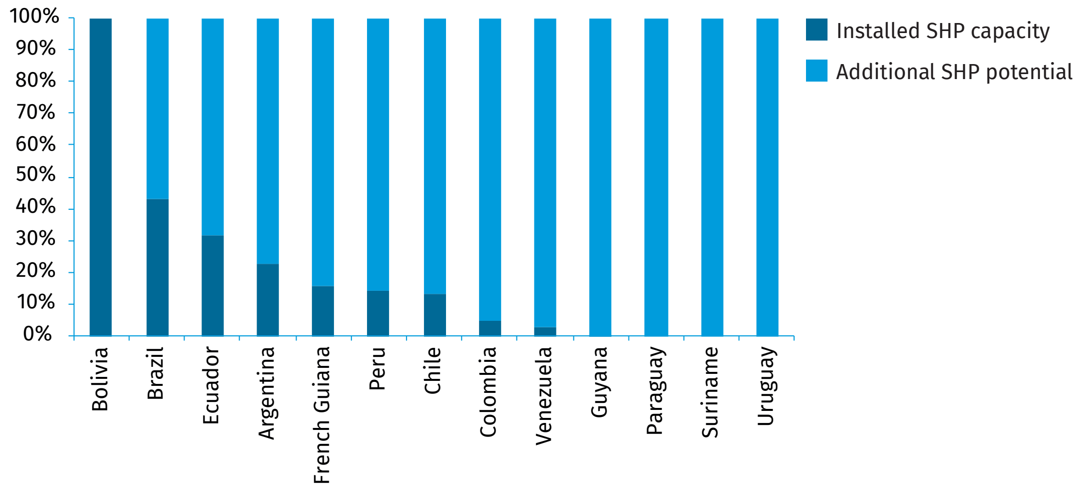
Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in South America (%)**



Source: *WSHPDR 2022*[1]

Note: Paraguay, Suriname and Uruguay are not included due to a lack of installed SHP capacity; Peru is not included due to a lack of data on SHP up to 10 MW.

Figure 2. **Utilized Small Hydropower Potential by Country in South America (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP of up to 10 MW except in the case of Paraguay and Peru, where the local definition is used due to a lack of comprehensive data on SHP of up to 10 MW.

The installed capacity of SHP of up to 10 MW in **Argentina** is 97 MW, provided by 24 plants. The potential capacity is estimated at 430 MW, indicating that nearly 23 per cent has been developed. The SHP sector in the country has not seen any recent development and many existing SHP facilities are in need of modernization. However, several SHP projects are in the planning stages and 116 potential SHP sites have been identified.

The installed capacity of SHP of up to 10 MW in **Bolivia** is 99.1 MW. There is no reliable estimate of potential for SHP off up to 10 MW, although potential for SHP of up to 30 MW has been estimated at 200 MW. There are 13 registered SHP plants in the country, in addition to dozens of unregistered plants operating on isolated grids. Unregistered off-grid SHP plants are particularly widespread in the country's private mining sector. The Government plans to expand SHP capacity by an additional 50 MW, but suitable sites have not been comprehensively catalogued. One additional SHP plant was under construction as of 2019.

In **Brazil**, the installed capacity of SHP under the local definition of up to 30 MW is 6,324.6 MW, while the estimated potential capacity is 35,765 MW, indicating that 18 per cent has been developed. For SHP of up to 10 MW, the installed capacity is 1,608.2 MW, while potential capacity is estimated at 3,737.8 MW, indicating that 43 per cent has been developed. Development of SHP in the country is actively ongoing, with over 20 new plants commissioned in 2020 alone. Construction of new plants is carried out in accordance with targets established by the Ten-Year Plan for Energy Expansion 2029. By 2029, the Government intends to expand the country's total capacity of SHP of up to 30 MW to 9,045 MW.

The installed capacity of SHP of up to 20 MW in **Chile** is 618 MW and estimated potential capacity is 5,145 MW, indicating that 12 per cent has been developed. For SHP of up to 10 MW, the installed capacity is 304 MW and estimated potential capacity is 2,995 MW, indicating that 10 per cent has been developed. SHP development in the country is ongoing, with several new plants commissioned on average every year. Several SHP projects were ongoing as of 2021 and a number of additional projects are in the planning stages.

Colombia has an installed capacity of 900.8 MW for SHP of up to 20 MW and of 234.6 MW for SHP of up to 10 MW. The potential capacity of SHP of up to 10 MW is estimated at 4,946 MW, indicating that nearly 5 per cent has been developed. A large number of new SHP plants have been commissioned in recent years, and 43 prospective SHP projects of up to 10 MW are under review. The reported estimate of the country's SHP potential has been drastically reduced on the basis of updated, more detailed data on regional SHP potential.

The installed capacity for SHP of up to 10 MW in **Ecuador** is 112.7 MW, provided by 43 plants. Potential capacity is estimated at 356.3 MW, indicating that approximately 32 per cent has been developed. Several new SHP plants were constructed in the country between 2016 and 2020, with six additional plants expected to be completed by 2024.

French Guiana has an installed capacity of 5.5 MW for SHP of up to 10 MW, provided by two plants. The estimated potential capacity, based on plans issued by the Government for expansion of the SHP sector to 2030, is 34.5 MW, indicating that 16 per cent has been developed. Despite the established targets, little SHP development has taken place in the country in recent years, although two SHP projects are in the early planning stages.

Guyana has a single micro-hydropower plant with an installed capacity of approximately 0.02 MW. Potential SHP capacity in the country for SHP of up to 10 MW is estimated at 92 MW, which remains almost fully undeveloped. The existing SHP plant was launched in 2019 and is the first operational SHP plant in the country in over 20 years. Five projects involving the rehabilitation of non-operational SHP plants as well as the construction of new plants are in various stages of planning.

Paraguay has no installed SHP capacity, as the country's entire hydropower fleet consist of plants with installed capacities of over 50 MW. The potential capacity for SHP of up to 50 MW is estimated at 116.3 MW and remains fully undeveloped. The estimate of potential capacity is based on the total planned capacity of 18 SHP projects intended to enter into operation between 2029 and 2036.

Peru has an installed capacity of 503.8 MW for SHP of up to 20 MW, while potential capacity is estimated at 3,500 MW, indicating that over 14 per cent has been developed. The country's SHP capacity has increased dramatically in recent years, and at least 11 new plants have been commissioned between 2016 and 2019. There were 24 ongoing SHP projects in Peru as of 2021, with construction to be completed by 2024.

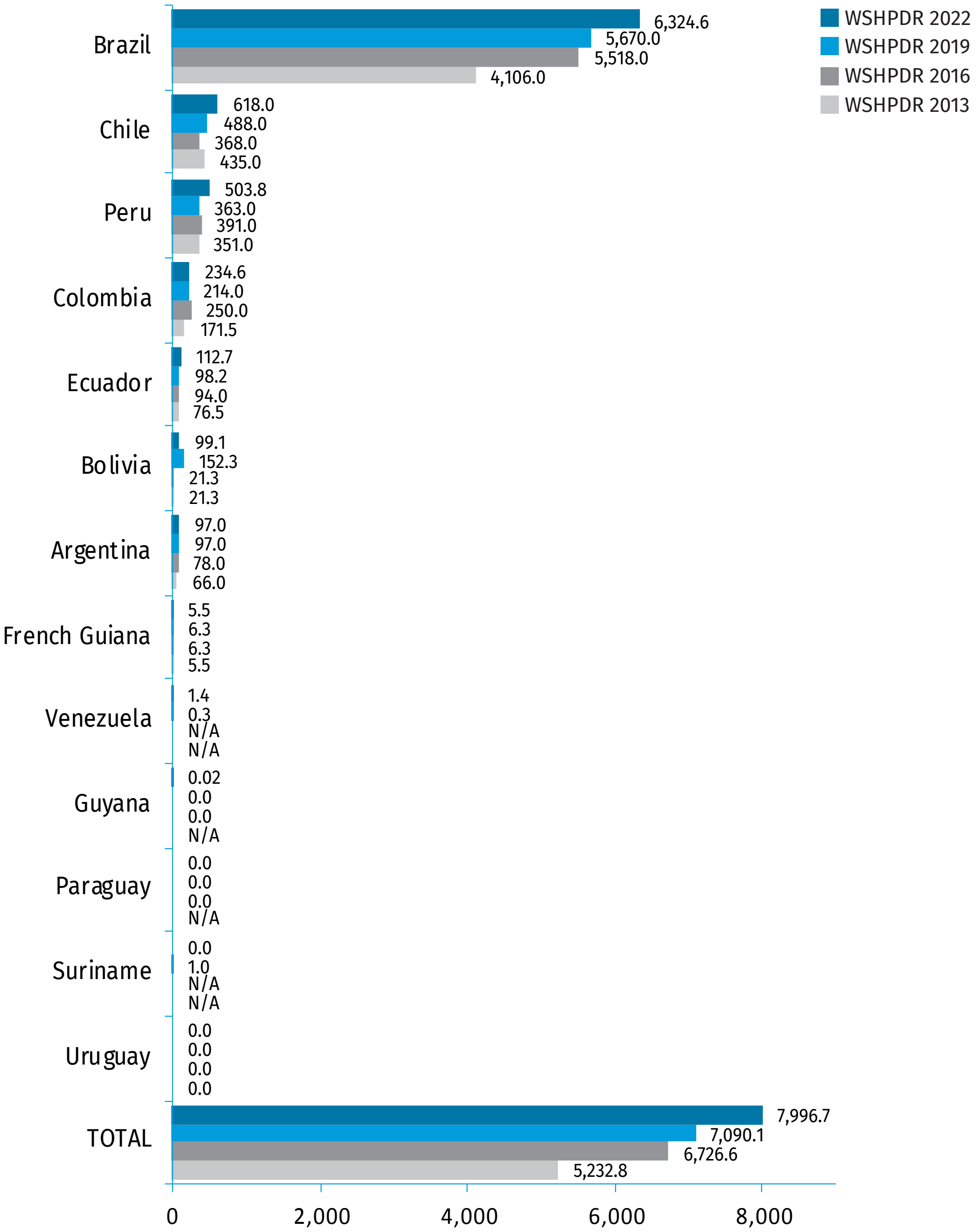
Suriname has no operational SHP capacity, although 2.7 MW of potential for SHP of up to 10 MW has been identified. Several formerly operational SHP plants exist in the country, but there are no known plans for their rehabilitation or for the construction of any new SHP plants.

Uruguay likewise has no installed SHP capacity. Potential capacity for SHP of up to 50 MW is estimated at 231.5 MW, while for SHP of up to 10 MW it is estimated at 208 MW, and remains fully undeveloped. Several studies have been carried out over the last decade assessing the technical and economic feasibility of multiple potential SHP sites, but there are no specific plans for any new SHP construction.

The installed capacity of SHP of up to 10 MW in **Venezuela** is 1.4 MW, provided by seven SHP plants, of which the most recent one was built in 1994. Potential capacity for SHP of up to 10 MW is estimated at 49.7 MW, indicating that 3 per cent has been developed. Ten potential SHP sites have been identified, but there has been little SHP development in recent years and there are no planned or ongoing SHP projects in the country.

Changes in the installed SHP capacities of the countries in the region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in South America (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

Note: For SHP of up to 10 MW except in the case of Brazil, Chile and Peru, where the local definition is used for the purpose of comparison with the previous editions of the *WSHPDR*.

Climate Change and Small Hydropower

The glacial stability of the mountainous regions in the western part of South America is affected by climate change. In the short term (the next 10 to 20 years), an initial increase in runoff could lead to a parallel increase in SHP plant capacity factors in the Andean region, but the loss of glacial cover risks making hydropower less viable in the long term by the end of the century. In the eastern part of South America, climate change projections indicate a decrease in rainfall and an increase in temperature during the peak rainfall season, combined with less precipitation during the dry season. The expected decreased runoff and an increase in seasonal flow variability threatens the viability of run-of-river hydropower projects.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Barriers to SHP development in **Argentina** include a lack of up-to-date studies of SHP potential, technical constraints on the addition of new capacities to the electricity grid and long-term impacts of climate change including the depletion of glaciers, which is expected to lead to reductions in runoff. At the same time, the country possessed a considerable undeveloped SHP capacity, an inventory of identified potential sites and a well-established SHP sector. Financing for future SHP projects is available through the country's RenovAr programme.

Bolivia has prioritized the development of large hydropower over SHP, and the country lacks a clear framework for the development of SHP projects and detailed data on potential sites. Low electricity prices in the country limit the attractiveness of SHP projects to private investors. Additionally, there has been a degree of resistance from local communities against hydropower projects. On the other hand, despite the lack of clear data, SHP potential in the country is believed to be considerable. Many rural communities could benefit from electrification delivered by off-grid SHP projects. Additionally, opportunities exist with regard to repair and refurbishment of existing plants.

Despite a very active SHP sector, obstacles to SHP development in **Brazil** include limited incentives for SHP relative to other RES, high construction and operating costs and strict environmental requirements fuelled in part by public scepticism about hydropower development in general. Overall, however, the outlook for the SHP sector in Brazil is positive as the country has extensive experience in SHP development and the sector is represented by an industry group of SHP developers. With a very significant SHP potential remaining untapped, particularly for SHP of up to 30 MW, the presence of incentives for SHP of below 5 MW and specific government targets for SHP expansion over the next decade can be expected to drive additional expansion of SHP capacities.

There are a number of factors complicating SHP development in **Chile**. These include a broad range of issues related to water use rights, lack of information and engagement with local communities on prospective and ongoing projects, unclear environmental standards and increasing water stress as a result of climate change. However, the country's undeveloped SHP potential remains one of the largest in the region. Chile has indicated its commitment to RES development and decarbonizing the economy, with SHP poised to play an important role in this process.

A major barrier to further SHP development in **Colombia** is the variability in generation from hydropower due to the effects of climate change, which is causing the country to reconsider its dependence on hydropower and prioritize the development of other RES. Additionally, institutional fragility and obstacles in negotiating with local communities and landowners can discourage investment in SHP, particularly in remote areas. The main enabler of SHP development in Colombia is the country's significant untapped SHP potential.

Similar to other countries in South America, the electricity sector development strategy of **Ecuador** has prioritized large hydropower plants over SHP. Additionally, despite the country's abundant undeveloped SHP potential, there is a lack of detailed data on technical and economic potential. At the same time, recent legislation on distributed generation and newly-proposed incentives for RES may provide a boost to SHP development in the country.

The main barrier to SHP development in **French Guiana** is significant seasonal variability of rainfall and runoff as a result of climate change, which poses a major challenge to stable hydropower generation in the country. Additional obstacles include administrative hurdles, high cost of electricity and difficulties with power transmission in remote parts of the country. Enablers of SHP development in the country include the planned partial closure of existing thermal power capacity, which is expected to act as a catalyst of RES development, as well as existing undeveloped SHP potential.

In **Guyana**, SHP development is hampered by a lack of detailed hydrological data, difficulties in providing grid connections and road access to project sites, and lack of local technical expertise. However, the rapid economic growth of Guyana over the last couple of decades, coupled with some recent momentum in the SHP sector including increased financing opportunities, may contribute to ongoing development of SHP in the country.

The main barrier to SHP development in **Paraguay** is the country's focus on large hydropower and the institutional structure underlying the current model of electricity generation in the country, which is heavily export-oriented. In addition, new policies have prioritized the development of RES other than hydropower. At the same time, the country has significant untapped SHP potential, and SHP could be employed to localize and increase the reliability of electricity supply in some areas suffering from high transmission losses.

Barriers to SHP development in **Peru** include the high initial cost of investment relative to thermal power, lack of human capacity for operation and maintenance of SHP plants, insufficient awareness among potential investor of the profitability of RES projects and issues with transportation infrastructure. Concerns over the potential environmental impact of SHP plants present an additional obstacle. Enablers include the country's extensive experience with hydropower and SHP in particular, abundant undeveloped SHP potential and several forms of support including long-term power purchase agreements, tax waivers and guaranteed purchase prices for electricity generated by SHP.

In **Suriname,** SHP development is hampered by high start-up costs, lack of funding and lack of local technical capacity in the SHP sector. The main potential driver of future SHP development in the country is the acute need of many rural settlements for stable electricity access.

The main barriers to SHP development in **Uruguay** are the country's focus on large hydropower, high costs of SHP projects relative to other RES, limited incentivization and socio-environmental restrictions. At the same time, abundant identified potential capacity and previous detailed studies of potential sites, in addition to a policy framework generally supportive of RES development, provide a solid base for future SHP development in the country.

In **Venezuela**, the main barrier to SHP development is the ongoing crisis in the electricity sector that has forced the Government to focus on large-scale projects. Additionally, data on potential sites as well as the state of existing plants is insufficient to promote development in the SHP sector. However, SHP projects could help promote decentralized generation and increase the stability of the electricity supply, particularly in the north-western part of the country, which is located farther away from existing hydropower plants and suffers from increased transmission losses.

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Argentina

Raul Pablo Karpowicz, KWZ

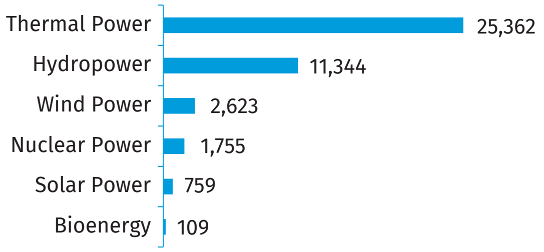
KEY FACTS

Population	45,377,000 (2020)[1]
Area	2,780,400 km^2[2]
Topography	The terrain comprises rich plains of the Pampas in the northern half, a flat to rolling plateau of Patagonia in the south and the rugged Andes along the western border. The highest point is Aconcagua, at 6,962 metres.[3]
Climate	Argentina is located within the subtropical-temperate zone. However, its extension between approximately 22° SL and 55° SL ensures great climatic diversity The north of the country has a warm and humid subtropical climate. Central Argentina has a temperate continental climate, with very hot summers and mild winters. The South has a subarctic climate and is directly influenced by the prevailing westerly winds. As the prevailing westerly winds lose their moisture and descend into Argentina, temperatures increase while humidity decreases. In the West, the Andes Mountain Range is a great determinant of the regional climate, since the high peaks from 40° SL and towards the north, together with the remoteness of the Atlantic, determine continental characteristics. January is the warmest month, while June and July are the coldest. The average annual temperatures range from 10 °C in July to up to 25 °C in January.[3,4]
Climate Change	Historically, in Argentina temperatures have risen by 0.5 °C since the beginning of the 20th century. During the latter half of the century, warming was felt in Patagonia with both maximum and minimum temperatures increasing in the region. The number and intensity of heatwaves have increased between 1960 and 2010. Precipitation has increased since the early 20th century, notably in the subtropical zones, albeit variable year-on-year. Under the most extreme climate change scenario, Argentina could see an increase of 3.5 °C by the end of the century compared to the 2014 levels.[5]
Rain Pattern	Rainfall is variable, depending on location and elevation. The north receives rain throughout the year with the annual average of approximately 750 mm. In central Argentina, the average annual rainfall varies between 1,000 mm in the east and 500 mm in the west towards the Andes. The south receives the least rainfall, with a low average of 200 mm. Towards the south, the mountain range is low and the ascent of the winds from the west produces precipitation on the Chilean side and over a narrow strip on the Argentinean side, and the winds subsequently lose their moisture by the time they reach the Patagonian plateau.[3,6]
Hydrology	The major rivers in Argentina include the Pilcomayo, Paraguay, Bermejo, Colorado, Río Negro, Salado, Uruguay and Paraná, the largest river in the country (15,000 m^3/s). The latter two flow together before meeting the Atlantic Ocean, forming the estuary of the Río de la Plata. Regionally important rivers are the Atuel and Mendoza in Mendoza province, the Chubut in Patagonia, the Río Grande in Jujuy and the San Francisco River in Salta. The provinces with the greatest small hydropower potential include San Juan, Mendoza, Rio Negro, Chubut and Santa Cruz.[3]

ELECTRICITY SECTOR OVERVIEW

At the end of 2020, the total installed capacity of Argentina was 41,952 MW.[7] The installed capacity of fossil fuel-powered thermal power plants (diesel or natural gas) was 25,362 MW. The installed capacity of hydropower amounted to 11,344 MW. Nuclear power accounted for 1,755 MW and wind power (2,623 MW), solar power (759 MW) and biomass (109 MW) made up the non-hydropower renewable sources (Figure 1).[7]

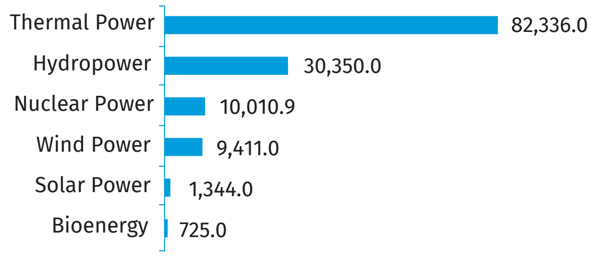
Figure 1. **Installed Electricity Capacity by Source in Argentina in 2020 (MW)**



Source: CAMMESA[7]

Total electricity generation in 2020, discounting imports, was 134,177 GWh (135,381 GWh including imports). The contribution of small hydropower SHP (below 50 MW) amounted to 1,257 GWh, whereas large hydropower contributed 29,093 GWh, totalling 30,350 GWh. Non-hydropower generation came from thermal power (82,336 GWh), nuclear power (10,011 GWh), solar power (1,344 GWh), wind power (9,411 GWh) and bioenergy (725 GWh) (Figure 2).[7]

Figure 2. **Annual Electricity Generation by Source in Argentina in 2020 (GWh)**



Source: CAMMESA[7]

During the last 15 years the share of hydropower in the total installed capacity of Argentina has decreased, mainly because thermal power, wind power and solar photovoltaic (PV) power are less time-intensive from project conception to operation. The decreasing international equipment prices in solar PV and excellent wind capacity factors in the Patagonia as well as promotion of renewable energy have supported this tendency. Moreover, construction of large hydropower plants in Argentina is complicated due to an unstable economic situation in the country and environmental concerns. Theoretically, the country has enough water resources to generate approximately 170,000 GWh annually.[7] However, so far it barely produces 20–25 per cent of that energy volume.[8]

Transactions between the different participants in the electricity industry are carried out through the Wholesale Electricity Market (WEM) controlled by the Wholesale Electricity Market Management Company (Compañía Administradora del Mercado Mayorista Eléctrico, CAMMESA), the administrator of the electricity market. The WEM is organized as a competitive market in which generators, distributors and certain large electricity users can buy and sell electricity at prices determined by supply and demand; others are allowed to enter into long-term electricity supply contracts. The WEM consists of:

- A term market where the quantities, prices and contractual conditions are agreed on directly between sellers and buyers according to specific resolutions, such as the "Term Market for Renewable Energies" (MAT ER), established by Resolution No. 281/2017 of the former Ministry of Energy and Mining;
- A spot market, where prices are established per hour based on the economic cost of production;
- A stabilized system of spot prices through seasonal prices, established every six months and designed to mitigate the volatility of spot prices for the purchase of electricity by distributors.[9]

The electricity is transported through the SADI (Argentina Interconnected System). There are public and private companies involved in the generation, transport and distribution of energy. Pampa Energía is one of the fast-growing private companies that is heavily involved in the renewable energy arena.[10] The National Electricity Regulatory Commission (ENRE) is an independent entity within the State Secretariat for Energy and is responsible for regulating the energy industry.

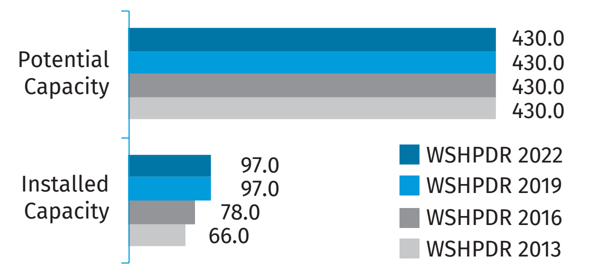
The large interconnection networks allow the transportation of energy flows at a regulated cost. However, transmission lines at medium and high voltage are not enough to satisfy new generation. This is a structural deficit to be overcome, as larger energy projects are unable to connect due to these transmission grid capacity constraints. Nonetheless, the country has had 100 per cent electrification since 2017.

Public electricity tariffs are regulated by the Government. As of March 2021, the household prices were 0.058 USD/kWh, while business prices were 0.039 USD/kWh.[11] Prices were frozen in 2019 following a period of high inflation that drastically impeded the country's economic growth and reduced consumer spending power. More recently in May 2019, the regulator announced that distribution firms Edenor and Edesur would introduce a 9 per cent tariff increase around the city of Buenos Aires to guarantee continuity in provision, with immediate effect.[12]

SMALL HYDROPOWER SECTOR OVERVIEW

In Argentina, SHP is classified as hydropower plants with an installed capacity of less than 50 MW. For the purposes of comparison with the previous editions of the *World Small Hydropower Development Report* (*WSHPDR*), the 10 MW definition will be used in this chapter. The current installed capacity of SHP plants of under 10 MW is 97 MW from 24 plants, thus there is no change from the *WSHPDR 2019* capacity levels (Figure 3, Table 1).[7] There are 43 SHP plants of a capacity of less than 50 MW, with a total of 510 MW of installed capacity.[6] There is no updated information on overall potential capacity since the previous editions of the *WSHPDR*.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Argentina (MW)**



Source: CAMMESA,[7] *WSHPDR 2013*,[13] *WSHPDR 2016*,[14] *WSHPDR 2019*[15]

Note: Data for SHP up to 10 MW.

There is a great potential for SHP in Argentina. A national inventory of SHP facilities was conducted by the former Ministry of Energy and Mining has identified 116 potential projects, at different levels of development (see Table 3).[16] A plan for the dissemination of SHP has been proposed. Firstly, it will be necessary to conduct thorough impact studies of the hydrological, geological, geotechnical and environmental situation. Few studies have been conducted so far and there are numerous plants and facilities which require modernization. Secondly, it is also recommended to evaluate additional environmental benefits, the social cost of externalities as well as the supply of drinking water with the aim of including them in remuneration for potential investors and companies interested. In addition, ensuring that all provinces of Argentina accept and implement the distributed generation law may further enhance the development of SHP in the country.

Table 1. **List of Selected Operational Small Hydropower Plants in Argentina**

Name	*Location*	*Capacity (MW)*	*Operator*
CACVHI	Cuyo	9	CONSORCIO POTRERILLOS
SANDHI	Comahue	7.9	CENTRAL SALTO ANDERSEN
RESCHI	Comahue	7.2	PAH RIO ESCONDIDO-PATAG
RREYHI	Noa	7	HIDROELECTRICA REYES EJSEDSA
COROHI	Cuyo	6.64	GENERADORA ELECTRICA MENDOZ.SA
SMARHI	Cuyo	6.48	GENERADORA ELECTRICA MENDOZ.SA
LUNLHI	Cuyo	6.34	PAH LUNLUNTA - EMESA
PMORHI	Centro	6.3	EPEC GENERACION
ROMEHI	Comahue	6.2	CENTRAL JULIAN ROMERO 5 SALTOS
CIPOHI	Comahue	5.4	CENTRAL HIDRAULICA CIPOLLETTI
CESPHI	Comahue	5.2	CENTRAL HIDRAULICA CESPEDES
LMO2HI	Centro	4.5	EPEC GENERACION
CALEHI	Centro	4.4	EPEC GENERACION
GROCHI	Comahue	2	EMP DE ENERGIA DE RIO NEGRO SA
LQUIHI	Noa	2	HIDROELECTRICA RIO HONDO SA
LUJAHI	Cuyo	1.7	PAH LA LUJANITA - ENARSA
TBENHI	Cuyo	1.7	PAH DIQUE TIBURCIO BENEGAS
GUA6HI	Cuyo	1.2	PAH CAN.CQUE GUAYMALLEN SALTO6
GUA7HI	Cuyo	1.2	PAH CALBUCO SALTO7
GUA8HI	Cuyo	1.2	PAH CAN.CQUE GUAYMALLEN SALTO8

Source: CAMMESA[7]

Western areas of the country are very attractive for SHP development. Wind power is growing very fast because of the high-capacity factors in Patagonia (south of the country); however, the transmission lines capacity remains a limiting factor. Solar PV plants are being developed mainly in the north (Jujuy province). Several SHP projects are in planning at various stages (Table 2). However, the planning timelines have been drawn out over several years and the current status of these projects is difficult to determine. Table 3 presents a list of projects available for investment.

Table 2. **List of Selected Planned Small Hydropower Projects in Argentina**

Name	*Location*	*Capacity (MW)*
Corpus	Misiones, international with Paraguay	3.8
Patí o Machuca Cué	Corrientes – Santa Fe	2.9
Chapetón	Entre Ríos – Santa Fe	2.3
Garabí	Corrientes, international with Brazil	1.6
Cordón del Plata	Mendoza	1.5

Source: Hydro Review,[17] Bnamericas,[18] Water Power Magazine[19]

Table 3. **Small Hydropower Projects Available for Investment in Argentina**

Name	*Location*	*Potential capacity (MW)*
La Quebrada	Lules River, Tucumán	5.6
Luján de Cuyo	Mendoza River, Mendoza	1.1
San Martín de los Andes	Chapelco River, Neuquén	0.4
Caviahue	Agrio River, Neuquén	0.4
Andalgalá	Andalgalá River, Catamarca	0.4

Source: Ministry of Economy, Energy Secretariat[16]

RENEWABLE ENERGY POLICY

By October 2015, Law No 27.191 was enacted (regulated by the necessity and urgency Decree No. 531/16), modifying Law No 26.190 to promote the use of renewable energy sources.[20,21] Among other measures, it was established that by 31 December 2025, 20 per cent of the total energy demand in Argentina must be covered with renewable energy sources. To achieve this objective, the GUs (large users) of the WEM and CAMMESA must cover 8 per cent of their demand with renewable sources as of 31 December 2017. This percentage is to be increased every two years until reaching the aforementioned objective. The contracts entered with GUs and GUDIs (large distribution users) cannot have an average price exceeding 113 USD/MWh.

Resolution No. 281/17 of the MEyM (former Ministry of Energy and Mining) issued in 2017 regulates the Term Market of Renewable Energies (MAT ER) regime. The resolution established the conditions for GUs of the WEM (Wholesale Electricity Market) and GUDIs to follow in relation to their obligation to meet their demand through renewable sources, whether through individual contracting in the MAT ER or by self-generation. Likewise, the conditions that generation projects must meet are regulated. In particular, the RENPER (Registry of Electric Power Generation Projects from Renewable Source) was created, in which such projects must be registered.[22]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Currently, the legal umbrella for SHP is Law No. 27.191, which modifies Law No. 26.190 to promote the use of renewable energy sources.[23] CAMMESA controls the transactions of energy based on conditions or regulations, such as the contracts awarded in the RenovAr programme and contracts in the MAT EW market. Water use rights and permits, including environmental permits, are the jurisdiction of provinces. SHP plants whose energy production is not transported by the interconnected system are regulated by the provinces in accordance with the national laws. The Regulatory National Dam Safety Argentinian Authority (ORSEP) is the national entity responsible for regulating the safety dams in the country, including those used for hydropower generation.

The Ministry of Economy Energy Secretariat has a directorate directly involved in the promotion of SHP in the country, the National Directorate for Promotion (DNPROM). The objectives of the DNPROM include:

- Surveying the facilities in operation and out of service as well as those suitable for refurbishment and of public irrigation structures that can be equipped with generating units;
- Compilation, review and proposal of reformulating the provincial legal regimes of water, environment and energy, in agreement and collaboration with governments and provincial agencies;
- Analysis of the profitability of SHP in isolated markets, development of case studies and a roadmap of projects related (or not) to the Clean Development Mechanism;
- Identification and management of public and private financing lines for the execution of the technical and economically feasible works.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

SHP is promoted by the Government's programme RenovAr, which called for bidders interested in investing, who then receive a payback from sales of energy during a period of up to 20 years. The RenovAr programme is controlled by the Ministry of Economy Energy Secretariat and promotes actions aiming to encourage large-scale investments in renewable energy projects. The RenovAr was launched in different stages, officially named rounds: Round 1, Round 1.5 and Round 2. The differences between these stages were the modifications in the available quotas for the different types of renewable sources and the adjustments of the referential prices. Referential prices depend on the energy source — wind power, solar PV, biomass or hydropower. The latest prices awarded during the second round were between 89 USD/MWh and 105 USD/MWh.[24] Nine projects were awarded in round 2, representing a total capacity of 21 MW (Table 4).[23]

Table 4. **Small Hydropower Plants awarded under RenovAr Round 2**

ID	*Name*	*Location*	*Potential capacity (MW)*	*Applicant*
PAH-709	P.A.H. Boca del Rio	Centro, Córdoba	0.5	EPEC
PAH-708	P.A.H. Cruz del Eje	Centro, Córdoba	0.5	EPEC
PAH-710	P.A.H. Pichanas	Centro, Córdoba	0.5	EPEC
PAH-700	P.A.H. Las Tunas	Cuyo, Mendoza	10.0	CONSTRUCCIONES ELECTROMECÁNICAS DEL OESTE S.A.
PAH-702	P.A.H. Salto 7	Cuyo, Mendoza	1.2	CONSTRUCCIONES ELECTROMECÁNICAS DEL OESTE S.A.
PAH-712	P.A.H. Lunlunta	Cuyo, Mendoza	6.3	NEXO ENERGIA S.A.
PAH-715	P.A.H. Salto 11	Cuyo, Mendoza	0.5	SKRU S.A.
PAH-714	P.A.H. Salto 40	Cuyo, Mendoza	0.5	SKRU S.A.
PAH-705	P.A.H. Salto De La Loma	Cuyo, San Juan	0.7	LATINOAMERICANA DE ENERGÍA S.A.

Source: Ministry of Economy, Energy Secretariat[23]

Additionally, renewable energy projects can benefit from various incentives, including tax benefits (early VAT refund, accelerated amortization of income tax, exemptions from import duties, etc.), and the constitution of the Fund for the Development of Energy Renewables (FODER), which is destined, among other objectives, to grant loans, capital contributions, etc. to contribute to the financing of such projects.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

As a result of climate change, the Paraguay, Uruguay and Paraná Rivers have seen an increase in their mean flows as well as the frequency of extreme discharge events.[4] The glacial stability of the Andes Mountains is also affected by climate change as glacial melt puts at risk the balance of water provision for hydropower dams. The initial increase in runoff could increase plant capacity factors but make hydropower business models less viable in the long term.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Argentina has great SHP potential. Overall, hydropower is considered as an available and economical technology for national development in the long term, which, if appropriately planned, can serve multiple purposes, including tourism, water supply, flood control, irrigation, local development, etc. However, several barriers hinder further development of the SHP technology in the country, including the following:

- Extensive studies involving multiple jurisdictions with corresponding permits and environmental concerns delaying new projects;
- Slow development of the sector in recent years;
- Electricity grid constraints limiting new capacity additions;
- Long-term detrimental effects of climate change due to the depletion of glacial water resources;
- Limited information on potential capacity and sites.

The following points summarize the main enabling factors for further SHP development in the country that have been identified:

- A decent baseline of operational SHP projects as evidence of the viability of the technology in Argentina;
- An inventory of potential sites for development is available, albeit missing capacity-specific information;
- Potential short-term increase in plant capacity due to climate change effects and glacial melt;
- Availability of financing from the national RenovAr programme.

In this context, it appears critical to create new specific legal incentives that could facilitate SHP development, considering all its benefits that other renewable energy technologies cannot offer. Public-private solutions or refurbishment of old power plants could offer key opportunities for the development of the SHP sector.

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Bolivia (Plurinational State of)

Cleber Romao Grisi, WHITEnergy Bolivia

KEY FACTS

Population	11,673,029 (est. 2020)[1]
Area	1,098,581 km^2 [2]
Topography	Bolivia is a landlocked country with geographic zones featuring great variations in altitude.[1,3,4] The Andean zone lies in the west of the country and covers approximately 28 per cent of the national territory. It is a mountainous zone formed by the Occidental, the Oriental, the Royal, the Cordillera Central and the Altiplano. The highest point is the Sahama peak at 6,542 metres; the average altitude in the Andean region is between 3,750 and 4,000 metres.[1,3,4] The Sub-Andean zone, commonly known as the Yungas and the Valles, consists of valleys of varying altitudes, with an average of 2,500 metres. The Eastern Plains, known as the Llanos, cover the tropical savannahs, the Amazonian forest, agricultural lands and the desert region of El Chaco. This zone occupies almost two-thirds of the national territory. The region has an average altitude of 400 metres and a minimum altitude of 90 metres at the Paraguay River.[1,3,4]
Climate	The Andean zone has a desert polar climate, with strong, cold winds and high solar radiation; temperatures range between a minimum of below 0 °C and a maximum of 20 °C. The Sub-Andean zone features a very humid and rainy climate, with the average temperature ranging between 15 °C and 25 °C. Finally, the average temperature in the Eastern Plains is approximately 30 °C.[1,3]
Climate Change	Since the year 2000, the country's average temperature has increased by 0.1 °C. It is expected that the average temperature will rise by 3.6–5.1 °C by the year 2100. The major effects of the rising average temperatures in Bolivia include the disappearance of glaciers on mountaintops (for example, the Chacaltaya Peak), a decrease in rainfall, a reduction of average humidity, an increase in the duration of periodic droughts, changes in the rainfall pattern and the increasing severity of flood events.[5,6,7]
Rain pattern	Bolivia has a tropical climate with average precipitation of 640 mm per year. The rainy season lasts from mid-October to March.[8,9] Rain is much more pronounced in the Sub-Andean zone and the Eastern Plains. Precipitation patterns in these zones vary from 2,000 mm per year in the north to 600 mm per year in the south. Precipitation is highest in the valleys, reaching up to 6,000 mm per year.[3,9] In the Andean zone, particularly on the Altiplano, it rains much less. Precipitation can be as low as 200 mm per year, except in the area surrounding the Titicaca Lake basin where precipitation can reach up to 1,000 mm per year.[3,9]
Hydrology	The most important rivers of Bolivia start in the Andes Mountains and descend across the valleys into the eastern tropical lands. The three main watersheds and river systems are: 1) the Amazon basin, which runs from the east to the west, composed mainly of the Madre de Dios, Orthon, Abuná, Beni, Yata, Mamore and Iténez (or Guaporé) Rivers. The Guaporé, the Mamoré, the Beni and the Madre de Dios cross the often-flooded northern savannah and tropical forests, all converging in the north-east to form the Madera River flowing into Brazil. 2) The Central or Lake basin, formed by Titicaca and Poopó Lakes, the Desaguadero River and large salt lakes Coipasa and Uyuni. Titicaca Lake is 222 km long and 113 km wide; with its surface at an altitude of 3,805 metres, it is the highest navigable lake in the world. The lake is drained to the south by the Desaguadero River, which empties into Poopó Lake. 3) The South or the La Plata River basin is composed mainly of the Paraguay, Pilcomayo and Bermejo Rivers, which cross the Chaco region to the south-east as they leave Bolivia to form the border between Paraguay and Argentina.[3,4]

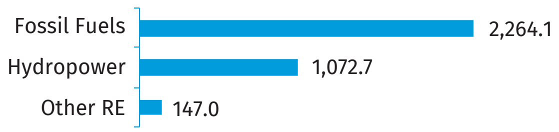
ELECTRICITY SECTOR OVERVIEW

The electricity sector of Bolivia includes the national grid, known as the National Interconnected System (SIN), several isolated networks, the wholesale market, the end consumers and the electricity authorities.[10,11]

In 2019, the total installed capacity in Bolivia was 3,483.8 MW and the total electricity generation amounted to 10,699.4 GWh, of which 89 per cent was supplied to the SIN and 11 per cent to the isolated networks.[10,12,13,14] The SIN covers the entire country except for the territory of Pando in the north.[10] In 2019, the total installed capacity of the SIN stood at 3,150.1 MW and electricity generation totalled 9,530.8 GWh. The maximum registered power demand of the end consumers amounted to 1,512.3 MW and the total electricity demand reached 9,242.2 GWh. The energy demand grew by 22 per cent relative to 2016 and by 3 per cent relative to 2018. There were 5,860.5 km of transmission lines, including 3,754.1 km at 230 kV, 1,892.2 km at 115 kV and 214.2 km at 69 kV.[10]

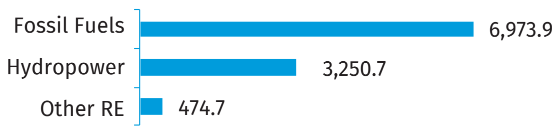
The major share of electricity in Bolivia in 2019 was produced by non-renewable thermal sources, mainly natural gas combustion and some diesel turbines, with an installed capacity of 2,264.1 MW (65 per cent of the total) and an annual generation of 6,973.9 GWh (65 per cent of the total), followed by hydropower with an installed capacity of 1,072.7 MW (31 per cent) and an annual generation of 3,250.7 GWh (30 per cent) and other renewable energy sources, including wind power, biomass and solar power, in total representing 147 MW of installed capacity (4 per cent) and a total annual generation of 474.7 GWh (4 per cent).[10] Figures 1 and 2 show the 2019 installed capacity and electricity generation, respectively, in Bolivia by source.

Figure 1. **Installed Electricity Capacity by Source in Bolivia in 2019 (MW)**



Source: CNDC,[10] AE[14]

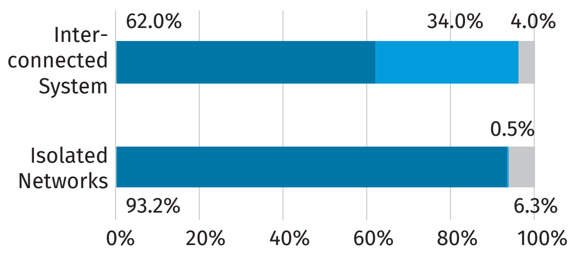
Figure 2. **Annual Electricity Generation by Source in Bolivia in 2019 (GWh)**



Source: CNDC,[10] AE[14]

In 2019, there were a total of 25 registered isolated networks in Bolivia. This represents a decrease from the number cited in the *World Small Hydropower Development Report (WSHPDR) 2019* (38 networks), which is due to the merging of some of the previously isolated networks with each other or with the national grid. Registered isolated networks use a combination of hydropower, solar power, biomass and thermal power (gas and diesel) as energy sources (Figure 3). These networks produced a total of 702.67 GWh of electricity in 2019.[14] Apart from the registered isolated networks, there are also non-registered isolated networks in many parts of the country. There is a lack of up-to-date and accurate data related to these non-registered networks; however, their combined installed capacity is estimated at 27.5 MW.[12,13,15]

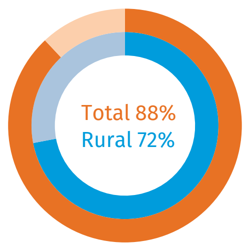
Figure 3. **Share of Installed Capacity of Electricity Networks by Energy Source in Bolivia in 2019 (%)**



Source: CNDC,[10] AE[14]

In 2019, the estimated rate of access of the population to electricity in Bolivia was 88 per cent, with urban coverage at 99 per cent and rural at 72 per cent (Figure 4).

Figure 4. **Electrification Rate in Bolivia in 2019 (%)**



Source: Ministry of Hydrocarbons and Energy[16]

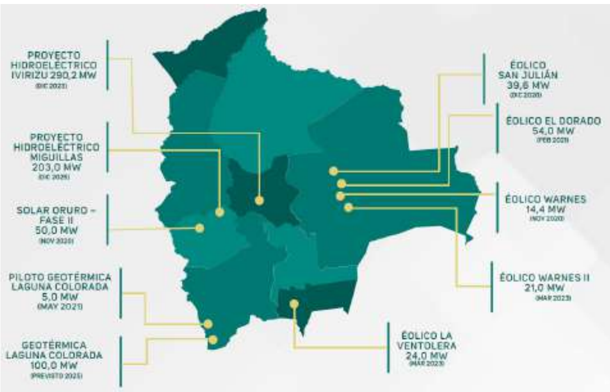
The government authorities and institutions that regulate the Bolivian electricity sector are the Ministry of Hydrocarbons and Energy, through its two vice ministries — Vice Ministry of Electricity and Alternative Energies and Vice Ministry of Energy High Technologies; the regulation and control authority, the Electricity and Nuclear Technology Supervision Authority (AE); the interconnected system administration, control and operation entity, the National Committee for Cargo Dispatch (CNDC); and the state-owned National Electricity Company (ENDE).[10,11,16]

Both public and private companies participate in electricity generation, transmission and distribution in Bolivia. The largest stakeholder is the state-owned corporation ENDE, which owns most of the generation facilities, transmission and distribution utilities across the country. In addition, ENDE is responsible for planning the growth of the electricity market and for the development of energy projects.[10,11,14,16]

In 2014, the Government issued a plan for the expansion of the electricity sector, which estimated that by 2022 electricity demand would reach 14,336 GWh/year, requiring a total installed capacity of 2,297 MW.[17] Approximately 53 per cent of this future demand was intended to be fulfilled by hydropower.[17] The current installed capacity of Bolivia has, thus, already surpassed the goal established in 2014 by a wide margin; however, demand and generation both remain below the established target.

Following the mandate of the country's constitution and electricity expansion plan, the Government of Bolivia has been developing the electricity sector by increasing the installed capacity, merging isolated networks with the national grid and expanding the transmission and distribution lines to increase access to electricity.[10,11,14,16] From 2014 to 2019, the installed capacity of the national grid increased from 1,695.8 MW to 3,150.1 MW, indicating a growth of 86 per cent. However, electricity generation during the same period increased by only 22 per cent, from 7,836.5 GWh in 2014 to 9,530.8 GWh in 2019.[10] Between 2014 and 2019, the following generation projects were completed: Misicuni hydropower plant (120 MW), San José hydropower plant I (55 MW) and II (69 MW), Oruro Phase 1 solar power plant (50 MW), Uyuni solar power plant (60.1 MW), Yunchará solar power plant (5 MW), Termoeléctrica del Sur thermal combined cycle plant (263.2 MW), Warnes thermal combined cycle plant (269.2 MW), Entre Ríos thermal combined cycle plant (272.8 MW), expansion of the Unagro biomass plant (14.2 MW) and the Aguaí biomass plant (6 MW). Additionally, a number of merged isolated networks supplied by diesel generators contributed to the SIN capacity expansion with a total of 5.4 MW.[16] As of early 2021, there were 10 renewable energy projects under construction as part of the SIN expansion, of which 493 MW belonged to hydropower, 50 MW to solar power, 105 MW to geothermal power and 153 MW to wind power sources distributed throughout the country (Figure 5).[16]

Figure 5. **Energy Projects under Construction in Bolivia**

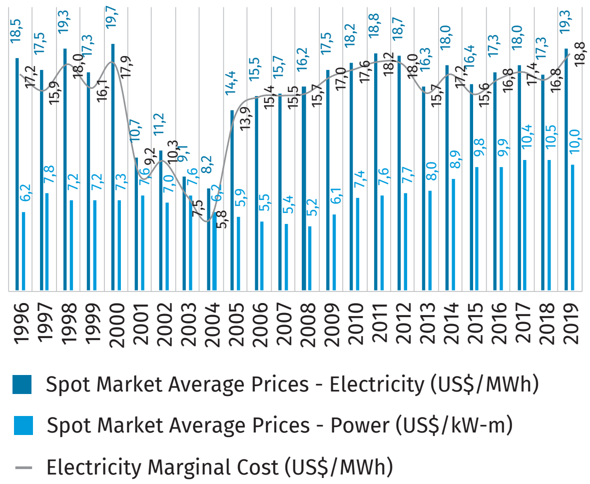


Source: Ministry of Hydrocarbons and Energy[16]

also responsible for the operation, safety and optimization of the national grid.[10,11,14]

For the commercial transactions in the SIN, on the spot market, the electricity sales are paid by the sum of two figures: the electricity produced and the power availability. The electricity sales price is a function of the generation marginal cost. This represents the electricity cost of the last unit required to generate the next kWh demanded by the system, affected by a factor that considers the losses at the node, where the electricity is delivered to the grid. The power availability price is the calculated cost related to the estimated investment and the fixed operation cost required to supply the demand plus a reserve in the long term to guarantee the supply of the future electricity demand.[10] In 2019, the average electricity marginal cost in the spot market was 18.84 USD/MWh and the corresponding average electricity sales price was 19.33 USD/MWh. The average power availability price per month was 10.0 USD/kW. Figure 6 shows the variation of electricity and power availability prices in the spot market since 1996.[10]

Figure 6. **Spot Market Marginal Cost and Sales Prices in Bolivia in 1996–2019**



Source: CNDC[10]

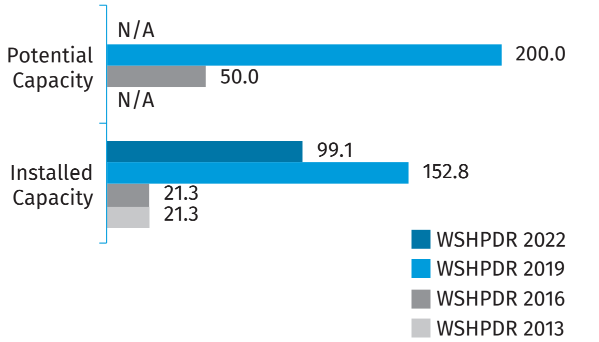
Despite fossil fuels being the predominant energy source, the electricity tariffs in Bolivia are among the lowest in South America. This is due to the subsidized gas and diesel prices for electricity production. The end users are classified into two groups: non-regulated and regulated consumers. If the demand of a single end user exceeds 1 MW, then the consumer belongs to the non-regulated group. Those in the non-regulated group can participate in the spot market as well as make power purchase agreements (PPA), which are to be first authorized by the competent authority. End users with a demand below 1 MW belong to the regulated group and their demand is attended to by the local electricity distribution utilities. The electricity transactions are held in the wholesale spot market administered by the CNDC, which is

SMALL HYDROPOWER SECTOR OVERVIEW AND POTENTIAL

The definition of small hydropower (SHP) in Bolivia is up to 5 MW; however, for the purposes of this Report, the standard definition of up to 10 MW will be used. Approximately 9 per cent of the electricity produced to supply the SIN comes from SHP plants (< 10 MW). These facilities belong to both private and public (ENDE) companies.[10]

In 2019, the installed capacity of SHP in Bolivia was 99.1 MW. Of this total, 12 plants with a total of 25 operational units and a combined capacity of 69.2 MW were connected to the national grid and one registered SHP plant of 1.2 MW capacity (Yocalla) was operating on an isolated network (Table 1).[14] The estimated electricity generation of the SHP plants connected to the national grid was 780.3 GWh in 2019.[10] Compared to the *WSHPDR 2019*, the installed capacity reported for SHP plants in Bolivia is lower by 53.7 MW (approximately 35 per cent) due to an earlier inclusion of hydropower plants with an installed capacity of below 30 MW and above the applicable SHP definition of up to 10 MW; which has been corrected for the current report. There is no reliable estimate of potential capacity for SHP as no specific studies related to SHP potential up to 10 MW are available; however, an overall potential capacity of approximately 200 MW for hydropower projects below 30 MW is estimated, which includes all currently installed hydropower plants of below 30 MW capacity (Figure 7).

Figure 7. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Bolivia (MW)**



Source: *WSHPDR 2013*,[18] *WSHPDR 2016*,[19] *WSHPDR 2019*,[20] CNDC,[10] Ministry of Hydrocarbons and Energy[17]

Note: Data for SHP up to 10 MW.

Table 1. **List of Registered SHP Plants in Bolivia**

Name	*Location*	*Capacity (MW)*	*Turbine type*	*Type of plant*	*Operator*
Tiquimani	La Paz	9.7	Pelton	Run-of-river	COBBE (Private)
San Jacinto	Tarija	7.6	Pelton	Run-of-river	ENDE (Government)
Kanata	Cochabamba	7.5	Pelton	Run-of-river	SYNERGIA (Private)
Santa Rosa BC	La Paz	6.9	Francis	Run-of-river	COBBE (Private)
Botijlaca	La Paz	6.8	Pelton	Run-of-river	COBBE (Private)
Angostura	La Paz	6.2	Pelton	Run-of-river	COBBE (Private)
Choquetanga	La Paz	6.2	Pelton	Run-of-river	COBBE (Private)
Carabuco	La Paz	6.1	Pelton	Run-of-river	COBBE (Private)
Landara	Potosí	5.2	Pelton	Run-of-river	ENDE (Government)
Miguillas	La Paz	2.6	Pelton	Run-of-river	COBBE (Private)
Punutuma	Potosí	2.4	Pelton	Run-of-river	ENDE (Government)
Quehata	Oruro	2.0	Pelton	Run-of-river	ENDE (Government)
Yocalla*	Potosí	1.2	Pelton	Run-of-river	Sinchi Wayra S.A. (Private)

Source: CNDC,[10] AE[14]

Note: Yocalla SHP plant located on isolated network; data on turbine type and plant type unconfirmed.

In addition to the officially registered SHP plants, there are SHP plants providing energy to non-registered isolated networks such as small villages or industrial sites (for example, mines). Some of these plants were constructed during the development of the mining industry back in the 19th century and many others were installed within the past 40 years to meet the demand of local communities. As of 2019, there were 68 identified SHP plants on non-registered isolated networks throughout the country with an estimated total installed capacity of 28.7 MW; however, precise data on these plants is difficult to provide.[12,13,15] Most of the identified power plants are out of service or in poor condition and could be eligible for refurbishment.

Bolivia has the potential to develop 39.9 GW of hydropower capacity. The most suitable region is the Amazon basin with a potential capacity of 34.2 GW, followed by the Plata River basin with 5.4 GW and the Andean basin (Altiplano) with 0.3 GW.[10,17,21,22] SHP potential in Bolivia has been estimated for projects of up to 30 MW capacity, as part of the Government's strategic plan for the development of alternative energy sources presented in 2014. The strategic plan includes the development of micro- (<500 kW), small- (500 kW–5 MW) and medium-scale (5–30 MW) hydropower projects.[23] The plan provides for approximately 30 MW of total hydropower capacity for grid connection and another 20 MW for isolated networks to be funded through both public and private investment.[23] Identification of potential sites to fulfil these targets is required.

As of 2019, construction of the El Cóndor SHP plant is in progress. This project has an estimated capacity of 1.47 MW and an average targeted annual generation of 9.85 GWh (Table 2). The project is funded by the Government and implemented by the state-owned company ENDE Valle Hermoso. The construction works started in 2019.[24]

Table 2. **Planned SHP Project in Bolivia**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Turbine type*	*Plant type*	*Developer*	*Planned launch year*	*Development stage*
El Cóndor	Potosí	1.47	56.58	Pelton	Reservoir	Ende Valle Hermoso	N/A	Construction

Source: ENDE Valle Hermoso[24]

RENEWABLE ENERGY POLICY

The Government has set the goal to change the country's energy mix, as of today dominated by gas units, to renewable energy sources, principally hydropower. An important reason to encourage hydropower projects is the country's enormous hydropower potential. The shift to renewable energy will also reduce natural gas use in local energy production and allow more natural gas to be instead exported to Brazil and Argentina. The export price for Bolivian gas is about seven times higher than the price established for the local market, which has been subsidized for electricity production.[10,11,17]

In 2014, the Government published the new Investment Promotion Law as well as Supreme Decree No. 2048 for remuneration of renewable energy projects and the promotion of investments in the electricity sector, in particular, hydropower, wind power, geothermal and solar power projects.[25] Therefore, today the political scene in Bolivia is becoming more suitable and attractive for both foreign and local investments in the electricity sector.[23]

Renewable energy projects, including run-of-river hydropower plants, will not be remunerated according to the actual electricity tariff system, which considers a combined payment for electricity produced and the capacity of available power. These projects will be paid for by energy production as stated in Supreme Decree No. 2048 of 2014.[25]

The energy tariffs for new projects are not defined yet, nor are financial mechanisms; regulations and investment frameworks are in the process of being implemented. Each project will have to negotiate and establish the electricity price through a purchase agreement according to the requirements of ENDE, the interests of the investor and the authorizations of AE. Some benefits offered to SHP projects may include:

- Exemption from taxes for importing equipment and construction;
- Subsidies coming from the Government's renewable energy fund;
- Guaranteed price from a mid- or long-term purchase agreement ensuring generation costs to be covered and an acceptable investment return rate;
- Stable tributary conditions for 10 years;
- Possibility to defer the aggregated value tax payment for five years from the beginning of the commercial operation date; and
- Some other benefits, including the exemption from paying the transmission and the grid administrator (CNDC) fees.[23]

The Government is also working on additional structures and rules to finance SHP and other renewable energy developments, such as by assigning incentives to local (department level) authorities for projects with an installed capacity of up to 2 MW and to municipalities or to indigenous authorities for projects with an installed capacity of up to 1 MW.[23]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

According to the studies performed since 2000, climate change in Bolivia is affected by El Niño and La Niña phenomena and CO_2 emissions, and has caused an increase in the average temperature of 0.1 °C, a decrease in rainfall and a reduction of average humidity.[6,7,25]

One of the major impacts of the climate crisis in Bolivia, with direct relevance to hydropower, is the retreat of glaciers. Over the past 40 years, more than 50 per cent of the country's glaciers have disappeared. This may result in a decrease in glacial meltwater feeding into streams and aquifers, particularly in the Andean region, implying that streams will depend more on rainfall. Rainfall has a linear relationship with stream flows, thus, the variation in rainfall will have the same effects in river streams.[5,6,7] As rainfall has also been decreasing and is expected to decrease further, studies predict that hydropower generation may reduce by 18–20 per cent by the year 2100.[7]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Bolivia is a country with potential for SHP development. There are many identified sites suitable for SHP facilities as well as existing plants in need of refurbishment.

The main challenges for SHP development in Bolivia are, but not limited to:

- Government priority and policies are to develop large hydropower to export electricity to neighbouring countries;
- Renewable energy development framework, rules and conditions have not been established yet;
- The low electricity prices are not very attractive for private investments;
- Poor quality of hydrological, climate and other statistical data required for hydropower studies, especially for rural areas;
- Complications associated with the establishment of a private company or development of a private hydropower project in terms of prices, competition and

public acceptance;
- Social situation in Bolivia, including roadblocks and protests, can interfere with project development, construction and further operations;
- Projects can be cancelled due to social resistance;
- Bureaucratic procedures, authorizations and paperwork to comply with the requirements often take longer than expected.

Some enabling factors for SHP development in Bolivia include:
- A hydrological and topographic environment favourable to hydropower development, with many rivers and streams offering more than 39.9 GW of total hydropower potential;
- A large number of small communities and electricity networks isolated from the national grid and in need of additional capacities; including multipurpose projects that provide a combination of irrigation, water supply and power production.
- Many existing SHP facilities are in need of refurbishment

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Brazil

Geraldo Lúcio Tiago Filho, Camila Galhardo and Luiza Fortes Miranda, Brazilian National Reference Center for Small Hydropower Plants (CERPCH)

KEY FACTS

Population	211,755,692 (est. 2020) [1]
Area	8,510,346 km^2 [2]
Topography	The topography of Brazil is complex and includes a diversity of landscapes, but flat areas predominate. In the north lie the Amazon lowlands, which form the world's largest tropical rain forest. In the northernmost part of the country lie the Guiana Highlands, where the highest peak of Brazil, Pico da Neblina at 2,995.3 metres, is located. The Brazilian Highlands cover more than half of the national landmass including most of the central, eastern and southern parts of the country. The coastline is mainly represented by the Great Escarpment, which in the south-east is surmounted by mountain ranges.[3,4]
Climate	The climate is tropical in the central part of Brazil, temperate in the south and equatorial in the north. In the Amazonian region, average temperatures reach above 28 °C. The north-eastern region is humid, tropical and semi-arid with average temperatures between 20 °C and 28 °C. In the south-east, average annual temperatures vary between 19 °C and 24 °C. However, in the south, the coldest regions have average temperatures below 20 °C. During the winter month of June, the average temperature varies between 11 °C and 18 °C.[5,6]
Climate Change	Climate projections point to an increase in temperatures by 1 °C and 2.2 °C across Brazil by 2060, with the Amazon region experiencing increases of between 2 °C and 3 °C by 2050 and of as much as 5.3 °C by 2085, according to some estimates. The Amazon River delta is expected to experience a rise in sea levels of between 0.2 metres and 2 metres by 2100. Additional expected impacts of climate change in the Amazon region include the increased length of the dry season and heat waves as well as a decrease in precipitation.[7]
Rain Pattern	In the north of the country, specifically the Amazon region, the average annual precipitation varies from 1,700 mm to more than 3,000 mm in some locations. The north-eastern region experiences annual precipitation of between 300 mm and 2,000 mm. In the mid-west, precipitation is well spread and varies from 800 mm to 2,000 mm per year. In the south-east, rainfall ranges between annual averages of 800 mm in the northern part of the state of Minas Gerais and 2,500 mm on the coast of São Paulo. In the south, the precipitation varies from 1,300 mm per year to 2,100 mm per year.[8]
Hydrology	Administratively, the territory of Brazil is divided into 12 river basin districts, each containing one or more river basins. The Amazon River basin district comprises 80 per cent of all surface waters of the country.[9] The major rivers of this basin include the Amazon, Negro, Solimões, Madeira, Trombetas, Purus, Tapajós, Branco, Javari, Juruá, Xingu, Japurá and Iça. The Amazon River is the largest river in the world by volume and accounts for 20 per cent of all the fresh water flowing into the world's oceans. The Amazon River basin, is the largest in the world with an area of approximately 6,900,000 km^2, of which 3,800,000 km^2 are located on the territory of Brazil.[10]

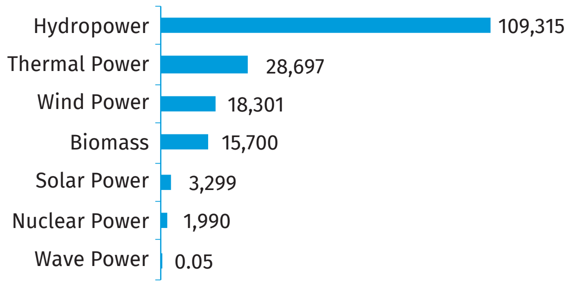
ELECTRICITY SECTOR OVERVIEW

The total installed capacity in Brazil as of April 2021 was 177.3 GW, with hydropower accounting for 62 per cent of the total, conventional thermal power 16 per cent, wind power 10 per cent, biomass 9 per cent, solar power 2 per cent and nuclear power 1 per cent (Figure 1).[11]

In 2019, the electricity sector of Brazil generated a total of 626.3 TWh of electricity.[12] Hydropower contributed 64 per cent, conventional thermal power 13 per cent, wind power 9 per cent, biomass 8 per cent, nuclear power 3 per cent, solar power 1 per cent and other sources 2 per cent (Figure 2).[12]

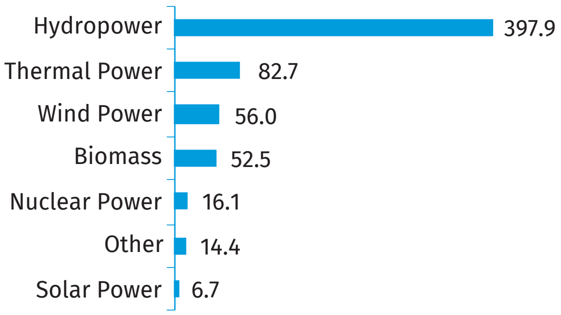
According to The World Bank, Brazil reached 100 per cent access to electricity both in urban and rural areas by 2017.[13] However, in some remote regions far from transmission lines and urban areas, access to electricity remains precarious due to dependence on diesel generators and the complicated logistics of supplying the generators with fuel. The total electricity consumption in 2019 was 545.6 TWh (1 per cent more than in 2018). Of this, 36 per cent was consumed by the industrial sector, followed by the residential (26 per cent) and commercial (17 per cent) sectors. The other sectors represented less than 10 per cent each of the total consumption (Figure 3).[12]

Figure 1. **Installed Electricity Capacity by Source in Brazil in 2021 (MW)**



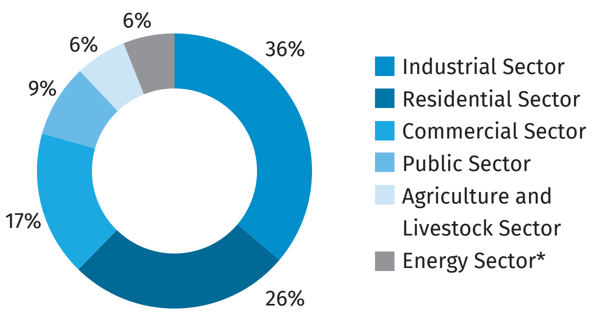
Source: ANEEL[11]

Figure 2. **Annual Electricity Generation by Source in Brazil in 2019 (TWh)**



Source: EPE[12]

Figure 3. **Electricity Consumption by Sector in Brazil in 2019 (%)**



Source: EPE[12]

Note: *Including own use.

The first hydropower plants were built in Brazil at the end of the 19th century, in order to meet the energy needs of the mining, textile and agricultural products processing industries. Until 1950, most of the hydropower plants in the country were small and predominantly located at waterfalls, allowing the direct use of hydropower. Later, in line with the centralized energy planning policies, many federal and state hydropower companies were created. This also induced the implementation of interconnected systems composed of large hydropower plants. Hydropower has been seen as a clean and efficient way to expand the energy capacity of Brazil. Additionally, because of the hydrological complementarity of the Brazilian regions, hydropower projects are well-suited for an interconnected energy system. There are currently 1,377 hydropower plants in Brazil, out of a total of 9,461 power plants of all types (Table 1).[11]

Table 1. **Power Plants in Brazil – May 2021**

Type	*Number*	*Installed capacity (MW)*
Hydropower > 30 MW	219	102,990.4
Hydropower 5–30 MW	425	5,506.4
Hydropower < 5 MW	723	818.2
Thermal power	3,087	44,397.2
Wind power	718	18,300.9
Nuclear power	2	1,990.0
Solar power	4,277	3,298.9
Wave power	1	0.05
Total	**9,452**	**177,302.1**

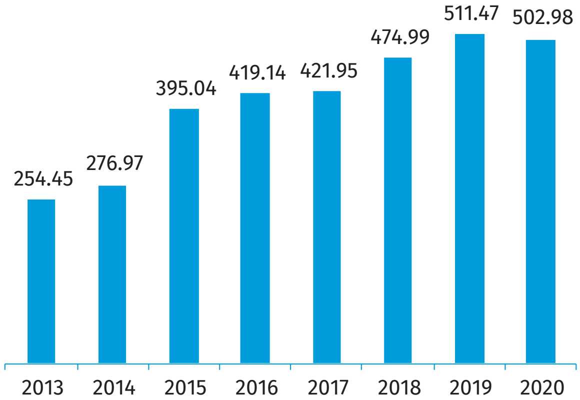
Source: ANEEL11

The process of privatization and unbundling of the electricity sector was started in 1994. The Government intended to change the model from a state-owned monopoly to private competition.[14] However, due to the lack of investment and the 2000 drought, which culminated in a severe crisis for the Brazilian electricity sector in 2001, the plan had to be postponed. The new regulatory framework, established between 2003 and 2004, made investment in renewable energy sources possible and laid down the foundation for the participation of public and private actors.[14] The energy market was standardized and adopted a hybrid model comprising a regulated part and a part of wholesale competitive trade. A recent public consultation (Public Consultation No. 33), which took place in July 2017, showed that most of the agents involved in the electricity sector would prefer the sector to be as free as possible.[15]

The Brazilian electricity sector is regulated through policies formulated by the Ministry of Mines and Energy (Ministério de Minas e Energia, MME) with the assistance of the National Council of Energy Policy (Conselho Nacional de Política Energética, CNPE) and the National Congress. The National Agency of Electric Energy (Agência Nacional de Energia Elétrica, ANEEL) is responsible for analyzing electricity sector resolutions to ensure the welfare of the society and the economy. ANEEL acts as a regulatory agency, while the National Energy System Operator (Operador Nacional do Sistema, ONS) is responsible for coordinating and supervising the centralized operation of the Brazilian interconnected energy system. The Committee for Monitoring the Electric Sector, also associated with the MME, was created to pertinently monitor and evaluate the continuity and security of the power supply across the country. There are also other players in the sector such as the Power Research Company (Empresa de Pesquisa Energética, EPE), which is also associated with the MME and whose role is to perform the necessary studies for planning the expansion of the electricity system. Another agent is the Chamber of Electric Energy Commercialization (Câmara de Comercialização de Energia Elétrica, CCEE), which handles negotiations on energy in the free market.[16]

Consumer tariffs are regulated by ANEEL, while the free-market prices are established through contracts. Electricity prices in Brazil vary according to the distribution company (i.e., the geographic region) and the end-user (residential, industrial, commercial, public service, etc.). Taking the average tariff applied in Brazil in 2020, the price decreased by approximately 1.6 per cent compared to 2019 and reached 0.503 BRL/kWh (0.0975 USD/kWh, based on the annual average dollar exchange rate) (Figure 4).[17]

Figure 4. **Average Annual Electricity Tariff in Brazil (BRL/MWh)**

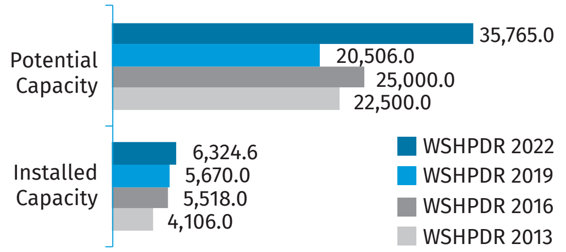


Source: ANEEL[17]

SMALL HYDROPOWER SECTOR OVERVIEW

As of May 2021, there were 1,148 small hydropower (SHP) plants up to 30 MW in operation in Brazil with a total installed capacity of 6,324.6 MW. Of these, the total installed capacity of plants up to 10 MW was 1,608.2 MW.[11] The inventoried potential of SHP in Brazil is 15,765 MW from 1,752 sites, while recent studies point to another 20,000 MW of non-detailed potential for SHP.[18] The total inventoried potential (including operational plants as well as ongoing and planned projects) for plants up to 10 MW is 3,737.8 MW.[11] For the purposes of direct comparison with the previous editions of the *World Small Hydropower Development Report (WSHPDR)*, the up to 30 MW definition of SHP will be used in this chapter. Compared to the *WSHPDR 2019*, installed capacity increased by 11 per cent due to the introduction of new plants. The potential capacity changed based on a more accurate estimate of inventoried potential and new studies carried out on previously not studied rivers (Figure 5).[19] A list of recently commissioned SHP projects is displayed in Table 2.

Figure 5. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2021 in Brazil (MW)**



Sources: ANEEL,[11] ABRAPCH,[18] *WSHPDR 2019*,[19] *WSHPDR 2013*,[20] *WSHPDR 2016*[21]

Note: Data for SHP up to 30 MW.

Table 2. **List of Selected Operational Small Hydropower Plants in Brazil**

Name	*Location*	*Capacity [MW]*	*Operator*	*Launch Year*
Paraíso	Paraíso	1.0	HIDRELÉTRICA PARAÍSO	2020
Jph Catete	Nova Friburgo	1.8	JPH Empreendimentos e Participações LTDA	2020
São Domingos Do Prata	Vista Alegre do Prata	2.2	Usina São Domingos do Prata LTDA	2020
Bandiera Ronfim	Corbélia	2.2	CGH Bandiera Ronfim Geração De Energia LTDA	2020
Serra Velha	Agrolândia	2.5	Hidrelétrica Serra	2020
Ponte Serrada	Passos Maia	4.1	PONTE SERRADA GERAÇÃO DE ENERGIA	2020
Igrejinha	Boa Vista do Cadeado, Jóia	4.9	Boa Vista Do Cadeado	2020
Rio Tigre	Guatambú	5.0	Centrais Elétricas Rio Tigre	2020
Bedim	Marmeleiro, Renascença	6.0	SANTANA	2020
Beleza	Juscimeira	6.5	ENERGETICA PCH	2020
Sede II	Ijuí	7.9	IJUÍ CENTENÁRIA GERAÇÃO	2020
Barra das Águas	Faxinal dos Guedes, Xavantina	8.5	PCH ÁGUAS DO RIO IRANI ENERGÉTICA	2020
Morro Grande	Muitos Capões	9.8	HIDRELÉTRICA MORRO	2020
Piarucum	Dianópolis, Novo Jardim, Ponte Alta do Bom Jesus	10.0	PIARUCUM	2020
Rincão	Entre-Ijuís	10.0	RINCÃO ENERGIA	2020

Name	Location	Capacity [MW]	Operator	Launch Year
ITAPOCUZINHO IIA	Jaraguá do Sul, Joinville	11.7	RIBEIRAO MANSO	2020
Salto do Guassupi	Júlio de Castilhos	12.2	Salto do Guassupi Energética	2020
Poço Fundo	São José do Vale do Rio Preto	14.0	POÇO FUNDO ENERGIA	2020
Tamboril	Cristalina	15.8	SÃO BARTOLOMEU GERADORA DE ENERGIA RENOVÁVEL	2020
Quebra Dentes	Júlio de Castilhos, Quevedos	22.4	Quevedos Energética	2020

Source: ANEEL[11]

The definition of SHP in Brazil has evolved over time. The first definition was set in 1982 and restricted SHP to 10 MW. However, this definition does not fit the present reality. As a result, ANEEL Resolution No. 673 of 2015 established a new definition of SHP as hydropower plants used for self-generation or independent electricity generation and with an installed capacity above 3 MW and below 30 MW.[22] Furthermore, the maximum reservoir area was limited to 13 km² (excluding the regular riverbed). In case of a reservoir area exceeding 13 km², the plant is still considered an SHP plant if this is at least a weekly regularized reservoir or if it has proven purposes other than electricity generation. Resolution No. 673 also states that hydropower projects below 3 MW have simpler implementation rules, only requiring the notification of ANEEL. This serves as an important incentive for SHP plants below 3 MW, although they are still required to abide by environmental and other state regulations.[23]

Law No. 13.360 of 17 November 2016 established a new definition of SHP as plants with an installed capacity from 5 MW to 30 MW.[23] However, the plants from 3 MW to 5 MW that were commissioned before the new law are still classified as SHP. Therefore, the actual installed capacity of all hydropower plants considered as SHP in the country exceeds the capacity of SHP according to the new definition. Furthermore, the definition of reservoir area of SHP plants as per ANEEL Resolution No. 673 is still being used. The Normative Resolution of ANEEL No. 765 of 2017 establishes the procedures for obtaining grants for hydropower projects between 5 MW and 50 MW that do not have all the characteristics of SHP plants listed above.[24] Finally, Normative Resolution No. 482 of 2012 regulating distributed generation, was updated by Normative Resolution No. 786 of 2017, which changed the maximum size limit for plants for distributed generation from 3 MW to 5 MW.[25,26] This means that more SHP plants can be considered as distributed generation plants and can enjoy the regulatory advantages available to this kind of generation, which were previously established by Resolution No. 673, including a simplified licensing process and access to the net metering tariff. Hydropower plants up to 5 MW (for distributed generation) are further classified as micro if their capacity is up to 75 kW and as mini if above 75 kW and below 5 MW.[25,26]

According to The Brazilian Ten-Year Plan for Energy Expansion 2029 (Plano Decenal de Expansão de Energia 2029, PDE 2029), the Government predicts that the installed capacity of SHP will reach 9,045 MW (4 per cent of total installed capacity) in 2029. As of 2021, the installed capacity of SHP in Brazil (6,324.6 MW) represented 3.6 per cent of total installed capacity and 93 per cent of the 2021 SHP installed capacity target of 6,787 MW.[27] This shows that the relative share of SHP in the country's energy mix is not expected to grow substantially. For comparison, the share of wind power is expected to rise from 11 per cent in January 2021 to 17 per cent in 2029, based on the assumption that the available incentives, such as tax exemptions, stay in place and continue to have a positive impact on the development of the source.[27] Several planned SHP projects are listed in Table 3.

Table 3. **List of Selected Planned Small Hydropower Projects in Brazil**

Name	Location	Capacity [MW]	Developer	Development Stage
Amarají	Pernambuco, Amarají River	8.5	Usina União e Indústria S.A	Intention of grant registered
Bom Jesus	Mato Grosso, Tadarimana River	8.8	Bom Jesus Agropecuária Ltda.	Intention of grant registered
Catanduva	Paraná, Iratim River	18.0	Catanduva Geração de Energia Ltda.	Executive Summary adequated
Água Branca	Paraná, Alto Ribeira River	22.0	Valdevir Gromowsk	Intention of grant registered
Brito	Minas Gerais, Pirange River	23.0	Petraprime Gestão e Administração de Propriedade Imobiliária Ltda.	Intention of grant registered

Source: ANEEL[11]

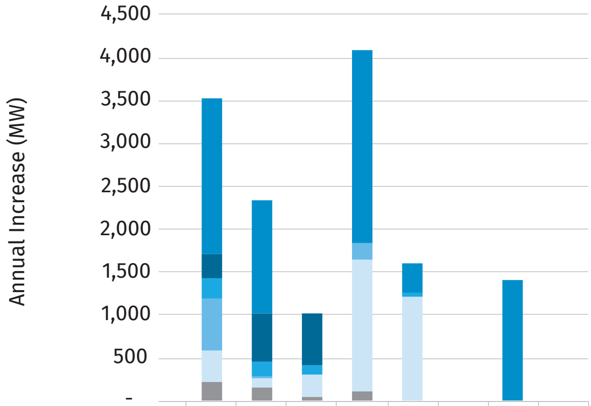
SHP represents a renewable energy alternative which brings several benefits to the energy sector of Brazil, such as synergy with other sources as well as flexibility of operation and storage. Often, SHP also brings social and economic development to the areas where the plants are installed. In most cases, SHP entrepreneurs are required to invest in some local improvements as a mitigation measure for the environmental impact caused by the project. In particular, electrification through development of SHP in Brazil has been correlated with broad-based job creation and increases in labour productivity in the affected regions.[28,29] Although possible negative consequences of SHP development are reduced by the above measures, the general public in Brazil seems to associate the disadvantages of large hydropower with SHP as well. This has a significant negative impact on the public perception of SHP in the country and, therefore, on the prospects of SHP development.

RENEWABLE ENERGY POLICY

The Incentive Programme for Alternative Energy Sources (Programa de Incentivo às Fontes Alternativas, PROINFA) launched in 2002 was one of the major programmes to promote renewable energy sources in Brazil. The programme's primary focus was on biomass, wind power and SHP. This programme was similar to a feed-in tariff scheme, but was aimed at large-scale projects. Although PROINFA contributed to the diversification of the country's energy mix and the expansion of the share of some renewable energy sources, the prices of electricity generated from renewable energy sources remained high and the programme has been discontinued. The current mechanism to promote renewable energy sources in Brazil is through power auctions. Specific auctions are offered for a restricted group of energy sources, serving as an incentive for large-scale projects. Additionally, the net metering model was chosen for on-site generation, benefiting mainly the solar photovoltaics market.

In the last few years, wind power projects have been showing lower prices in the auctions and the construction and operating costs of SHP in Brazil have been higher than those of other energy sources. Besides, SHP electromechanical equipment is expensive and does not receive tax exemptions as does wind power and solar power equipment (e.g., the tax on circulation of goods and services). As a result of the balance of relative costs and incentives benefitting primarily large projects and non-hydropower renewable energy sources, SHP has lately been losing its share of the energy mix to other renewable sources. The Ten-Year Energy Expansion Plan 2029 (PDE 2029) of Brazil shows that SHP projects contracted as of 2019 were to account for only 6 per cent of the total power generation capacity to be commissioned in 2020, less than 8 per cent in 2021, 11 per cent in 2022, 0.2 per cent in 2023 and 2 per cent in 2024. Considering the entire period from 2020 to 2029, SHP represents only 4 per cent of the total contracted capacity, while wind power and solar photovoltaics represent 25 per cent and 10 per cent, respectively (Figure 6).[27] Although these data demonstrate that currently solar and wind power are growing faster than SHP, the PDE 2029 also indicates a wide range of SHP projects not yet developed that may be important for the energy expansion.

Figure 6. **Contracted Capacity Expansion in Brazil until 2029**



	2020	2021	2022	2023	2024	2025	2026	2027
Thermal Power	1,802	1,305	-	2,238	363	-	1,405	-
Photovoltaic Power	298	557	585	-	-	-	-	-
Hydropower < 30MW	225	177	111	10	38	-	-	-
Hydropower > 30MW	611	36	-	204	-	-	-	-
Wind Power	353	107	264	1,521	1,212	-	-	-
Biomass and Biogas	231	147	50	115	-	-	-	-

Source: EPE[27]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The current environmental licensing process for SHP presents some barriers for development. According to the resolution CONAMA 01/86, power plants above 10 MW, regardless of the energy source, are considered as potential sources of negative environmental impact.[30] SHP projects between 10 MW and 30 MW therefore require an Environmental Impact Assessment (Estudo de Impacto Ambiental, EIA) and an Environmental Impact Report (Relatório de Impacto Ambiental, RIMA).

SHP projects between 3 MW and 10 MW, however, are only required to prepare a Simplified Environmental Report (Relatório Ambiental Simplificado, RAS). Hydropower plants below 3 MW have to go through an even less rigorous process of environmental licensing. On the other hand, SHP projects of this size are generally considered expensive and unattractive to investors. It should be noted that the limit of 3 MW set by the Environmental Law is lower than the 5 MW maximum capacity limit of SHP plants for distributed generation established by the ANEEL Normative Resolution No. 786. This is due to the fact that in Brazil environmental laws are treated separately from the laws on incentives for energy sources. Overall, the environmental licensing process for wind power and solar photovoltaic projects is faster and simpler than for SHP, serving as another incentive for these two renewable energy sources to the detriment of SHP.

Nonetheless, there are additional instruments of support for SHP as well. The key ones include:

- Free access to the transmission and distribution networks;

- Discount of at least 50 per cent on the tariffs for using the transmission and distribution systems;
- Exemption from the tax on land use for inundation;
- Incentives for distributed generation (plants up to 5 MW);
- Energy Reallocation Mechanism (MRE), in which SHP plants can participate optionally.

Despite the huge hydropower potential available in Brazil and the extensive national experience in hydropower generation, the current policies and financial mechanisms do not seem to provide an adequate market for the expansion of SHP. In contrast, wind power and solar photovoltaic power have recently been the main focus of policies promoting the expansion of renewable energy sources, with remarkable results. In the short term no changes to this scenario are expected. The stabilization of the relatively new renewable energy sources (solar photovoltaic power and wind power) in the national market is likely required in order for more competitive conditions for the expansion of the SHP plants to emerge.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

According to several studies published as part of the 2015 report "Scenarios and Alternatives for Adaption to Climate Change", climate change is expected to have severe impacts on the operation of existing hydropower plants in Brazil and the viability of planned projects. In particular, river flow to the country's four largest hydropower plants (Itaipu, Furnas, Sobradinho and Tucuruí) is expected to decrease by 38-57 per cent by 2040. The flow of the Xingu River in Amazonia feeding into the Bel Monte hydropower plant, currently nearing completion, is expected to decrease by between 25 and 55 per cent. This threatens the viability of the project, which is already expected to operate below full capacity due to seasonal flow variability.[31]

The Amazon region is expected to be hit particularly hard by climate change due to ongoing deforestation. A recent study of the climate change impacts on hydropower for the period 2026–2045 relative to the baseline period 1986-2005 in the Tapajós basin, much of which is run-of-river and highly sensitive to seasonal flow variability, projected a loss in generation of 312-430 GWh per month during the dry season. It also suggests a delay in the peak generation period by 22–29 days as well as an increase in interannual generation variability from 548 GWh to 713–926 GWh due to the combined effects of deforestation and climate change. The study additionally underlines that smaller hydropower projects are less prone to large-scale miscalculations of expected capacity in conditions of climate uncertainty.[32]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

SHP projects are currently in a disadvantaged position in Brazil in relation to other renewable energy sources, mainly wind power, which receives more incentives. The key barriers to SHP development include:

- Limited incentives compared to other renewable energy sources, which makes SHP projects less competitive;
- Strict requirements for the environmental licensing process for plants between 10 MW and 30 MW;
- High cost of constructing and operating SHP plants in comparison to other renewable energy sources such as wind and solar power in the context of Brazil;
- The costs of civil construction and electromechanical equipment are elevated and are not covered by tax exemptions;
- A generally negative public perception of all hydropower, mainly due to campaigns against large hydropower plants.

Factors enabling the development of SHP in Brazil include:

- A long history of hydropower development;
- Abundant unrealized SHP potential;
- Regulatory and licensing incentives for SHP below 5 MW, especially for SHP below 3 MW, and discounts/exemptions in the case of certain fees and taxes.

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Chile

Patrick Furrer, Jorge Saavedra and Patricio Muñoz, AFRY Chile

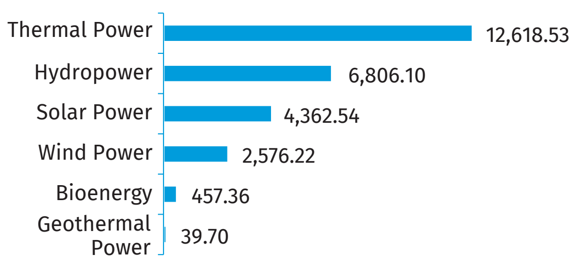
KEY FACTS

Population	19,116,209 (2020)[1]
Area	756,100 km² (continental territory), 2,006,096 km² (continental, Antarctic and insular)[2]
Topography	Continental Chile is characterized as mountainous, with no more than 20 per cent of flat surface. The three main features of the relief of continental Chile are the Andes Mountains to the east, the coastal range to the west and the intermediate depression between the two mountain ranges. The highest peak is the Ojos del Salado at 6,893 metres in elevation. Between continental and southern Chile there is a submerged mountain range whose highest peaks emerge to form islands, eventually reaching the north-eastern tip of the Antarctic peninsula. Rapa Nui Island (Easter Island) presents a relief characterised by plains and volcanoes.[2,3]
Climate	Chile has a variety of climates: desert, Mediterranean steppe, warm temperature rainy, temperate rainy, maritime rainy, cold steppe, tundra and polar (from north to south). In the Andes, highland climate prevails and on its high peaks, icy weather. Rapa Nui has a subtropical climate with oceanic influence characteristics. Temperatures vary depending on the region; in the north, daily averages range from 12 to 23 °C. The central region average daytime temperatures range from 9 to 21 °C depending on the time of year, while in the south, average daily temperatures range from 2 to 16.8 °C.[2,4]
Climate Change	As a consequence of climate change, several studies have projected a significant decrease in mean monthly flows between the Region of Coquimbo and Region of Los Lagos (from 30° to 42° South) and an increase in the elevation of the zero isotherm, which implies a reduction of the water storage of nivo and nivo-pluvial basins as well as an increase in the risk of flood and landslide events.[5]
Rain Pattern	Rainfall varies in amount and distribution across the territory and increases towards the south. In the far north, the average annual rainfall is less than 1 mm, while at the southern tip it can reach 5,000 mm or more.[2]
Hydrology	As a result of the relief and the narrowness of the territory, the rivers are short, with steep slopes, low-flow, torrential and are unsuitable for navigation, but have great hydropower potential. The northern rivers are fed by snow thawing, the central ones have a mixed feeding, the southern ones by rainfall and the austral ones have mixed regimes, fed by rain and thawing glaciers. The longest river is the Lao river of 440 km, spanning the Andean mountain range and the Atacama desert. It has several main tributaries: the Salado River, the San Salvador River and the San Pedro de Inacaliri River. The next longest river is the Bío-Bío River, stretching 380 km from lakes Icalma and Galleutué, through the Andean valley. Both the Lao and the Bío-Bío rivers drain into the Pacific Ocean.[26]

ELECTRICITY SECTOR OVERVIEW

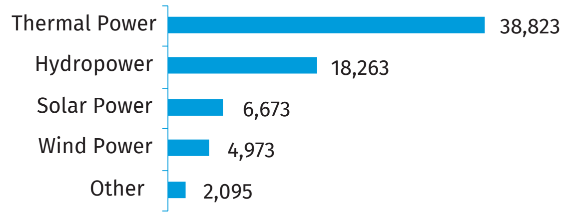
In October 2021, the total installed generating capacity of Chile was 26,653 MW (Figure 1), of which 99 per cent corresponded to the National Electrical System (SEN).[7] Hydropower is the most important source of electricity in Chile, making up 27 per cent of the total installed capacity. The total electricity generated in 2020 was 70,828 GWh (Figure 2).[8] There is a noticeable trend towards an increase in renewable energy generation, mainly in wind and solar power. As a result of the Paris agreement commitments by the government of Chile, there is a plan to decarbonize the energy mix; currently, there is an agreement to shut down 11 coal power plants by 2024, which represents 1,731 MW and 31 per cent of the total capacity of coal power plants.[9] An even more ambitious plan for accelerated decarbonization is also under discussion, but is not yet approved because of the possible marginal cost increases this would bring.

Figure 1. **Installed Electricity Capacity by Source in Chile in 2021 (MW)**



Source: CNE[10]

Figure 2. **Annual Electricity Generation by Source in Chile in 2020 (GWh)**



Source: NCE[8]

In the 1970s began the privatization and segmentation of the Chilean electricity market, starting with the distribution segment (originally owned by the Chilean National Electricity Company, ENDESA), followed by the generation and transmission segments, which were privatized and afterwards separated in the mid-1990s. Generation, transmission and distribution are unbundled horizontally. The sectors are, however, integrated vertically. Electricity system prices follow a marginalist approach and there are nodal prices given the grid constraints. Until 2005, the generation segment was dominated by three national companies, Enel (formerly ENDESA Chile), AES Gener (formerly GENER) and Colbún. The situation has changed substantially with the appearance of other competitors (medium- and small-sized players) with more than 400 generation companies currently active in the Chilean energy market.

The largest electrical system is the National Electrical System (SEN), which is the interconnection of the previous North Interconnected System (SING) and the Central Interconnected System (SIC). SEN serves approximately 98 per cent of the country's population. Other smaller networks are the Aysén System (SEA), Los Lagos generating unit and Magallanes System (SEM).

The transmission system can transport electricity from generating plants located throughout the country to distribution companies' substations and industrial consumers. The voltage levels in lines are between 23 kV and 500 kV, at a nominal frequency of 50 Hz. Transmission is dominated by four historical major players — TRANSELEC, ENGIE (Suez, E-CL), TRANSNET (CGE), ENEL (Chilectra) — as well as one new player INTERCHILE since the construction of the 500 kV system. At the moment of writing of this chapter, there was a bid for a HVDC line of ±600 kV between the Kimal and Lo Aguirre substations, which will improve the transport of electricity between the north and the central system of Chile. In terms of regional interconnections, an interconnection exists between the north of the country and Salta province in Argentina. The line has a length of 408 kilometres, 345 kV of rated voltage and is connected between the substations of Andes and Cobos (both owned by AES). According to the National Electrical Coordinator (CEN), the line is still awaiting approval and consequently there is no power flow registered for the moment.

The distribution system is principally in the hands of four companies: ENEL, CGE, Chilquinta and SAESA. The distribution system, consisting of lines, substations and equipment, is established in two voltage ranges (medium and low voltage). In the low voltage range, there are three rated voltages defined by the Chilean regulations. It is usual to use 380 V and 220 V in three-phase and single-phase installations, respectively:

- Medium voltage (Line-Line): 2, 4, 3.3, 4.16, 6.6, 12, 13.2, 13.8, 15 and 23 kV;
- Low voltage (Line-Line): 380, 480, 660 V;
- Low voltage (Line-Neutral): 220, 277, 380 V.[11]

As established by the General Services Law, the main bodies involved in regulating the electricity market are:

- Ministry of Energy: the public agency responsible for developing and coordinating the plans, policies and standards for the proper functioning and development of the energy sector, ensuring compliance and advising the Government on all matters related to energy;
- National Commission Energy: a public and decentralized body, with its own assets and full capacity to acquire and exercise rights and obligations. Its function is to analyze prices, tariffs and technical standards to which energy production, generation, transmission and distribution companies must adhere in order to have a sufficient, safe and quality service, compatible with the most economical operation;
- Electricity and Fuel Superintendence (SEC): the public agency responsible for overseeing the energy market, in order to have safe and quality products and services, as well as supervising compliance with electrical regulations in the country;
- National Electrical Coordinator (CEN): an independent body responsible for ensuring the security of the service in the electrical system, guaranteeing the most economical operation for all system installations, and planning the development of the transmission system. Additionally, it adopts the pertinent measures to monitor the chain of payments of the economic transfers subject to their coordination, guaranteeing their continuity;
- Panel of experts: a body created by law, with limited competence, made up of professional experts, whose function is to pronounce, by means of rulings with binding effect, on those discrepancies that occur in relation to the matters indicated in the General Law of Electrical Services (studies, tariffs, plans, etc.), and in other laws on energy matters;
- Ministry of Environment: the body that grants the approval of the environmental impact studies for projects in the sector;
- Municipalities: they oversee the issue of permits for the use of public assets.[9,12,13,14,15,16,17]

The average sale price of electricity (average node price in SEN) in December 2020 was 58.56 CLP/kWh (42.16 USD/MWh).[18] This value, however, does not consider the costs of distribution or the charge for the use of the national transmission system.

SMALL HYDROPOWER SECTOR OVERVIEW

Chilean Law No. 20.257 defines a small hydropower (SHP) plant as a hydropower plant with a maximum installed capacity of below 20 MW.[19] SHP is considered as a form of non-conventional renewable Energy (ERNC). The Renewable Energy and Energy Efficiency Programme of the Ministry of Energy classifies hydropower into micro-, mini- and small hydropower (Table 1).

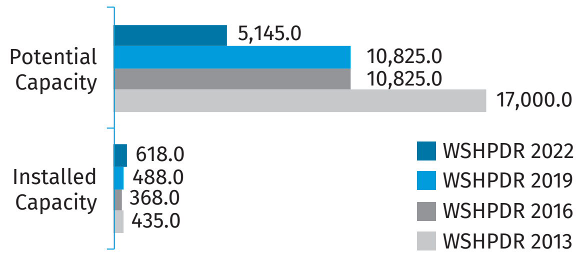
Table 1. **Classification of Small Hydropower in Chile**

Category	*Installed capacity*
Micro	5 kW–100 kW
Mini	100 kW–1 MW
Small	1 MW–20 MW

Source: Ministry of Energy [20]

The available capacity of SHP up to 20 MW as of January 2021 was 618 MW, distributed among 130 plants (Table 2). For SHP up to 10 MW, the installed capacity was 304 MW from 110 plants.[21] In comparison to data from the *World Small Hydropower Development Report (WSHPDR)* 2019, installed capacity has increased by almost 27 per cent (Figure 3). Conversely, the estimated potential has decreased due to new data made available, based on improved analytical methods and reflecting shrinking water availability in the country.[22] Additionally, in 2020 there were 77 MW of SHP under construction and 779 MW of SHP project with an Environmental Qualification Resolution (RCA), meaning that they had a permission to start SHP construction.[23]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Chile (MW)**



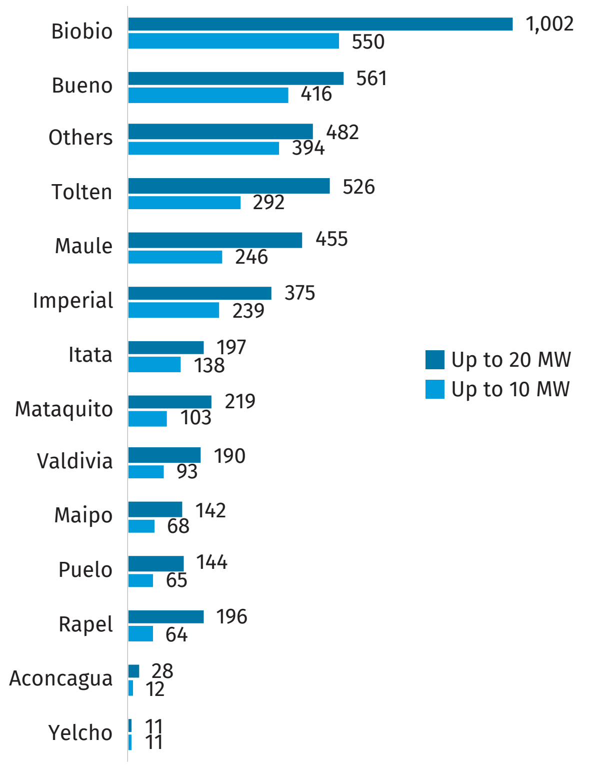
Source: NEC,[16] Ministry of Energy, General Directorate of Water & University of Chile,[21] *WSHPDR 2013*,[24] *WSHPDR 2016*,[25] *WSHPDR 2019*[26]

Note: Data for SHP up to 20 MW.

The increase in the installed capacity of SHP was mainly due to regulatory changes in Decree 244, which regulates small, distributed power plants, referred to as PMG(D)s (Pequeños Medios de Generación, Distribuida) in Chile. It has simplified the processing of projects of less than 9 MW connected to the distribution network, particularly for projects under 1.5 MW that have no significant impact on the grid (known as INS in Chile). INS projects allow avoiding some electrical studies and steps to follow for the connection, which helps avoid important costs in the processing of the projects.[27]

The estimated SHP undeveloped potential up to 10 MW is equivalent to 2,691 MW and for SHP up to 20 MW is 4,527 MW (Figure 4). The most promising rivers are the Biobio (550 MW and 1,002 MW), Bueno (416 MW and 561 MW) and Tolten (292 MW and 526 MW).[17] This corresponds to the technical potential, which considers the Rights of Use of Non-Consumptive Water for installed power greater than 0.1 MW and plant factors greater than 0.5. This does not consider the potential in the southern part of the country (Aysén region) due to environmental restriction.[28] For SHP up to 10 MW, the total technical potential (including developed capacity) was estimated at 2,995 MW and for hydropower plants up to 20 MW at 5,145 MW.[17] An additional potential associated with reservoirs used for irrigation works was studied in 2007 for Rights of Use of Consumptive Water and is estimated at 866 MW. Of the known potential, 558 MW of capacity has less than 20 MW and flows above 4 m³/s.[29] Planned projects on these sites can be seen in Table 3.

Figure 4. **Estimated Potential of Small Hydropower up to 10 MW and 20 MW by River in Chile (MW)**



Source: Ministry of Energy, General Directorate of Waters & University of Chile21

Table 2. **List of Selected Operational Small Hydropower Plants in Chile**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Hp mocho	Río Bueno, Región de Los Ríos	15.45	–	Run-of-river	Hidromocho sa	2021/2022
Pmgd hp panguipulli	Panguipulli, Región de Los Ríos	0.35	–	Run-of-river	Latinoamericana	2021/2022

Name	Location	Capacity (MW)	Head (m)	Plant type	Operator	Launch year
Pmgd hp viña tarapacá	Isla de Maipo, Región Metropolitana de Santiago	0.25	–	Run-of-river	Andes energy capital	2021/ 2022
Pmgd hp central hidroeléctrica chilco	Lago Ranco, Región de Los Ríos	0.20	–	Run-of-river	Ganadera y forestal carran ltda	2021/ 2022
Pmgd hp el brinco	Mulchén, Región del Biobío	0.12	–	Run-of-river	Hidro munilque spa.	2021/ 2022
Pmgd hp el manzano (pelarco)	Pelarco, Región del Maule	0.15	–	Run-of-river	Central hidroelectrica el manzano spa	2021/ 2022
Hp palmar	Puyehue, Región de Los Lagos	8.57	–	Run-of-river	Hidropalmar s.a.	2020
Hp correntoso	Puyehue, Región de Los Lagos	8.38	–	Run-of-river	Hidropalmar s.a.	2020
Pmgd hp la compañía ii	Codegua, Región del Libertador Gral. Bernardo O'Higgins	2.56	–	Run-of-river	Empresa eléctrica la compañía spa	2020
Ch cochamo	Cochamó, Región de Los Lagos	0.68	158.0	Run-of-river	Sagesa s.a.	2020
Pmgd hp cosapilla	Putre, Región de Arica y Parinacota	0.50	–	Run-of-river	Engie	2020
Hp cumbres	Río Bueno, Región de Los Ríos	17.86	–	Run-of-river	Cumbres s.a.	2019
He convento viejo	Chimbarongo, Región del Libertador Gral. Bernardo O'Higgins	16.00	–	Reservoir	Embalse convento viejo s.a.	2019
Hp dos valles	San Fernando, Región del Libertador Gral. Bernardo O'Higgins	4.45	–	Run-of-river	Hidroelectrica dos valles spa	2019
Hp palacios	San Fernando, Región del Libertador Gral. Bernardo O'Higgins	3.02	–	Run-of-river	Hidroelectrica palacios spa	2019
Pmgd hp msa-i	Villarrica, Región de La Araucanía	3.00	–	Run-of-river	Minicentrales araucanía s.a.	2018
Pmgd hp santa elena	Cunco, Región de La Araucanía	2.75	–	Run-of-river	Central hidroeléctrica santa elena s.a.	2018
Hp alto renaico	Mulchén, Región del Biobío	1.38	–	Run-of-river	Espinos s.a	2018
Hp río colorado	San Clemente, Región del Maule	16.47	–	Run-of-river	Rio Colorado	2017
Pmgd hp melo	Quilleco, Región del Biobío	2.97	–	Run-of-river	Socer s.a.	2017

Source: CEN[20]

Table 3. **List of Selected Planned Small Hydropower Projects in Chile**

Name	Location	Capacity (MW)	Head (m)	Plant type	Developer	Planned launch year	Stage of Development
Río Maño	Panguipulli, Región de Los Ríos	3.0	80	Run-of-river	Bosch Rivera Limitada	2021	In environmental evaluation
El Portal	Mulchén, Región del Biobío	1.2	12.8	Run-of-river (irrigation canal)	CENTRAL EL ATAJO SPA	2021	Approved environmental evaluation
Llancalil	Pucón, Región de la Araucanía	6.9	105	Run-of-river	Inversiones Huife Ltda.	--	In environmental evaluation
Las Nieves	Melipeuco, Región de la Araucanía	6.5	400	Run-of-river	Hidroeléctrica Las Nieves SPA	2021	Under construction
Pasada Cipresillos	Machalí, Región del Libertador General Bernardo O´Higgins	9	336	Run-of-river	Eléctrica Cipresillos	2021	Under construction

Source: Environmental Evaluation System[30]

Table 4 displays sites with hydropower potential, however, there is no public information on whether there are any planned SHP projects on these sites. As investment in generation projects is private, in most cases, SHP projects are made public when they enter the Environmental Evaluation System.

Table 4. **List of Selected Small Hydropower Projects Available for Investment in Chile**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of project*	*Type of site (new/refurbishment)*
Río Cautín	Curacautín, Región de la Araucanía	15.6	36	Run-of-river	New
Estero Cañileo	Quilleco, Región del Biobío	6.3	125	Run-of-river	New
Los Pellines	Coihueco, Región de Ñuble	3.8	197	Run-of-river	New
Río Longaví	Longaví, Región del Maule	13.2	100	Run-of-river	New
Río Ancoa	Linares, Región del Maule	5.4	288	Run-of-river	New

Source: Ministry of Energy, General Directorate of Waters & University of Chile[17]

Table 5. **Definition of Renewable Non-Conventional Energy Generators in Chile**

Classification	*Meaning*
Small distributed generation plant (PMGD)	Plants ≤ 9 MW, connected to the facilities of a distribution company
Small generation plant (PMG)	Plants ≤ 9 MW, connected to the facilities of a transmission system
Non-conventional generation plant (MGNC)	Non-conventional renewable energy plants ≤ 20 MW; the MGNC category is not exclusive with the above categories indicated.

Source: Ministry of Economy, Development and Reconstruction[30]

RENEWABLE ENERGY POLICY

In 2016, the Ministry of Energy finished a participative process for the elaboration of a long-term energy policy called Energía 2050, which included the participation of different actors from the Government, industry, general public and universities.[31] This process concluded with the Roadmap 2050 and the 2050 Energy Policy.[32,33] These documents are based on four main objectives, including generating 60 per cent of energy from renewable sources by 2035 and 70 per cent by 2050.

In 2018, the Ministry of Energy published Energy Route 2018–2022, a roadmap for the four years of the new Government with seven lines of action: energy modernization (regulation and institutions), socialization of the projects, energy sector development, grid diversification with local low-emission energy, efficiency and electrification of transport, residential and industrial sector energy efficiency and energy education and capacity building.[34] Achievements include time reduction in the environmental approval process and the elaboration of a master plan for decommissioning or reconversion of coal power plants.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Ministry of Economy Decree 244 regulates the mini- and small hydropower sector, which belongs to the category of non-conventional renewable energy (ERNC) generators along with geothermal power, wind power, solar power, biomass and co-generation (Table 5).[9]

Law 19.940 includes the fee for small ERNC generators access to the transmission system and regulates the cost for the connection of small distributed ERNC generators to the distribution systems. Law 20.018 requires that energy generators provide at least 5 per cent of their energy through sustainable means or purchase the equivalent from renewable sources. This percentage is set to rise to 10 per cent by 2024.

Currently, a controversial amendment of the Chilean Water Code is under discussion in the National Congress.[35] The amendment project aims to modify the concept of water rights in order to: limit their exercise; make them temporary (20 or 30 years, with the possibility of renewal); limit the exercise of water rights in the event of scarcity situations; establish a “use it or lose it” clause; facilitate the Government’s intervention into hydrological areas and reform the non-use fee payment.

Law 19.300 on the general bases of environment requires that every energy generation plant with a capacity larger than 3 MW and a transmission line with voltage greater than or equal to 23 kV together with its substations must enter the system of environmental impact evaluation (SEIA). Projects that enter the SEIA must present an Environmental Impact Declaration, unless their impacts significantly change or intervene in some aspects defined in the law (population health, renewable natural resources, community resettlement and landscape value). In such cases, a full Environmental Impact Evaluation must be presented. In general, SHP projects present an Environmental Impact Declaration.

Law 20,698 was published in 2013 with the main goal of extending the energy mix by incorporating ERNC generation projects. This law set new goals for ERNC generation, changing the target share from 10 per cent by 2024 to 20 percent by 2025. Also, the Ministry of Energy has to make public tenders for annual blocks of energy provided by ERNC sources.

In 2016, Law 20,936 creating a new electric transmission system and an independent coordination agency of the national electric system was published. The main objectives of this law were to increase competition in the electric market, remove entry barriers to the energy generation market and boost the development of ERNC.

In 2016, the environmental evaluation services published a methodological manual for the calculation of the ecological flow. This is now used to define an independent ecological flow that prevails over the water right ecological flow. Although, this is only a guide, it is used as part of the regulation.

COST OF SMALL HYDROPOWER DEVELOPMENT

The development of SHP projects must consider different factors, such as water rights availability, environmental impacts, access roads, hydrological and geotechnical conditions, which are specific to the project location. The cost of SHP development is highly dependent on the project's location.[36]

Based on information provided by developers of generation projects, the National Commission of Energy has estimated the average development cost of run-of-river SHP plants (up to 20 MW) to be 3,263 USD/kW. The average variable cost depending on energy generation is estimated at 1.3 USD/MWh and the operational and maintenance cost non-related to energy generation is 1 per cent of the total expenditure. The total time of construction was estimated as three years.[32]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

In Chile, state financial mechanisms are provided mainly by the Corporation of Production Development (CORFO) and do not target specifically SHP but ERCN projects in general. CORFO created a special credit scheme to finance investment into construction, operation and commissioning of ERCN projects, with a maximum financing amount of USD 15 million.[37] In 2020, as a measure to mitigate the economic effects of the Covid-19 crisis, CORFO created a Green Credit to boost ERCN projects, energy efficiency and circular economy, with a maximum financing amount of USD 7 million for ERCN generation projects.[38]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Chile is highly vulnerable to climate change and meets most of the nine vulnerability criteria set by the United Nations Framework Convention on Climate Change (UNFCCC). Hydropower generation potential is expected to decrease by 11 per cent between 2011 and 2040 and by 22 per cent between 2071 and 2099 under the emission scenario A2 and by 10 and 16 per cent for the same periods, respectively, under the emission scenario B2.[3]

One measure to mitigate the effects of climate change on SHP is to add more flexibility by incorporating new technologies, such as using lithium-ion batteries to store energy. An example of this is the Virtual Dam initiative of AES Gener that installed batteries providing 10 MW for five hours at the run-of-river plant Alfalfal I (178 MW).[39] This initiative could be replicated at a smaller scale for SHP plants.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Chile has abundant energy resources and has made some effort in order to promote the development of renewable energy technologies, including SHP. However, there are barriers to their development and implementation. Regarding SHP, there are social, institutional and technical barriers, including the following:

- Ownership of water: Hydropower potential is not necessarily perceived as a natural condition of the water resource;
- Use of water: Competition for multiple uses in the river basins, in particular, with other productive uses, conservation and tourism;
- Asymmetry of information: Lack of information and good communication between the community and the developers generates mistrust;
- Balance of cost, risks and benefits: Lack of information within the communities about the cost, potential risks and real benefits associated with SHP projects generates the sensation of being robbed of their resources. The communities see only the external cost and usually overestimate the potential risks and revenues for the developer;
- The public at large feels left out of the planning of hydropower development, in particular, in areas with indigenous population;
- Absence of unified criteria of environmental impact assessment for SHP;
- A long approval process for the environmental and construction permits;
- Water rights can be monopolized;
- Ecological flow included in the water right is not considered in the environmental approval, a new ecological flow has to be defined;
- The water rights legal constitution is under modification;
- Normally, SHP development takes place far from the transmission lines, so that the project developers have to invest in the lines as well, which often makes projects unfeasible;
- Because of climate change it is expected that hydropower potential will decrease by 11–22 per cent;
- The central part of Chile has faced a mega-drought from 2010 to the present with mean rainfall deficits of 20–40 per cent;
- Increasing water stress due to climate change.

The following points summarize the main enablers for SHP development that have been identified:

- Due to its geography and climate, Chile has a high hydropower potential, a large part of which remains undeveloped;
- Aiming to reduce greenhouse gas emissions, several

state initiatives and policies have been or will be generated to boost renewable energy generation, including SHP. There is an ongoing decarbonization plan that has as goal to completely remove coal-fired thermal power plants from the energy mix by 2040. This policy could pose an opportunity for SHP because the shutdown of thermal power plants entails a reduction in baseload production, which could be provided for by SHP.

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Colombia

Alexandra Planas Marti, Inter-American Development Bank

KEY FACTS

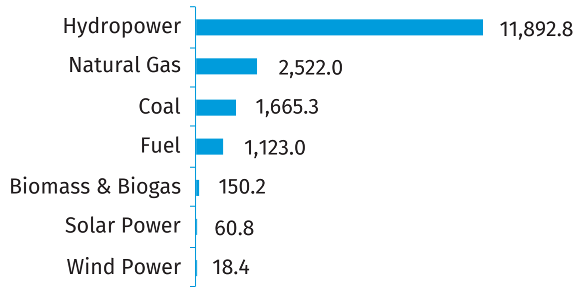
Population	48,258,494 (2018)[1]
Area	1,141,748 km² [2]
Topography	Colombia is situated in the northern part of South America and has a coastline on both the Pacific Ocean and the Caribbean Sea. The Andes Mountain Range crosses the western and central parts of the country, and the highest point in the country is the Sierra Nevada de Santa Marta (5,775 metres).[2] On the contrary, the eastern region of the country is characterized by extensive plains.
Climate	The climate of Colombia is shaped by its varied topography. The average temperature in the Pacific region is 26-28 °C, in the Orinoco region 24-28 °C, in the Amazonian 24-26 °C region and over 26 °C in the Caribbean region. At the same time, the average temperature in the Andean region varies between 8 °C and 24 °C.[3,4]
Climate Change	Even though Colombia emits 0.46 per cent of global greenhouse gas emissions, the country is highly vulnerable to certain effects of climate change such as floods, changes in water resources and rain patterns, desertification of productive soils and health issues like malaria and dengue fever.[5]
Rain Pattern	The highest average precipitation level is found in the Pacific region, where most municipalities receive between 4,000 mm and 9,000 mm of rainfall. However, some municipalities can receive more than 11,000 mm.6 High average precipitation can also be found in the Amazonian region, between 3,000 mm and 4,000 mm.6 The Orinoco and Caribbean regions have varied rain patterns, receiving between 1,000 mm and 4,000 mm of rainfall. Meanwhile, most municipalities in the Caribbean region receive less than 1,500 mm of rainfall per year.6 The Caribbean, Andean and Orinoco regions experience dry seasons from the last months of the year until March, when the wet season begins. On the other hand, the Pacific and Amazonian regions receive precipitation throughout the year.[7]
Hydrology	The hydrology of Colombia is characterized by the presence of wide and fast-flowing rivers (Magdalena, Causa, Amazonas, Putumayo, Caquetá and Guaviare, among others). This explains the country's hydropower potential as well as its vulnerability to climate change effects.

ELECTRICITY SECTOR OVERVIEW

As of December 2020, Colombia had an installed capacity of 17,432.4 MW (Figure 1).[8] The country's electricity mix is characterized by a high reliance on hydropower, which in 2020 accounted for 68 per cent of total capacity. On the other hand, fossil fuel-powered plants accounted for approximately 30 per cent. Electricity generation in 2020 amounted to 69,323.5 GWh (Figure 2).[9] Approximately 73 per cent of the total originated from renewable energy sources, including almost 72 per cent from hydropower.

Electricity demand in 2020 was also lower than in 2019. The National Government and local authorities established total and partial lockdowns throughout 2020 due to the COVID-19 pandemic. This situation affected electricity consumption by industrial and commercial users, which resulted in a contraction of electricity demand — especially, between April and September 2020.[11]

Figure 1. **Installed Electricity Capacity by Source in Colombia in 2020 (MW)**

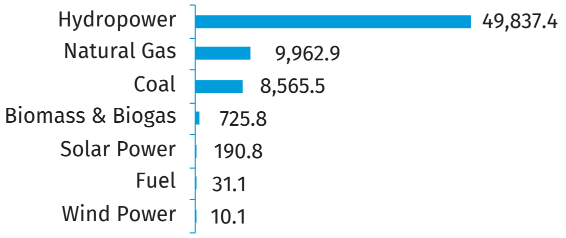


Source: XM[8]

Even though most of the electricity in 2020 was generated from hydropower, that year this source represented a smaller share of total electricity generation in comparison to 2019.[10] This was a result of declined water levels in reservoirs due to hydroclimatic conditions. Thus, between January and April 2020, the water level in reservoirs descended from 54.2

per cent to 31.8 per cent of capacity; and only by July were the reservoirs able to return to 2019 levels. The remaining electricity was generated mostly by coal and natural gas power plants.[10]

Figure 2. **Annual Electricity Generation by Source in Colombia in 2020 (GWh)**

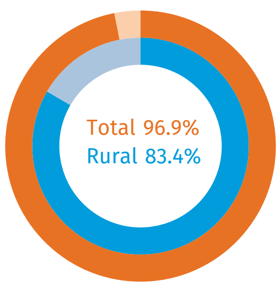


Source XM[9]

An important characteristic of the Colombian electricity sector is its integration with other countries. During 2020, Colombia exported 8.3 GWh to, and imported 42.7 GWh from, Ecuador.[12] In December 2020, the Colombian Ministry of Mines and Energy accepted the *pro tempore* presidency of the Andean Interconnection System (SINEA), a regional effort to integrate the electricity infrastructure, regulation and markets of Colombia, Ecuador, Peru, Bolivia and Chile. The country is also working on a future interconnection with Panama, which will allow the integration of the Andean and Central America markets.

In terms of electricity coverage, according to the Inter-American Development Bank's Energy Hub, the country ensured energy access to 96.9 per cent of its population in 2018 and 83.4 per cent of the rural population in 2017.[13,14] Of the population without electricity access, 97.2 per cent live in rural areas (approximately 471,000 people).[13]

Figure 3. **Electrification Rate in Colombia (%)**



Source: IADB,[13] RAP-E[14]

Note: Rural electrification data for 2017; total electrification data for 2018.

The National Government has set a goal of providing electricity to 100,000 additional households between 2018 and 2022 and, following the commitments under the Sustainable Development Goals, universal access is expected to be achieved by 2030.[15,16] This is essential for improving living conditions in the non-interconnected zones, which represent 52 per cent of the country's territory and where only 7.26 per cent of the installed capacity was renewable (21.29 MW) as of December 2020.[17,18]

The characteristics of the electricity sector of Colombia were defined in 1994 by the public utilities law (Law 142/1994) and the electricity law (Law 143/1994).[19,20] According to those laws, the electricity generation and commercialization activities are open to competition and private participation is encouraged. Therefore, during the past decades these segments have seen an increasing participation of national and foreign companies.

As a result, the main stakeholders of the electricity sector are present in both the public and private sectors. In the public sector, the Ministry of Mines and Energy sets the public policy for the electricity sector; the Energy and Mining Planning Unit (UPME) and the Energy Planning Institute for Non-Interconnected Zones (IPSE) oversee planning; the Energy and Gas Regulatory Commission (CREG) regulates the electricity market; and the Superintendency of Public Utilities enforces the said regulations. Moreover, some of the largest Colombian public and private companies belong to the energy sector, such as Enel, Empresas Públicas de Medellín, Enel Colombia, Interconexión Eléctrica (ISA) and Grupo de Energía de Bogotá. Most of these companies integrate generation, transmission, distribution or commercialization activities since the current regulations have increased flexibility in vertical integration rules.[21]

Electricity tariffs are determined by the CREG for each regional distributor, following a formula determined by CREG Resolution 91/2007. Between 2015 and 2019, average monthly prices varied between 0.07 USD/kWh and 0.12 USD/kWh, depending on the region. During 2019, the departments of Nariño and Casanare paid the highest tariffs, while Arauca and Putumayo paid the lowest tariffs.[22]

SMALL HYDROPOWER SECTOR OVERVIEW

Law 697/2001 first established a definition of small hydropower (SHP) resources (*pequeños aprovechamientos hidroenergéticos*), which limited the notion of SHP to power plants under 10 MW. Afterwards, Law 1715/2014 broadened the definition and established that SHP includes all small-scale hydropower plants of up to 20 MW.[23,24] Including power plants under 20 MW is congruent with the Colombian electric market regulation. Regardless of its source, all plants under 20 MW are considered minor plants (*plantas menores*). In Colombia, minor plants are neither subject to Central Dispatch nor used for grid balancing. Following the Colombian Hydropower Potential Atlas, adopted by the UPME, SHP can be classified into further categories of pico-, micro-, mini- and small hydropower (Table 1).[25]

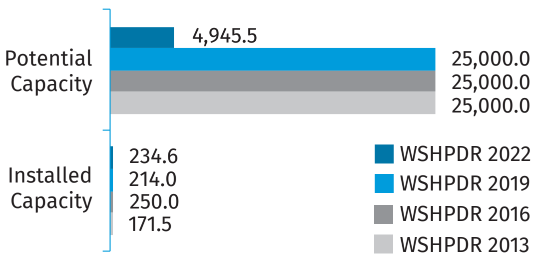
Table 1. **Classification of Small Hydropower in Colombia**

Category	*Installed capacity*
Pico	0.5 kW – 5 kW
Micro	5 kW – 50 kW
Mini	50 kW – 500 kW
Small	500 kW – 20 MW

Source: UPME[25]

As of September 2020, Colombia had 234.64 MW of installed SHP capacity for plants up to 10 MW.[26] For plants under 20 MW, the installed capacity was 900.79 MW as of December 2020.[27] In comparison to the *World Small Hydropower Development Report (WSHPDR) 2019*, the country increased by 20.64 MW its installed capacity in plants up to 10 MW.[28] The change between the data reported in the *WSHPDR 2019* and the *WSHPDR 2022* is justified by access to more accurate data (Figure 4) and new SHP capacity additions (Table 2). The potential capacity for SHP up to 10 MW is estimated at 4,946 MW, indicating a drastic change from an estimated 25,000 MW according to the *WSHPDR 2019*, which is also due to new and more accurate data.[25]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Colombia (MW)**



Source: UPME,[25] WSHPDR 2019,[28] *WSHPDR 2013*,[29] *WSHPDR 2016*[30]

Note: Data for SHP up to 10 MW.

According to the Public Registry of Generation Projects (administered by UPME), as of November 2020, 43 additional hydropower projects between 1 MW and 10 MW, representing a combined capacity of 254 MW, had been submitted for approval.[31] Of these, 23 are in the Antioquia department, 8 in the Caldas department, 3 in Tolima, 3 in Risaralda, 3 in Calle del Cauca, 2 in Norte de Santander and 1 in Cauca. These projects represent 28.7 per cent of the 887 MW of new small-scale projects in the Registry that are awaiting approval and 7.3 per cent of the 3,471 MW that represents all hydropower projects in the Registry.[31]

Table 2. **List of Selected Operational Small Hydropower Plants in Colombia**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
PCH La Libertad	Toca, Boyacá	1.20	EMPRESA GENERADORA Y COMERCIALIZADORA DE ENERGIA ELECTRICA DE COLOMBIA S.A. E.S.P.	2020
Urrao	Urrao, Antioquia	1.03	ESPACIO PRODUCTIVO S.A.S. E.S.P.	2020
Prado IV	Prado, Tolima	5.00	CELSIA COLOMBIA S.A. E.S.P.	2019
Nima	Cali, Valle del Cauca	6.70	CELSIA COLOMBIA S.A. E.S.P.	2019
Rio Cali	Cali, Valle de Cauca	1.80	CELSIA COLOMBIA S.A. E.S.P.	2019
El Cocuyo	Versalles, Valle des Cauca	0.70	CELSIA COLOMBIA S.A. E.S.P.	2019
Cantayus	Cisneros, Antioquia	4.32	GENERADORA CANTAYÚS S.A.S E.S.P	2019
Hidrobarrancas	Dabeiba, Antioquia	4.70	MARERSA JEK COLOMBIA SAS ESP	2019
Amalfi	Amalfi, Antioquia	0.81	HZ ENERGY S.A.S. E.S.P	2019
Autg Cementos Del Nare	Pto Nare, Antioquia	9.00	EMPRESAS PUBLICAS DE MEDELLIN E.S.P.	2019
Mulatos Ii	Bolombolo, Antioquia	7.34	RENOVATIO TRADING AMERICAS S.A.S. E.S.P	2019

Source: UPME[26]

Furthermore, according to UPME's Public Registry, as of November 2020, 19 new hydropower projects between 10 MW and 20 MW, representing a total of 321 MW, had been submitted for approval. Of these, 8 are in Antioquia, 2 in Tolima, 2 in Boyacá, 2 in Cauca, 1 in Norte de Santander, 1 in Risaralda, 1 in Quindío, 1 in Arauca and 1 in Cundinamarca. These projects account for 32.5 per cent of the 988 MW of all projects of the same size in the Registry and 9.2 per cent of the 3,471 MW representing all hydropower projects in the Registry.[31]

Finally, based on a 2015 study by Pontificia Universidad Javeriana, the 2015 Hydropower Potential Atlas provides an estimate of the total run-of-river hydropower potential in Colombia by region and plant size based on turbine flow, hydraulic drop and efficiency. The country's total theoretical SHP potential is estimated at 4,946 MW (Table 3).[32] Thus, approximately 4.7 per cent of identified SHP potential has been developed so far. There is currently no available data regarding SHP sites available for development or refurbishment.

Table 3. **Theoretical Small Hydropower Potential in Colombia (kW)**

Region	*Pico*	*Micro*	*Mini*	*Small*
Amazonian Region	285	2,799	26,948	903,311
Caribbean Region	210	1,935	16,843	436,476
Andean Region*	514	5,229	47,567	1,646,204
Orinoco Region	360	3,599	35,789	1,230,958
Pacific Region	165	1,647	15,984	568,657
Total	**1,553**	**15,209**	**143,132**	**4,785,606**

Source: UPME[32]

Note: *The Andean Region is referred to in the 2015 Hydropower Potential Atlas as 'Magdalena & Cauca' due to the two main rivers that cross this region.

RENEWABLE ENERGY POLICY

The promotion of renewable energy was first outlined in Law 697/2001 and recently developed by Law 1715/2014.[23,24] According to the latter, the promotion of non-conventional renewable energy is a matter of 'public utility and social interest' due to its connection to energy security, competitiveness and environmental sustainability. This status grants non-conventional renewable energy a preferential standing in several legal topics, such as urbanism, environment, administrative and procurement matters.

The most relevant dispositions contained in Law 1715/2014 relate to fiscal incentives for non-conventional renewable projects, the promotion of small-scale projects such as self-generation and distributed generation and the replacement of diesel generation in non-interconnected zones.[24] Nonetheless, most of the legal and regulatory development of Law 1715/2014 has focused on solar and wind power projects. For instance, additional fiscal incentives have been introduced to specific components of these technologies.

In 2019, the National Government committed to increasing the non-conventional renewable energy installed capacity to 1,500 MW by 2022.[33] To meet this goal, a renewable energy portfolio standard was created by Law 1955/2019 and several renewable energy auctions have been and will be organized by the Government.[34] The expected outcome of these policies is the increase of non-conventional renewable energy installed capacity to over 2,250 MW by 2022.[34]

Furthermore, Colombia is committed to transforming its energy sector to comply with its commitment under the Paris Agreement. According to its initial Nationally Determined Contribution (NDC), the country committed to reduce by 20 per cent its greenhouse gas emissions by 2030.[35] This target could increase to 30 per cent in case international cooperation is ensured. Recently, the country updated its NDC and increased its mitigation ambition by establishing a new commitment of reducing its greenhouse gas emissions by 51 per cent by 2030.[36]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

According to Law 1715/2014, SHP is considered non-conventional renewable energy. Hence, the tax benefits created for its promotion are applicable to such projects as well, which are the main incentives for these projects currently.[24] As previously stated, the said law contains a definition of SHP, which includes all small-scale hydropower plants. This is a wider definition in comparison to what was stated in Law 697/2001, which circumscribed SHP to power plants under 10 MW.[23]

Moreover, due its classification as a non-conventional renewable energy source, SHP could be financed through mechanisms applicable to this category of technologies. The financial sector's interest in renewable energy is increasing and the appearance of future financial instruments is expected in the short term. Moreover, the Government has a fund devoted to investing in renewable energy (Non-Conventional Energies and Energy Efficiency Fund, or FENOGE) whose resources could eventually be used to finance SHP projects.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The considerable hydropower potential of Colombia might become a liability due to the climate crisis. Due to the country's exposure to the crisis, negative effects are foreseen in different sectors and regions. Regarding water resources, it is expected that more than 50 per cent of the national territory will be affected by changes in the hydrologic systems.[33] These changes will vary depending on the region: some parts of the country will experience a reduction in precipitation, while others will see an increase. Overall, given the large share of hydropower in national electricity generation, this might eventually affect energy security of the country.[37]

For this reason, as a mitigation measure against the effects of the climate crisis, the Colombian energy policy is mainly focusing on promoting solar and wind power energy, as well as storage systems. This might dissuade investment in hydropower projects in the medium and long run.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The previous edition of the *WSHPDR*, identified several barriers to SHP development in Colombia, some of which are considered to persist over time.[28] The following points summarize the main barriers that have been identified:

- Substantial climatic variations may affect the reliability of hydropower;
- Efforts to reduce dependence on hydropower to increase energy security due to the mentioned climate variations;

- Preference of solar and wind power over SHP, even in non-interconnected zones;
- Deficit in research and development investments for SHP projects;
- Institutional fragility can discourage investment in SHP in non-interconnected zones;
- Lack of awareness or support on the part of the communities, especially in non-interconnected zones;
- Overvaluation of land in rural zones by landowners.

The key enablers for SHP development in Colombia are the favourable geographic and hydrological conditions.

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Ecuador

Poullette Faraon Chaul Corona, Independent Consultant

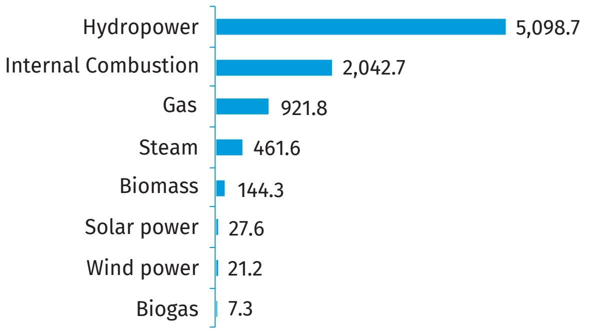
KEY FACTS

Population	17,510,643 (2020)[1]
Area	256,370 km2 [2]
Topography	Ecuador is located at the north-west part of South America, with Colombia to the north, Peru to the east and south and the Pacific Ocean to the west, where it holds an insular region, the Galapagos Islands. From north to south, the territory is crossed by the Andes Mountains (the Sierra region), which brings a diverse topography. At both sides of the Andes lie lowlands with a slightly rugged topography —the coastal region to the west and the Amazon plain to the east. The highest point of the country is Mount Chimborazo, at 6,267 metres above sea level. The country's capital, Quito, lies at an elevation of 2,850 metres.[3,4]
Climate	Given its location on the equator, Ecuador mostly has a humid tropical climate with two seasons: winter (humid) and summer (dry). The climate in the country is highly influenced by its topography, with temperature varying between 0 °C and 26 °C throughout the year. The temperatures depend on the region and elevation, with a tight inverse relationship between altitude and temperatures. The average temperature in the Galapagos Islands is 23 °C, in the coastal and Amazonian regions between 24 °C and 25 °C and in the Sierra region between 8 °C and 20 °C. The average annual temperature variation in the country is approximately 3 °C, nonetheless, the daily variations might fluctuate from 10 °C in low and coastal areas to 20 °C in the Andes Mountains.[5]
Climate Change	Studies have shown that climate change has impacted Ecuador (between 1960 and 2006) with an increase in anomalous climate events, mainly in the coastal and the Amazonian regions. There has been an increase in temperatures, their variations and rainfall, mainly in the coastal and Sierra regions. A 2021 study showed that in the last 20 years, in some areas of the coastal region, there has been an increase in rainfall, but the change in temperature has not been relevant. Regarding the Sierra and Amazonian regions, a 2021 study that analyzed the 1980-2019 period showed that, in most areas, temperature and rainfall have a decreasing tendency, however, further research is required. Hydrological systems are particularly vulnerable to changes in rainfall or droughts caused by climate change. Some areas of the coastal region are more prone to floods and droughts (Guayas and Jubones Rivers). In the Sierra region, there is more risk of landslides and erosion, and the Amazonian region might experience high risk floods (areas close to Peru). In Ecuador, a 2 °C increase in temperature is expected towards the end of the century, which could be higher in the Amazonian Region and the Galapagos islands.[6,7]
Rain Pattern	The average annual rainfall in Ecuador is 2,249 mm. High rainfall is present in the Amazonian and northern coastal regions, while it is low in the centre and southern coastal region. The coastal region presents an average annual rainfall of 400–3,000 mm, with 70–95 per cent of annual precipitation taking place between December and May. The Sierra region receives 600–3,000 mm of rainfall, with the highest precipitation in February–May and October–December. The Amazonian region receives 2,500–5,000 mm, with constant precipitation throughout the year.[8]
Hydrology	Total runoff rainwater averages 432,000 hm^3, which gives a specific annual runoff of 1,600 mm/year, exceeding the world average (of 33 mm/year). There are two main basins that absorb rainfall through a concentrated hydrographic network: the Amazon River basin, which generates approximately 70 per cent of the medium flow, and the Pacific basin, responsible for the generation of 30 per cent of the medium flow. Ecuador has 376,020 hm3 of annual water resources (361,750 hm3 surface and 56,560 hm3 underground, of which only 14,270 hm3 account for a non-repetitive volume). The average annual volume is 70,046 hm3 for the coastal region, 59,725 hm3 for the Sierra region and 246,246 hm3 for the Amazonian region. The country holds approximately 1,275 rivers and over 100 water catchment areas. Most of the rivers in Ecuador are abundant and navigable. Originated from the mountains, they drain to either the Pacific Ocean or the Amazon River.[9]

ELECTRICITY SECTOR OVERVIEW

In 2020, the total installed capacity in Ecuador was of 8,712.3 MW. By May 2021, it reached 8,725.2 MW, with renewable sources accounting for almost 61 per cent of the total capacity (hydropower, wind power, solar power, biomass and biogas) and non-renewable sources accounting for 39 per cent (internal combustion motors, gas and steam) (Figure 1).[10] The two main hydropower plants are Coca Codo Sinclair (1,500 MW), which supplies 25 per cent of the country's electricity demand, and Paute Molino (1,100 MW), which supplies 19 per cent of the demand.[11] In 2020, the installed capacity of isolated systems reached 1,372 MW, mainly in the regions of Orellana (57 per cent of the capacity) and Sucumbíos (30 per cent).[12] In addition, Ecuador holds 650 MW of installed capacity for electricity imports from Colombia (540 MW) and Peru (110 MW). Renewable energy capacity increased from 2,338.2 MW in 2011 to 5,299.1 MW in 2020, mainly due to new hydropower development. The total hydropower installed capacity went from 2,234.4 in 2011 MW to 5,098.8 MW in 2020.[13] Hence, between 2010 and 2020, renewable energy capacity more than doubled, mainly due to growth in hydropower.[14]

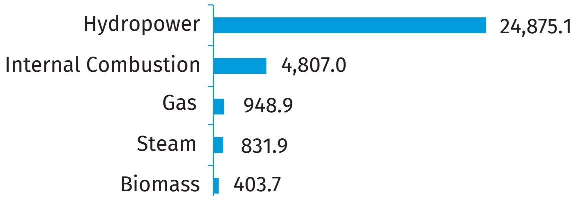
Figure 1. **Installed Electricity Capacity by Source in Ecuador in 2021 (MW)**



Source: ARCONEL[10]

National annual electricity generation reached 31,248 GWh in 2020.[12] In the period of September 2020–August 2021, electricity generation totalled 32,016 GWh (Figure 2).[10] Renewable sources (hydropower, wind power, solar power, biomass and biogas) accounted for 79 per cent of total generation, mainly through hydropower, which represented 78 per cent of the total.[10] Non-renewable sources corresponded to slightly more than 20 per cent of total electricity generation, mainly through internal combustion motors, which represented approximately 15 per cent of total generation.[10] In addition to domestic generation, during the same period, Ecuador also imported 279.7 GWh from Colombia.[10] Ecuador exported a total of 385.0 GWh to Colombia (95 per cent of total exports) and 40.8 GWh to Peru (5 per cent) during the same period.[10] In 2020, the electricity sector experienced 4,417 GWh of losses on transmission and distribution lines.[15]

Figure 2. **Annual Electricity Generation by Source in Ecuador in 2020/2021 (GWh)**



Source: ARCONEL[10]

Note: Data for the period of September 2020–August 2021.

A particularly high electricity demand was observed in Ecuador throughout 2019, having reached a historic record on 8 May (3,949.9 MW), with 91 per cent coverage from hydropower generation.[16] However, the Covid-19 pandemic had an important impact on electricity demand due to a reduction in industrial and commercial activities. By May 2020, demand started to recover again with the implementation of economic reactivation measures by the Government.[17] According to the National Electricity Operator (CENACE), the electricity demand in January–July 2021 increased by 8 per cent in comparison to 2020, due to more dynamic commercial and industrial activities.[18] Overall, between 2009 and 2019, per capita electricity consumption increased 39 per cent, reaching 1,517 kWh.[14]

In Ecuador, the power sector has regulated demand (public services) and unregulated demand (big consumers, auto-consumers and self-generators).[13] Public and private companies, duly authorized by the regulator, can generate electricity but only private ones are authorized for self-consumption. Hence, there are power plants owned by generators, self-generators (that may inject and sell surplus to the grid and distribution with generation companies (that provide public services of electricity and street lightning).[19] In December 2020, Ecuador had 139 power plants, of which 59 were private (25 hydropower, 24 solar power, 5 thermal power, 3 biomass and 2 biogas) and 80 public (40 thermal power, 39 hydropower and 1 wind power).[20] The power system is divided into two sections: the National Interconnected System (SNI), which holds most of the installed capacity, and the isolated systems, not connected to the SNI due to hard access, e.g., the Galapagos Islands and remote areas in the Amazon.[21]

The electricity sector in Ecuador is regulated by the 2008 Constitution, the 2015 Organic Law of the Public Electric Power Service (LOSPEE), its General Regulation issued in 2019, the 2019 Energy Efficiency Law, the Electricity Sector Master Plan (PME) updated every four years (the last updated version is for 2018–2027) and the National Energy Efficiency Plan (PLANEE), updated every two years. The Energy Efficiency Law regulates the National System of Energy Efficiency (SNEE) and promotes the efficient and rational use of energy as well as the service and tariffication of electric charging for vehicles. In 2017, Ecuador also issued the National Energy Efficiency Plan.[22] The electricity sector depends on the

Ministry of Energy and Non-Renewable Natural Resources (MERNNR) for the definition of policies and planning. The regulator is the Agency of Regulation and Control of Energy and Non-Renewable Natural Resources (ARC) and the electricity operator CENACE is in charge of the administration of the national interconnected grid (SNI). The Electrical Corporation of Ecuador (CELEC) is the state-owned integrated electricity company in charge of generation, transmission and import of electricity. In 2020, CELEC held most of the total installed capacity in the country at 6,366.2 MW, of which 70 per cent (4,482.2 MW) was from hydropower.[11] The National Electricity Corporation (CNEL EP) is in charge of electricity distribution and commercialization.

According to the World Bank, total electricity coverage in Ecuador in 2019 reached 100 per cent, both in urban and rural areas.[23] Nonetheless, according to ARC, in 2019, the national electrification rate was of 97 per cent, with 98 per cent expected by 2027.[24,25] Since 1999, Ecuador has a fund for rural electrification (FERUM) to increase electricity coverage in rural and remote areas.

Regulation of electricity tariffs, costs of generation, transmission, distribution and commercialization is handled by the ARC (former Agency for Regulation and Control of Electricity, ARCONEL) created in July 2020 after the merger of different regulation and control agencies. Tariffs are updated yearly observing the principles of solidarity, equity, cost coverage and energy efficiency and vary by the type of consumer (industrial, commercial and services or residential) and voltage level (low, medium, high).[26] For 2021, the total approved cost for generation, transmission and distribution of electricity was 0.09 USD/kWh. The average of differentiated tariffs applied by sector of consumers are: residential 0.10 USD/kWh, commercial 0.10 USD/kWh, industrial 0.08 USD/kWh and others 0.07 USD/kWh.[26]

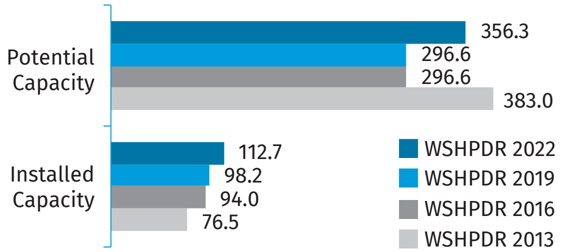
The electricity sector is subsidized, mainly for residential consumers, for example, through the "dignity tariff" and tariff incentives for the Efficient Plan for Induction Cooking and Electric Water Heating (PEC). The former is applied to 1.6 million beneficiaries and offers a reduction in tariffs for elderly people and the disabled, whereas the latter is applied to 14 per cent of households and was implemented in 2014.[11] In the last 10 years, weighted average prices of electricity have decreased from 0.04 USD/kWh in 2011 to 0.03 USD/kWh in 2020. Average prices vary depending on the type of the company: generation (0.03 USD/kWh in 2020), distribution with generation (0.04 USD/kWh in 2020) and self-generation companies (0.05 USD/kWh in 2020). Between 2011 and 2020, the highest prices were for solar power generation (0.04 USD/kWh), given that feed-in tariffs (FITs) have been in place since 2011 in order to incentivize solar power deployment.[13] In 2020, due to the Covid-19 pandemic, compensatory measures were applied, such as subsidies in favour of electricity consumers and the suspension of power cuts as well as of interests and surcharges due to the lack of payment.[27]

SMALL HYDROPOWER SECTOR OVERVIEW

In Ecuador, small hydropower (SHP) plants are considered to have up to 10 MW of capacity. Nonetheless, hydropower plants of slightly higher capacity (even up to 50 MW) are, in practice, sometimes considered as SHP. For the purpose of this chapter, the 10 MW definition will be followed.

In 2020, the installed capacity of SHP in Ecuador was 112.7 MW.[13] Total SHP potential, including developed and undeveloped potential, is estimated at 356.3 MW. The change in installed capacity since the *World Small Hydropower Development Report (WSHPDR) 2019* is due to continued growth of the sector, while the change in potential capacity is due to a new analysis, as identified in the PME (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Ecuador (MW)**



Source: ARCONEL,[11] *WSHPDR 2013*,[28] *WSHPDR 2016*,[29] *WSHPDR 2019*,30 MERNNR[31]

There are 43 SHP plants in Ecuador, including generators (19), self-generators (9) and distribution with generation companies (15), that not all inject to the grid (Table 1). SHP generation (only from generation companies) reached 267.0 GWh in 2020.[13] Two SHP plants started operations in 2020: San José de Minas (6.75 MW) and El Laurel (0.75 MW), which generated a total of 14.7 GWh in 2020.[13]

Table 1. **List of Selected Operational Small Hydropower Plants in Ecuador**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
San José de Minas	Pichincha	6.8	San José de Minas	2020
Rio Verde Chico	Tungurahua	10.0	Hidrosierra	2019
Hidrotambo	Bolívar	8.0	Hidrotambo	2016
Alazán	Cañar	6.2	CELEC-Hidroazogues	2016
Loreto	Chinchipe	2.3	Ecoluz	2002
Río Blanco	Chimborazo	3.0	E.E. Riobamba	1997
Illuchi No.2	Cotopaxi	5.2	E.E. Cotopaxi	1987
San Miguel de Car	Carchi	3.0	E.E. Norte	1987
Pasochoa	Pichincha	4.5	E.E. Quito	1976

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Ambi	Imbabura	8.0	E.E. Norte	1968
Papallacta	Napo	6.6	Ecoluz	1965
Península	Tungurahua	3.0	E.E. Ambato	1962
La Calera	Pichincha	2.5	I.M. Mejía	1957
Carlos Mora	Zamora	2.4	E.E. Sur	1957
Los Chillos	Chimborazo	1.8	E.E. Quito	1953
Illuchi No.1	Cotopaxi	4.2	E.E. Cotopaxi	1951
El Carmen	Pichincha	8.4	EPMAPS	–
Vindobona	Pichincha	6.1	Vicunha	
Perlabí	Pichincha	2.7	Perlabí	–
Planta Chimborazo	Napo	2.0	UCEM	–

Source: ACRONEL[13]

The generation expansion plan stated in the PME was updated to consider projects to be deployed between 2021 and 2024 and to be connected to the SNI. Of these projects, SHP accounts for six, with a total capacity of 42.36 MW and expected to start operations between 2021 and 2024 (Table 2).[31]

Table 2. **List of Selected Planned Small Hydropower Projects in Ecuador**

Name	*Location*	*Capacity (MW)*	*Developer*	*Planned launch year*	*Stage of development*
Chalpi Grande	Napo	7.6	EPMAPS EP	2021	In construction
Mazar-Dudas, Central San Antonio	Cañar	7.2	CELEC EP - Hidroazogues	2022	Frozen
Maravilla	Pichincha	9.0	Hidroequinoccio EP	2023	Operation approval
Mazar-Dudas, Central Dudas	Cañar	7.4	CELEC EP - Hidroazogues	2024	Frozen
Soldados Yanuncay, Central Soldados	Azuay	7.2	Elecaustro S.A.	2024	Operation approval

Source: MERNNR[31]

Ecuador has a gross theoretical hydropower potential of 91,000 MW, while technical and economically feasible potentials are estimated to be 31,000 MW and 22,000 MW, respectively.31 Hence, a considerable potential capacity remains undeveloped in the country. To use some of this hydropower potential, the PME 2018–2027 considers a total of 97 hydropower projects, for a total expected capacity of 9,429 MW. Nonetheless, SHP only accounts for 3 per cent of this total expected capacity (243.65 MW), with 47 potential projects (Table 3).[31]

Table 3. **List of Selected Small Hydropower Projects Available for Investment in Ecuador**

Name	*Location*	*Potential capacity (MW)*	*Type of site (new/refurbishment)*
Bravo Grande	Esmeraldas	10	New
Alambi	Pichincha	9.5	New
San Pedro II	Pichincha	9.5	New
San Francisco II	Azuay	9.4	New
Tandapi	Pichincha	8.9	New

Source: MERNNR[31]

Note: Data as 5of 2018.

The former ARCONEL identified that the greatest hydropower potential in Ecuador (9.93 GW) is found in the Amazon basin. However, the latest tenders seek to strengthen the development of generation in the Pacific basin (with a potential of 3.5 GW), through economically competitive projects, to reduce issues with generation imbalance, especially during the rainy season in the Amazon basin. The Pacific basin has its maximum production from January to March, when the hydropower plants from the Amazon basin have low generation.[32]

RENEWABLE ENERGY POLICY

Ecuador has shown commitment to tackling climate change and protecting nature. The country signed the United Nations Framework Convention on Climate Change in 1992 (with no mandatory commitments), the Kyoto Protocol in 1999 and the Paris Agreement in 2016. It has implemented some climate change policies, such as the National Plan for Good Living 2013–2017, which defined climate change as a national issue and stated the need for a change in the energy mix; the National Climate Change Strategy 2012–2025, setting objectives for mitigation measures and increasing capacity building (mainly hydropower); and the National Climate Change Plan 2015–2018, among others.[33] The National Climate Change Strategy 2012–2025 focuses on adaptation and mitigation measures to reduce greenhouse gas emissions and defines priority sectors that are most vulnerable to climate change, which include energy, industry, agriculture and waste.[34]

Ecuador has committed to limit emissions, deforestation and air pollution, to guarantee the rights of nature and promote environmental sustainability, including the management of water heritage, and to restructure the energy mix to achieve energy sovereignty and sustainability by increasing renewable energy capacity. By 2017, Ecuador expected to achieve 90 per cent of clean energy coming from hydropower plants and aims to reduce its emissions in the energy sector by 20–25 per cent below the business-as-usual scenario.[34] Between 2010 and 2020, CO_2 emissions in the energy sector reduced by 3 per cent, mainly due to the commission of large hydropower plants, replacing thermal power generation. In September 2021, Ecuador reiterated its commitment to an average annual reduction of 6.5 million tons of CO_2 emissions equivalent until 2025, as stated in its Intended Nationally Determined Contributions.[35]

The electricity sector in Ecuador has shifted in recent years, with the National Plan for Good Living 2013–2017, towards more renewable generation, mainly hydropower.[31] The recent renewable energy policy is aiming towards pushing the development of new technologies to improve the electricity sector, such as hydrogen generation and battery storage.[36]

The PME aims to improve and expand generation, transmission and distribution in the electricity sector, with a total investment (public and private) of USD 12,679 million, of which USD 6,150 million (49 per cent of the total) correspond to the expansion of electricity generation capacity, including USD 4,675 million for hydropower plants. In 2020, there were 39 active projects, of which 21 were for renewable energy.[31] The last adjustments to the PME were made in August 2021 by the MERNNR, aiming to expand generation capacity by 1,440 MW by 2028, to be able to cover future demand, by pushing investments (approximately USD 2,200 million) in renewable energy (490 MW of solar power, 670 MW of wind power, 150 MW of hydropower and 130 MW of biomass). It is expected that 500 MW of this additional capacity will be operational by 2024.[37] Nonetheless, most of the expected added hydropower capacity corresponds to plants with over 10 MW in capacity.[31]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

There is no particular legislation in Ecuador regarding SHP, hence, the general Ecuadorian electricity sector legislation applies to SHP. According to article 3 of the LOSPEE, hydropower plants of small capacities are considered as non-conventional renewable energy sources in Ecuador. The General Regulation for the LOSPEE defines distributed generation as small power plants that are installed close to consumption and are connected to the grid. In May 2021, ARC issued a legal framework for distributed generation, for power plants with capacity between 100 kW and 10 MW, including hydropower.[38]

COST OF SMALL HYDROPOWER DEVELOPMENT

The total average cost of hydropower generation in Ecuador is expected to grow from USD 42 million in 2018 to USD 62 million by 2027.[25] The average cost estimations include administration, operation and maintenance costs; costs associated with quality, reliability and availability; costs associated with environmental responsibility; expansion of the electricity service (distribution activity); and the variable costs required for energy production. For private generation, it also includes the remuneration of the capital base of the assets in service, through the determination of an annuity with discount rates and defined useful lives of the plants.

Some preliminary average economic estimates for SHP projects between 2015 and 2019 estimate that the average investment cost varies between 3,017 EUR/kW (3,452 USD/kW) for low-head and 2,907 EUR/kW (3,326 USD/kW) for medium- and high-head (starting from 20 metres) projects. Average operation and management costs represent 3 per cent of total investment, the average lifetime of mechanical equipment is 25 years, the cost of civil works represents an average between 40 per cent (low-head) and 50 per cent (medium- and high-head) of total investment cost and the average internal rate of return is 20 per cent.[39]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The electricity sector is considered strategic in Ecuador and it is the responsibility of the Government to plan, build and maintain electricity infrastructure, although it is also able to grant concessions to private actors to meet the country's needs. The MERNNR can grant concessions (through public tenders) for the deployment of new power capacity regarding non-conventional renewable energy, which includes SHP, following the PME. Nonetheless, hydropower plants shall be returned to the state by the end of each concession.[40] Incentives can be granted to the awarded parties. All requirements and incentives are published in each call for tenders, by block, following the PME. SHP plants can take between 20 and 40 years, depending on the plant capacity.[41]

Hydropower generation projects can be financed with public, private or mixed funds (through public-private partnerships). International organizations and agencies, such as the Interamerican Development Bank, United Nations and the French Development Agency, have also financed hydropower projects in Ecuador. Since 2000, the country has implemented FITs to support the deployment of renewable electricity capacity, which have evolved throughout the years regarding incentives and technologies. In 2014, the scheme implemented differentiated rates and became applicable to hydropower plants with capacity up to 30 MW.[39] Of the current 43 active SHP plants in Ecuador, 25 received public funding (representing 61.2 MW of the total SHP deployed capacity), 15 had private funding (48.6 MW) and 3 had mixed funding (2.8 MW).[42]

Ecuador has established a clear path towards the expansion of renewable capacity. In July 2021, the intended block of renewable projects increased from 200 MW to 500 MW, of which 150 MW are expected to be hydropower of less than 50 MW, with 30 years concessions (the First Block) and 36 months for construction.[43] In September 2021, the MERNNR announced a call for tenders to attract private investment of USD 875 million to build and operate these 500 MW of renewable energy projects, including solar power, wind power, hydropower of less than 50 MW (stated as SHP in the press release) and biomass.[44] The eight SHP projects (under 10 MW) included in this tender will account for a total of 55.35 MW (Table 4), with all of them already with definitive designs. The awarding mechanism will follow the lowest offered price. Participants to the tenders shall present warranties for USD 20,000 per MW of offered capacity and demonstrate financial and technical capacity.[31] Some incentives for private investors in new electricity generation projects include the exoneration of taxes on the outflow of foreign currency (ISD), 12-year exoneration of income tax in the national territory (8 years if the investment is in Quito or Guayaquil and 15 years if in a vulnerable region).[32]

Table 4. **List of Small Hydropower Projects Open for Tender in Ecuador as of September 2021**

Name	*Location*	*Potential capacity (MW)*
Chinambí	Carchi	9.95
Rayo 1	Cotopaxi	9.8
Chanchán	Chimborazo	9.1
San Mateo	Napo	7.3
Sardinas	Napo	6.6
Huapamala	Loja	5.2
Caluma Pasagua	Bolívar	4
Tigreurco	Bolívar	3.4

Source: Ministry of Energy and Non-Renewable Natural Resources[32]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

In Latin America, climate change has a potential to affect hydropower generation due to rising temperatures, fluctuating rainfall patterns, increased volumes of water due to melting glaciers and more constant extreme weather events. By the end of the century, these factors might cause a slight increase in the hydropower capacity factor in Ecuador, with increase in precipitation and average runoff volume.[45] In Ecuador, the coastal regions are projected to have more rainfall and the widespread flooding caused by the El Niño phenomenon is expected to increase. In the Andean region, hydropower capacity factors are projected to stay between +3 per cent and -3 per cent from the baseline.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Despite the great unexploited hydropower potential in Ecuador and the Government's policies and efforts to deploy new renewable generation capacity, there are still some challenges regarding the use of SHP. The following points summarize the main barriers that have been identified:

- Most of the planned projects to deploy hydropower capacity are focused on large-scale hydropower plants;
- Despite the identification of most hydropower potential in the Amazon basin, the development of most projects is focused in the Pacific basin to counteract generation imbalance, mainly in the rainy seasons;
- The country lacks detailed information regarding economic and technical potential of SHP, which might affect policy decisions and investment.

The following points summarize the main enablers for further SHP development:

- The recent regulation on distributed generation might boost the interest to invest in SHP projects;
- Ecuador might take advantage of the expected slight increase in hydropower capacity factor due to climate change and focus on the deployment of further SHP capacity;
- Recent tenders are showing bigger interest from the Government to seek investment in hydropower projects of up to 50 MW capacity, which might portray a bigger interest in SHP deployment in the coming years;
- The incentives considered in recent tenders for the deployment of new renewable capacity might also attract more interest to SHP projects.

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French Guiana

Alberto Tena, SEDE Consulting

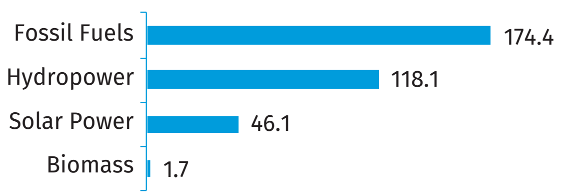
KEY FACTS

Population	281,678 (2019)[1]
Area	83,534 km2 [2]
Topography	French Guiana is situated on the north-eastern coast of South America, facing the Caribbean. The country borders Brazil to the south and east and Suriname to the west. Since 1946, it has had the status of an Overseas Department of France.3 With the exception of the coastal strip, which is made up of savannas, over 90 per cent of the country's territory is covered by rainforest. The highest peak is Bellevue de l'lnini (851 metres). Other mountains are Mont Macalou (782 metres), Pic Coudreau (711 metres) and Mont St. Marcel (635 metres). Off the coast, there are a number of small islands, including Ile de Connetable and Devil's Island located along the coast towards Brazil.[4]
Climate	French Guiana is subjected to an equatorial climate, with hot and wet weather conditions. Average temperatures vary slightly during the year, with a minimum temperature of 22 oC and a maximum temperature of up to 36 oC.[5]
Climate Change	The country is highly sensitive to climate change. Between 1955 and 2009, average temperature increased by 1.36 °C. Specifically, there is an observed increase of 1.65 °C for maximum temperatures and 1.1 °C for the average minimum temperatures.[5]
Rain Pattern	Precipitation is abundant at 3,000 mm/year, with reduced intensity in the west and the interior. There are four distinct seasons according to the pluviometry: the short rainy season lasting from the end of November to mid-February; the short summer from mid-February to the end of March; the great rainy season from April to June; and the dry season from July to mid-November.
Hydrology	There are two main rivers: the Maroni, which separates French Guiana from Suriname, and the Oyapock, located in the east and bordering Brazil for 600 kilometres. Other important rivers include the Camopi, Mana and Tompok. These are transboundary rivers and the management of their hydropower potential presupposes collaboration between the neighbouring countries.[3,6]

ELECTRICITY SECTOR OVERVIEW

Renewable energy plays an important role in electricity production in French Guiana. However, since there are difficulties with energy storage and distribution, the country still resorts to thermal power generation. The Government is focused on accelerating the energy transition and promoting sustainable energy projects, specifically, using hydropower, biomass and solar power. The total installed capacity of French Guiana in 2018 was 340.3 MW, approximately 51 per cent of which was from fossil fuels (Figure 1).[7]

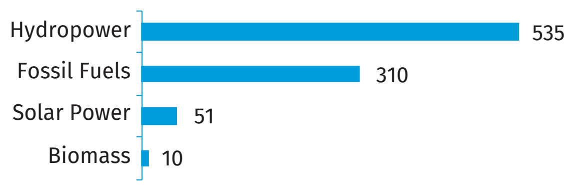
Figure 1. **Installed Electricity Capacity by Source in French Guiana in 2018 (MW)**



Source: EDF[7]

At the same time, renewable energy accounted for 66 per cent of total electricity generation in 2018, a slight reduction of 2 per cent compared to 2017.[8] This fact is linked to the conditions for hydropower electricity generation being less favourable in 2018 than the previous period. In 2018, the total production stood at 906 GWh (Figure 2), compared to 923 GWh in 2017.[7,8]

Figure 2. **Annual Electricity Generation by source in French Guiana in 2018 (GWh)**



Source: EDF[7]

French Guiana faces difficulties with supplying electricity to a large part of its territory. The littoral zone is partially interconnected by networks (except in the eastern regions), with a 414-kilometre transmission line connecting the main coastal cities of Saint-Laurent de Maroni, Kourou and Cayenne.[9] The means of electricity production for the littoral network are divided between the following power plants: the 116 MW Petit-Saut hydropower plant (EDF), which supplies on average nearly 60 per cent of the electricity consumed in French Guiana; the Dégrad des Cannes thermal power plant (EDF), which is set to be closed by 2023; the Kourou biomass power plant (Voltalia), which includes peak and back-up facilities; and other renewable energy plants, including solar photovoltaics (PV) and run-of-river hydropower.

In isolated municipalities not connected to the main grid, the means of production are limited to small electrical networks operated by EDF and supplied mainly by mini-thermal power plants and run-of-river hydropower (from the rivers Mana, Approuague, Sparouine, Maman Valentin and Inini). Almost 49 per cent of new homes built in the interior municipalities are not electrified.[10] The following municipalities are totally or partially disconnected from the electricity grid: Maripasoula, Papaïchton, Grand Santi, Saül, Saint-Georges, Camopi, Ouanary and Régina (village of Kaw).

The deficit of electric infrastructure highlights a precariousness that could be aggravated by future demographic growth.[11] Electricity demand is predicted to reach 1,280 GWh by 2030. The growing demand will have to be supplied through the construction of additional capacities, while at the same time respecting the principles established in the Multiannual Energy Programme (PPE), signed on 17 March 2017. The objective is to increase the share of renewable energy sources in electricity production to over 85 per cent by 2023.[10] However, at present, French Guiana faces important challenges in meeting this goal, since it is highly dependent on imports of fossil fuels.

Energy policies implemented by the Government are aimed at the development of modern sustainable energy infrastructure and overcoming the existing constraints, such as limited generation capacity and a lack of interconnectivity between power grids. The plans also include transmission lines to connect French Guiana to the continent's power pools and permit a large increase in interregional energy trade. The electricity transmission network of French Guiana meets the technical and economic conditions to develop such a project.

To implement energy-related policies in the territory, the local Government relies on expert entities in energy management and regulation such as the Agency for Environment and Energy Management (ADEME), Energy Regulatory Commission (CRE) and General Directorate for Territories and the Sea (DGTM). ADEME promotes and coordinates specific operations for the protection of the environment and energy management.[12] CRE is an independent authority that ensures the functioning of the electricity and gas markets in France.[13] DGTM is in charge of implementing the policies by the Ministry of the Environment, Energy and the Sea as well as those of the Ministry of Housing and Sustainable Housing.[14] The production of electricity is open to competition in French Guiana, however, according to the Law from 11 July 1975, the distribution and commercialization of electricity is monopolized by EDF.[15]

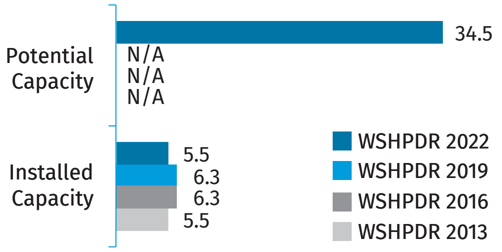
Other relevant stakeholders in the electricity sector include:
- Community of Communes of Western French Guiana (CCOG) — a public partnership entity that implements and develops rural electrification, providing specific projects for energy production (infrastructure development) as well as energy distribution (low-voltage networks);
- General Directorate of Energy and Climate (DGEC) develops and implements policies relating to energy and in particular to combating global warming and atmospheric pollution;
- French Guiana Water Office (OEG) — a public and local body in charge of water management and optimization of water as a natural resource to preserve. OEG provides studies for general interest and support for initiatives related to water treatment or energy production by hydropower systems;
- Voltalia designs and implements renewable energy projects in the country. It has carried out, among others, the hydropower project in Mana and the biomass power plant in Kourou.[16,17,18,19]

The isolation of French Guiana as an overseas territory heightens its need to produce local electricity, but at a considerable extra cost. In order to ensure that the tariffs maintain a level of equity with those of the metropole, the Government compensates the trading company EDF for these costs by means of a mechanism of tariff equalization. EDF sets different tariffs according to the power installed. For power up to 36 kV, tariffs are as follows. Tariffs for citizens range from 0.17 USD/kWh to 0.18 USD/kWh, including tax. The tariff by time slot is set at 0.20 USD/kWh, including tax, for peak hours (6 am – 10 pm) and 0.15 USD/kWh, including tax, for off-peak hours. The fixed cost for non-residential and enterprise consumers is set at 0.13 USD/kWh, excluding taxes, and the tariff by time slot is set at 0.14 USD/kWh, excluding taxes, for peak hours and 0.96 USD/kWh for off-peak hours.[20]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in French Guiana is up to 10 MW. The total installed capacity of SHP is currently 5.5 MW (Table 1).[21,22] There are two SHP plants: the Saut-Maman Valentin plant in Mana and the Saut-Maripa plant in Oyapock, which has been recently refurbished. The PPE foresees the installation of run-of-river hydropower plants on the Mana River with a combined capacity of 16.5 MW between 2016 and 2023 (Table 2).[10] However, based on the planned projects, this objective will not be achieved. According to the PPE, by 2030 the total SHP installed capacity could reach 34.5 MW.[10] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity decreased based on more accurate data and the estimate of the potential has been added (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in French Guiana (MW)**



Source: CTG,[10] Voltalia,[21] ADEME,[22] *WSHPDR 2013*,[23] *WSHPDR 2016*,[24] *WSHPDR 2019*[25]

Table 1. **List of Existing Small Hydropower Plants in French Guiana**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Saut-Maman Valenti	Mana	4.5	Run-of-river	Voltalia	2012
Saut-Maripa	Oyapock	1.0	Run-of-river	EDF	1995

Source: Voltalia,[21] ADEME[22]

Table 2. **List of Planned Small Hydropower Projects in French Guiana**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Developer*
Saut Belle-étoile	Mana	4.5	Run-of-river	Voltalia
Saut Sonelle	Maripasoula	3.2	Run-of-river	Voltalia

Source: ADEME,[22] DEAL[26]

Hydropower production in French Guiana is mainly concentrated at the Petit-Saut plant. Its production depends on climatic conditions and can vary considerably from one year to another. Nonetheless, the plant covers almost two thirds of the country's electricity needs. Its annual production fluctuated between 352 GWh in 2009 and 544 GWh in 2017, representing approximately 45 per cent and over 55 per cent of the electricity delivered to the main grid in those years, respectively. In 2018, the Petit-Saut plant produced approximately 510 GWh of electricity.[7]

SHP is foreseen to serve the main isolated towns on the Maroni and Oyapock Rivers. The 3.2 MW Saut Sonelle project on the Inini River, which is under appraisal, will supply Maripasoula and Papaïchton. There is also an ongoing study of a project on the Maroni River at Mankaba Soula, which is intended to supply the commune of Grand Santi.[22] The OEG carried out a study aimed at identifying SHP potential on the Maroni River, where many sites suitable for small-scale run-of-river project exist (Table 3).[27]

Table 3. **List of Potential Small Hydropower Projects in Mana Region**

Name	*Location*	*Potential capacity (MW)*	*Developer*	*Type of site (new/refurbishment)*
Grand Santi	Mankaba	1.00	Voltalia	New
Grand Santi	Abounami	1.00	Voltalia	New
Papaîcthon	Apanta pachi soula	0.50	Voltalia	New
Providence (Apatou)	Koumarou	0.15	Voltalia	New

Source: IFGR[27]

SHP production in French Guiana is marked by a drop in the dry season, requiring additional solar PV, diesel and storage. Furthermore, considering the particularities of the terrain and spatial location of hydropower generation, innovative solutions need to be provided in order to ensure the technical and economic feasibility of the projects. In this sense, the creation of adapted modular hydropower generation systems at low falls could solve the local constraints for energy generation. Ongoing projects and relevant studies are aimed at taking advantage of the small falls along the rivers, as demonstrated by the project at Trois Sauts, which is currently in a pilot phase.

RENEWABLE ENERGY POLICY

Favoured by a location close to the equator, French Guiana offers a large potential to utilize renewable energy in order to secure the needed energy supply. However, although the country has adopted an ecological transition policy, its dependence on fossil fuels remains problematic. In order to reduce the environmental footprint in French Guiana, policies must address the current constraints in terms of infrastructure and financial support.

Biomass energy is a priority in the national energy plans. However, the only operational biomass plant to date is the one in Kourou, as the plants in Saint Georges and Cacao will become functional once supply problems have been resolved. The PPE estimates an installed capacity of 40 MW from biomass by 2023 and current initiatives aim to achieve this potential. The solar PV sector has also emerged as one of the development priorities for the coming years. The targets set for 2030 by the PPE include 25 MW of solar PV with storage and 26 MW of solar PV without storage. However, the inherent difficulties in providing energy supply to inland areas are a constant and have prompted the creation of creative alternative solutions such as the development of small individual solar kits for small-scale consumption. Wind power is also in development, offering a suitable potential for exploitation in the littoral region.[28]

There is also a high interest to develop hydropower projects by the local Government, especially projects in the west of the territory, for example, in Mana. SHP projects adapted to the local needs exist, including the developed prototypes of river tidal turbines using river current. The potential of these installations could be important, especially to supply electricity to isolated inland regions. The available studies show a great potential for SHP development provided the development of innovative approaches to overcome the local constraints. Furthermore, the public bodies encourage local electricity production if connection to the transmission network is not possible, under satisfactory technical, economic and environmental conditions.

In its report published in February 2017, the CRE noted that production costs by energy technology are as follows:

- Petit-Saut hydropower plants — 120 USD/MWh;
- Saut Mama Valentin run-of-river plant —125 USD/MWh;
- Biomass power plant — 250 USD/MWh;
- Solar PV installations — 490 USD/MWh on average;
- Thermal power plants — 460–650 USD/MWh.[29]

The key laws regulating the energy sector in the country include:

- Law No. 2000-1207 of 13 December 2000 for the orientation for overseas territories (LOOM);
- Law No. 2005-781 of 13 July 2005 on the programme fixing the orientations of the energy policy (POPE);
- Law No. 2009-594 of 27 May 2009 for the economic development of overseas territories (LODEOM);
- Law No. 2015-992 of 17 August 2015 on energy transition for green growth (LTECV).[10]

COST OF SMALL HYDROPOWER DEVELOPMENT

The cost of electricity generation from hydropower in isolated regions, only accessible by pirogue, is estimated to be up to 1,530.8 USD/MWh, which is 5 times higher than the average production cost in French Guiana and 10 times higher than the selling price.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The Government of France has developed financial mechanisms aimed at encouraging the creation of innovative alternative solutions for renewable energy exploitation, subject to the economic viability of the projects. The public investment for the development of the hydropower sector is channelled through the French Guiana Prefecture, the French Development Agency (AFD) and the Collectivité Territoriale de Guyane (CTG), which is responsible for managing European Union funds. These entities support the developers in the preparation of their projects to ensure technical and economic feasibility and also offer financial support through such mechanisms as the allocation for infrastructure investments, provision of grants or guaranteed credits.

Additionally, other financial mechanisms for SHP include the recently launched Recovery Plan for French Guiana, a financial injection that includes the reinforcement of support for the development of renewable energy technologies.[30] The legislation of France also foresees the creation of an exceptional fund for investment in overseas territories to support the funding of projects of collective public facilities.[10]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

French Guiana is very sensitive to the climate crisis since the distribution and proportion of dry and wet seasons modify drastically the available water resources. These fluctuations are unpredictable and introduce a significant risk of supply disruption in the driest years. In order to overcome these difficulties, French Guiana opted for building thermal power plants to secure the supply, in contradiction to the plan to use 100 per cent renewable electricity production.

Hydropower plants require intelligent solutions to manage the water supply. For instance, the Petit Saut hydropower plant has an optimization system to set the water use value, which chooses the most appropriate time for using the water stored in the reservoir. In this way, its management is optimized to limit the needs for additional power requirements and to reduce the use of thermal power. This optimization system takes into account the great interannual variability of hydraulic inputs, knowing that between dry and wet years the production of the Petit Saut plant can vary by a factor of two (from 280 GWh in a dry year to 540 GWh in a wet year).[7]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The barriers to SHP development in French Guiana are as follows:

- French Guiana is highly sensitive to climate change, due to the variability of rainfall between the rainy and dry seasons;
- The development of other renewable energy sources, such as solar PV or biomass, is a priority, although numerous plans and studies to develop the SHP sector exist, especially in the east of the country;
- The remoteness of the transmission or distribution network and the environmental impacts of the projects are critical obstacles, especially in isolated areas where difficulties associated with transporting materials should be considered;
- The cost of energy production in French Guiana is considerably higher than in metropolitan France;
- There are administrative delays to obtain permissions to build electrical installations.

The enablers for further SHP development are:

- The planned closure of the Dégrad-des-Cannes thermal power plant favours the use of renewable energy sources, including SHP, to meet the country's energy demand;
- Great potential for SHP development given the variety

of suitable sites across the territory;
- Local policies favourable to the exploitation of SHP for the energy transition.

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Guyana

Tobias Dertmann, Hydropower Consultant; and International Centre for Small Hydro Power (ICSHP)

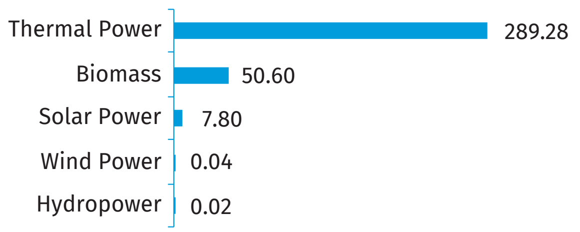
KEY FACTS

Population	743,699 (2019)[1]
Area	214,999 km2 [2]
Topography	The terrain of Guyana is mainly characterized by tropical rainforest with flat areas at the coastline and some mountainous areas in the so-called Hinterland. The Pakaraima Mountains in the west rise to 2,772 metres at Mount Roraima, which is the highest point of the country.[2,3]
Climate	The climate is tropical, characterized by high temperatures and humidity. Temperatures average 25 °C with little variation throughout the year.[3]
Climate Change	The main impacts of climate change in Guyana include: increases of heavy rainfall, possibly leading to flooding; longer periods of draught; sea level rise and storm surges, especially in coastal zones; and increases in temperature and decrease of annual precipitation. It is expected that temperatures will increase by 1-4 °C in the country by the end of the century, while sea levels will rise by 0.3-0.9 metres.[4]
Rain Pattern	Precipitation is generally high, ranging from 1,500 mm to over 4,000 mm, with a pronounced rainy season from May to July and a shorter one from December to January.[3]
Hydrology	Guyana is called the Land of Many Waters owing to the abundance of streams, rivers and creeks. The largest waterways are the Corentyne, Berbice, Essequibo and Demerara Rivers. Particularly in the relatively unpopulated southern part of the country, there are many falls along the rivers while the rivers' gradients decrease towards the more densely populated areas at the coastline.[3]

ELECTRICITY SECTOR OVERVIEW

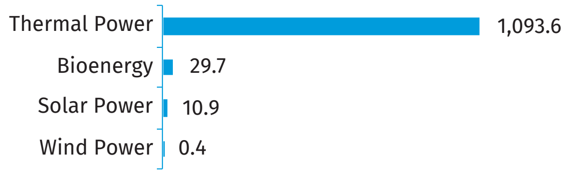
The electricity system of Guyana consists of an integrated network at the coast, which supplies electricity to approximately 90 per cent of the population, various clustered island systems in Region 3 (Essequibo Islands–West Demerara), six Hinterland island grids and self-generators, which supply individual smaller communities and mines. Installed capacity in Guyana reached a total of 347.7 MW in 2018 and renewable sources made up almost 17 per cent of the total (Figure 1).[5] Total electricity generation in 2019 stood at 1,134 GWh, with thermal power having surpassed any other source, at 1,094 GWh (Figure 2).

Figure 1. **Installed Electricity Capacity by Source in Guyana in 2018 (MW)**



Source: ETI[5]

Figure 2. **Annual Electricity Generation by Source in Guyana in 2019 (GWh)**

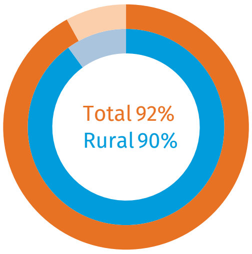


Source: GEA,[6] Guyana Chronicle[7]

While the electrification rate at the coast is high, most of the Hinterland communities do not have a regular electricity supply. In 2019 the nationwide electrification rate stood at 92 per cent, including 97 per cent in urban areas and 92 per cent in rural areas (Figure 3).[8]

The country's primary electricity utility is Guyana Power and Light Inc. (GPL), a wholly state-owned, vertically integrated utility company whose licence will expire in 2024. In many smaller Hinterland communities such as Lethem, Mahdia and others, state-owned electricity companies supply electricity to public institutions and households. In some cases, it is provided on a 24-hour basis and in others for several hours per day only. In the Hinterland electricity systems, various private electricity providers are established, foremost in conjunction with mining operations that supply the nearby communities with electricity.

Figure 3. **Electrification Rate in Guyana in 2019 (%)**



Source: World Bank[8]

Electricity is mainly produced with diesel and heavy fuel oil (HFO) generators, with the exception of a small share of co-generation from bagasse and both on-grid and off-grid solar power systems and limited contributions from hydropower and wind. In 2020, GPL demand from its customers in the coastal area was forecasted at 926 GWh.[9]

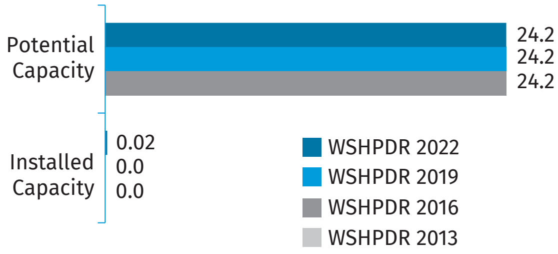
The Public Utilities Commission (PUC) regulates the electricity sector. The National Energy Policy and the Electricity Sector Reform Act (with 2010 amendments) provide the platform for the participation of independent power producers (IPPs). The Guyana Energy Agency (GEA) is mandated to advise the Minister with the responsibility for electricity and energy on matters related to energy, execute studies, formulate energy policies and regulate the import of petroleum products. However, GEA has no general role as an electricity or energy sector regulator. Besides GEA, there is the Hinterland Electrification Company Inc. (HECI), which is attached to the Office of the Prime Minister and is responsible for the electrification of the Hinterland communities. The office of the Minister with responsibility for energy, currently the Prime Minister, issues licences for IPPs or electric utilities.

GPL's electricity tariff rates for residential, commercial and industrial consumers are USD 0.22, USD 0.32 and USD 0.29 per kWh on average, respectively. Rates in the Hinterland systems are higher with the generation cost reaching as high as USD 0.50/kWh. Current electricity tariffs are by far not cost-reflective and the Government subsidizes Hinterland and GPL's operations when fuel prices are high.[9] The Government of Guyana is currently working on the 165 MW Amaila Falls hydropower project, which will significantly aid in the reduction of the overall cost of generation, and by extension, reduce electricity tariffs. The project will also improve the technical stability of the power grid with an energy mix that will include intermittent renewable energy sources.[9]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) used by Guyana applies to capacities up to 5 MW. The potential capacity for SHP is estimated to be 24.2 MW for the 5 MW threshold and 92 MW for the 10 MW threshold. Installed capacity was 0.02 MW as of 2021. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the potential capacity remained unchanged, and the installed capacity has increased due to a newly commissioned plant (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2016/2019/2022 in Guyana (MW)**



Source: Guyana Chronicle,[7] *WSHPDR 2016*,[10] *WSHPDR 2019*[11]

Note: Data for SHP up to 5 MW.

In 2019, a new SHP plant (Hosororo) was assessed and built (Table 1). This comes several years after the shutdown of the 500 kW Moco-Moco hydropower plant in 2003, following damages caused by a landslide. The Hosororo project was technically and financially supported by the German Development Agency (GIZ) and developed by GEA. It has an installed capacity of 20 kW and is connected to the small local distribution network, feeding into the electrical grid of the Mabaruma Power Company. The gross head is approximately 32 metres. The inlet structure is connected to the turbine house via a 300-metre-long pipeline. As the first hydropower plant to be restarted after more than 20 years, the project also serves as a signal to the whole hydropower sector in the country to increase the ambition within the responsible institutions.[6]

The planning, construction and commissioning for the Hosororo plant was carried out by the GEA. The project is considered as a capacity building project to increase the training of local hydropower engineers and a potential training and testing hub for the entire Caribbean (CARICOM) region. With the construction of the plant, other hydropower projects in the country have been accelerated in development (Table 2). Nevertheless, continuous operation and grid feeding into the local supply network has already taken place in the test phase and is to be operated on an ongoing basis.

Table 1. **List of Operational Small Hydropower Plants in Guyana**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Hosororo	Mabaruma	0.17	32	Run-of-river	Mabaruma Power Company	2019

Source: Guyana Chronicle[7]

The Islamic development bank (IsDB) is financing the rehabilitation of the Moco-Moco hydropower plant (700 kW) and a new construction of the Kumu (1.5 MW) plant. The tender for the double project was planned to be launched in 2021. The project will be integrated into the Lethem Power Company's electrical system. The fast-growing border town in the south-west of the country aims to generate 100 per cent of its electricity from renewable sources in the near future. The two hydropower projects will play a key role in achieving this goal.[12]

The 0.5 MW (2 x 0.25 MW) Moco-Moco hydropower project, located in Region 9, was first commissioned on 22 November 1999. The hydropower plant was designed and built by the Institute of Water Conservancy and Hydropower (Shijiazhuang, China) through a joint arrangement between the Governments of Guyana and China. The Moco-Moco plant is a run-of-river, diversion-type with a high-water head. It supplied power to the community of Lethem and its environs. However, severe rainstorms and the subsequent landslide in 2003 resulted in a fractured penstock. The Government has since been actively discussing options for its restoration. A geotechnical survey to inform the project design and assist in de-risking the project was expected to be completed in 2021.

The current concept of the project is to rehabilitate the defunct hydropower plant and increase the installed capacity to 0.7 MW. The site is located on the Moco-Moco Creek, which is a part of the Amazon River system originating from the north of the Kanuku Ranges and converging into the Takutu River. The project will provide electricity to Lethem and its environs and will form a complementary suite of planned energy initiatives in the town, consisting of the hydropower plant and a solar photovoltaic (PV) installation.

The proposed Kumu hydropower project entails the installation of a 1.5 MW plant and construction of a transmission line.[13] The Kumu Creek, located in Region 9 (Upper Takutu–Upper Essequibo), is also part of the Amazon River system. The Kumu site is situated 9.5 kilometres away from the Moco-Moco plant and 13 kilometres south-east of the town of Lethem. The project will operate as a run-of- river plant with an ultra-high head potential of more than 500 metres. Its topographical specifications can accommodate the construction of a small reservoir on the top of the mountain plateau to maintain a constant water level for operation of the plant. The combined operation of the Kumu and Moco-Moco hydropower plants, together with the planned solar PV installation, could result in 100 per cent renewable electricity generation in Lethem.

Studies have estimated the potential capacity at selected sites, such as Eclipse Falls (3–5 MW) and Tumatumari (1.5 MW). Tumatumari, utilizing water from the Tumatumari Falls on the Potaro River, Region 8, was constructed in 1957 by British Guiana Goldfields Limited and operated until 1959 when mining operations ceased. In 1969, the Government of Guyana recommissioned the plant to serve the Guyana National Service Camps at Tumatumari and Konawaruk. The development included an embankment dam, a concrete overflow dam and a two-unit powerhouse with an installed capacity of 1,500 kW using two 750 kW Francis turbines.[16]

Table 2. **List of Planned Small Hydropower Projects in Guyana**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Developer*	*Planned launch year*	*Stage of development*
Kumu	Kumu River, Region 9	1.50	550	Run-of-river	GEA	2024	Tender
Moco-Moco	Region 9	0.70	210	Run-of-river	GEA	2024	Tender
Kato New Build	Kato, Region 8	0.15	35	Run-of-river	GEA	2021	Construction
Tumatumari	El Paso, Region 8	2.20	–	Run-of-river	Unknown private company	–	Planning / rehabilitation
Ikuribisi	Region 7	1.00	–	Run-of-river	GEA	–	Planning

Source: Department of Public information,[14] I News Guyana[15]

In continuing efforts to collect data on potential hydropower sites for future development, hydrological data collection continued at Paruima, Region 7. A technical assessment was conducted at Chenapau, Region 8, to explore the possibility of developing a pico-hydropower plant.[16] Some SHP projects available for investment are listed in Table 3.

Table 3. **List of Small Hydropower Projects Available for Investment in Guyana**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/refurbishment)*
Semang	Marapaikru River	5.0	69	New
Kaburi	Kaburi River	5.0	62	New
Maparri	Maparri River	4.0	544	New
Wamakaru	Wamakaru River	2.5	215	New
Eclipse Falls	Barima River	3–5	7	New

Source: Dertmann[16]

RENEWABLE ENERGY POLICY

In order to preserve the country's rich fauna and flora, each new project must be scrutinized for ecological compatibility. Environmentally-friendly projects, however, are welcomed and have good chances of being approved. The Environmental Protection Agency provides basic requirements for acquiring environmental authorization for hydropower project developments. However, this is the country's first experience of setting rules for environmental evaluation and further elaboration thereof will be required. Currently, the Government prepares to attract developers of SHP projects by means of public tendering processes for selected projects.

The procurement process follows the following steps: approval of tender documents, advertisement and purchase of tender, submission of bidding documents, evaluation, approval of the evaluation report, contract award, execution, monitoring and evaluation, defects liability period and project closure. The Public-Private Partnership (PPP) Policy Framework was developed in 2018 for infrastructure projects including hydropower plants and other renewable energy projects. The details of the PPP process have not been put into practice yet for hydropower plants and energy farms.

The National Energy Policy of Guyana of 1994 contains an outlook from 1994 to 2004.[17] In 1994, the policy already prescribed energy conservation and a preference for domestic energy sources over imported fuels. The 1994 policy was outdated and required updating considering the latest technological and other developments. The Low Carbon Development Strategy (2013) aims to introduce climate smart infrastructure and the use of clean energy, installation of energy efficiency and conservation technologies as well as rural electrification programmes.[18] The National Energy Policy was updated in the form of a Green Paper in 2017.[19] Presently, the Government of Guyana aims to provide affordable, stable and reliable energy to benefit both households and businesses and will pursue a programme with an energy mix that includes hydropower, natural gas, solar and wind power. This programme will lead to more than 400 MW of newly installed capacity for residential and commercial users over the next five years and a reduction in the cost of energy by at least 50 per cent. There are currently no feed-in tariffs for electricity generated from renewable energy sources but this remains a priority.

The Electricity Sector Reform Act (ESRA) of 1999 mentions the use of renewable and alternative energy but does not explicitly promote the use thereof by creating preferences or other incentives.[5,15] Nonetheless, a study was conducted on the legal and regulatory framework of the electricity sector with a view to facilitate private sector investment in renewable energy development through IPPs and distributed generation. The study has proposed amendments to the ESRA and other relevant laws.

In the past, there was no structured approach to developing the country's hydropower resources. Instead of taking a proactive role in developing the resources by tendering concessions or generation capacity portfolios, the Government responded to proposals brought forward on the initiative of individual developers. The current approach to public tendering of projects outlines rules for participants in the bidding process. In 2016, the Cabinet issued instructions to invite proposals from interested groups for renewable energy projects supply in the Bartica community, Lethem (Moco-Moco) and other identified communities.[20] However, alternative funding sources were subsequently secured and the projects in these communities are now being developed through engineering, procurement and construction (EPC) contracts.

Due to the inexperience and lack of precedence in the development and operationalization of hydropower plants in Guyana, potential developers see themselves confronted with obscure processes for obtaining the various licences and meeting the rules for the application and project development process. This applies to planning licences, operating licences, environmental permits and any other applicable permits. This results in uncertainty for developers regarding the application duration, application cost and likely outcomes. Developers typically put forward high expectations regarding revenue and payback time, which the projects are rarely able to satisfy. On the other hand, the Government did not grant sovereign guarantees for such projects in the past, which, if done, would make it easier and cheaper for developers to mobilize financing. Here, both parties need to seriously consider the advantages and disadvantages of initiatives to de-risk such hydropower projects. The Government of Guyana has also introduced an online platform for investors.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The National Energy Policy of 1994 speaks of SHP in the capacity range between 500 kW and 5,000 kW. Currently, hydropower initiatives are considered and supported by the Government.[21] The Guyana Power Sector Policy and Implementation Strategy was passed by the Cabinet in 2010 outlining the way forward for hydropower development.[22] Additionally, the Low Carbon Development Strategy (2013) included the Amaila Falls hydropower project as a major part of the country's renewable energy transition.

Country-specific estimates on the cost of SHP are not yet available due to the statistically insignificant number of operational projects in the country.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Value-added tax and import duty exemptions are applied to machinery and equipment for obtaining, generating and utilizing energy from renewable energy sources, including solar panels, solar lamps, deep-cycle batteries, solar generators, solar water heaters, solar cookers, direct current (DC) solar refrigerators, DC solar freezers, DC solar air conditioners, wind turbines, water turbines and power inverters. There is also a one-off tax holiday of two years for corporation tax applicable to importers of items for wind and solar energy investments. Moreover, investments (with the exception of wind and solar power) may also benefit from exemptions from property, corporate, withholding and capital gain taxes at the discretion of the Minister of Finance for periods of five or more years depending on the type of new employment created.[23]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Due to the general extremely high annual tropical precipitation amounts, there is no significant impact of the climate crisis on the operation and planning of hydropower plants. Different climate models offer different estimates of the changes in precipitation amounts. Locally, both increases and decreases in total precipitation amounts are expected. The projected change in precipitation amounts is on average approximately 100 mm/year.[4] This corresponds to a change of approximately 4 per cent per year. The possible impact on the hydropower systems can therefore be classified as low in Guyana.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Guyana has an outstanding and yet unexplored hydropower potential, including a great number of SHP sites throughout the country that remain completely undiscovered. The Hosororo SHP plant built in 2019 was the first milestone for the further development of hydropower in the country. Since then, more projects have been launched and many more are to follow. After decades of stagnation, many new competencies in hydropower have been achieved in recent years. However, there are more hurdles ahead to further incentivize developers and investors. The country's vast hydropower potential needs strong de-risking efforts aimed at improving the attractiveness of hydropower projects, possibly bundling several projects together to channel development to a successful outcome.

The following points summarize the main barriers that have been identified:

- The great distances between hydropower sites and load centres and the difficult access into the Hinterland;
- In most cases, the construction of expensive access roads has to be included into the project budget jeopardizing the viability of projects;
- Long transmission lines between project sites and load centres put a significant financial burden on the projects, particularly considering the ratio between line length and the power demand;
- Lack of technical expertise in undertaking hydropower projects among local agencies and contractors.
- Hinterland villages face the problem of clustered settlements with large distances among villages and even individual houses resulting in high cost for connection of households to the electricity supply;
- Quantity and quality of hydrological and meteorological data to support hydropower development;
- Access and understanding of suitable software and satellite data for the generation of hydrological models to support hydropower development;
- Poorly gauged or ungauged rivers for the collection of physical data (flow, water level, rainfall, etc.)[8]

The following points summarize the main enablers that have been identified:

- Guyana has nearly four times its per capita economic output since 1990, triggering the development of internal hydropower capacities after years of stagnation in the past;
- the commitment of individual decision-makers in the country has meant that, despite major hurdles, the first (after 20 years) small hydropower station was able to start operating in 2019;
- Increased investment flows in SHP projects from the GEA in recent years.

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Paraguay

Laura Stamm, International Center on Small Hydro Power (ICSHP)

KEY FACTS

Population	7,132,530 (2020)[1]
Area	406,752 km2 [2]
Topography	Approximately two thirds of the country is covered by the Gran Chaco, a flat tropical region extending north-west into Bolivia and Argentina. Separated by the central Paraguay River, the Paraná Plateau in the eastern region is an extension of the Brazilian Plateau and varies in elevation from 50 metres to 760 metres. The Amambaí Mountains run along the border with Brazil, then turn and run eastwards as the Mbaracayú Mountains. The country's highest peak, Mount San Rafael at 850 metres, is located in the Cordillera de San Rafael in the south-east.[2]
Climate	The climate is tropical in the north-western Chaco region and subtropical in the south-eastern Paraneña region. The winter season lasts from May to August, with July being the coldest month. Temperatures typically remain between 16 °C and 24 °C, but near freezing temperatures accompanied with frost will occasionally occur. The summer season lasts from October to March, with January being the warmest month. Daytime temperatures reaching 38 °C are common. Summer is also the wetter season with increased humidity and rainfalls.[2]
Climate Change	Climate change is expected to largely affect the precipitation pattern in the country. While the drier El Chaco region in the west will most likely experience an increase in droughts, the wetter Paraneña region in the east expects an increase in floods. Average temperatures are expected to increase by between 2.6 °C and 4.8 °C by the end of the century, depending on human acitivity.[3]
Rain Pattern	There are regional and seasonal variations in rainfall. The eastern region receives the most rainfall with an average of 1,650 mm per year. The western region is considerably drier, receiving an average of 760 mm per year. Throughout the country, rainfall is heaviest between October and April.[2]
Hydrology	The Paraguay and Paraná Rivers are the two main watercourses in the country. They define most of the borders and their basins provide all of the drainage. The Paraguay River runs from north to south, splitting the country into its two major regions. The major tributaries entering the Paraguay River from the east are the Apa, Aquidabán, Ypané, Jejuí Guazú and Tebicuary Rivers. The Paraná River outlines the country's eastern and southern borders. The major tributaries are the Acaray and Piratiy Rivers. The country has two major lakes, Lake Ypoá and Lake Ypacaraí; both are situated towards the south.[2]

ELECTRICITY SECTOR OVERVIEW

Paraguay is a country with abundant energy resources, particularly hydropower, and has one of the world's highest electricity generation rates per capita (approximately 6,500 kWh).[4] In 2020, total electricity generation in the country was 46,373 GWh; 46,371.1 GWh of which was from hydropower and the remaining 1.9 GWh from thermal power (Figure 1). Of the total generated, 28,004 GWh, or 60 per cent, was exported, primarily to Brazil and Argentina. The total electricity consumed in Paraguay in 2020 was 13,719 GWh, of which 47 per cent was used by the residential sector, 49 per cent was used by the industrial and commercial sectors and 4 per cent was used for public street lighting. Losses accounted for the remaining over 4,000 GWh of electricity.[5]

Figure 1. **Annual Electricity Generation by Source in Paraguay in 2020 (GWh)**

Source: VMME[5]

The total installed capacity of Paraguay is approximately 8,816 MW (Figure 2). Most of the capacity comes from two binationally operated hydropower plants (HPPs). The Itaipú HPP, jointly operated with Brazil, provides 7,000 MW to Paraguay and a further 1,600 MW are from the Yacyretá HPP, jointly owned with Argentina. There is also the 210 MW Acaray HPP, which is solely Paraguayan owned.[4] Ongoing projects to connect all remote areas to the hydropower network have resulted in the recent closing of almost all thermal power generation, with the exception of 6.1 MW remaining in El Chaco region.[6] In 2019, the country reached a 100 per cent electrification rate, including all rural areas.[7]

Figure 2. **Installed Electricity Capacity by Source in Paraguay in 2020 (MW)**

Source: VMME[4]

While the electricity sector in Paraguay is virtually 100 per cent sourced from hydropower, the total energy production mix including energy used for transportation or industrial processes also features a significant amount of biomass. In 2020, 53 per cent of total energy produced was from hydropower and 47 per cent from biomass. Any petroleum-derived energy used in the transportation and industry sectors was all imported.[8]

The Vice Ministry of Mines and Energy (VMME), created in 1990, is the governmental body that oversees the energy sector as a whole. The National Administration of Electricity (ANDE) is a state-owned utility that controls the electricity subsector, including generation, transmission and distribution. ANDE is responsible for operating the share of Paraguay in the binational HPPs and fully runs the Acaray HPP. ANDE operates the bulk of the transmission and distribution network, but there are also some small, private distributors connected to the national grid, such as CLYFSA and COOPERATIVA MENONITA.[4,8]

The tariffs for the electricity sector are determined by ANDE, as per Law 2199/03, and vary depending on the type and volume of consumption (Table 1).[9] The Social Rate of Electricity Law 3480/2008 stipulates that people of a lower income level who fulfil certain requirements can pay the discounted, social tariff. This provides a 75 per cent discount for users of under 100 kWh per month, 50 per cent discount for users of between 101 kWh and 200 kWh and a 25 per cent discount for users of between 201 kWh and 300 kWh.[10]

Table 1. **Electricity tariffs in Paraguay**

Type	*Average tariff (USD/kWh)*
Residential	0.059
Industrial	0.043
Government	0.052
Street lights	0.055
Other	0.052
Export	0.120

Source: ANDE[9]

The electricity system of Paraguay is prone to high system losses, frequent blackouts and shortages during inclement weather, which can negatively affect commercial activities in the country. The two HPPs that supply most of the power for the whole country are both located on the eastern and southern national borders and are therefore far from the central, western and northern regions. Due to limited capacity on the insufficiently developed transmission and distribution network, efficient transfer of the energy is a challenge, resulting in the losses and shortages.[11]

At the same time, the demand for electricity is expected to grow both in Paraguay and the neighbour countries it exports hydropower to. In order to increase the efficiency of the current network and satisfy the demand increase, a 2021–2030 Works Master Plan was created. In this plan, several projects that will modernize the transmission system were outlined. Included is the construction of new transmission lines, some more than 200 kilometres in length. The total cost is expected to be more than USD 126 million.[12]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Paraguay is up to 50 MW. As of 2021, there were no SHP plants in operation. While total SHP potential is unknown, based on the projects planned to be completed by 2036, it is possible to conclude that there is at least 116.3 MW of undeveloped potential.[13] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, both installed and potential SHP capacity remained unchanged since none of the planned projects have been completed during these years (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2016/2019/2022 in Paraguay (MW)**

Sources: ANDE,[13] *WSHPDR 2019*,[14] *WSHPDR 2016*[15]

Paraguay has an outstanding hydropower potential estimated at 130 TWh annually, while technical and economically feasible potential is estimated at 101 TWh annually, which greatly exceeds the country's current installed capacity.[14] Under the 2021–2040 Generation Master Plan released by ANDE in February of 2021, the construction of several SHP plants is foreseen in order to increase the energy stability as well as offer economic opportunities in remote areas. With the completion of these smaller, more spatially spread-out plants it is hoped that losses and shortages will significantly decrease along with the reliance on the three existing hydropower plants. There are plans to install 18 SHP plants between 2029 and 2036 with a combined capacity of 116.3 MW (Table 2).[13] All of these 18 plants will feature two turbines, with each turbine having half of the total capacity listed for the plant.

Table 2. **List of Planned Small Hydropower Projects in Paraguay**

Name	*Capacity (MW)*	*Planned year of completion*
Ypané 1	3.2	2029
Ypané 2	4.2	2029
Ypané 3	4.2	2029
Ypané 4	4.3	2029
Ypané 5	5.0	2029
Ñacunday 1	8.0	2031
Ñacunday 2	4.3	2031
Carapá 1	19.0	2032
Carapá 2	4.3	2032
Itambey	5.0	2032
Jejui 1	7.0	2034
Jejui 2	10.0	2034
Jejui 3	5.4	2034
Tembey 1	3.6	2035
Tembey 2	11.0	2035
Tembey 3	3.6	2035
Pirajui	8.6	2035
Capiibary	5.6	2036
Total	**116.3**	

Source: ANDE[13]

RENEWABLE ENERGY POLICY

The National Climate Change Mitigation Plan of 2017 and the Generation Master Plan 2021–2040 both stress the importance of expanding and diversifying renewable energy. While the country produces a negligible amount of non-renewable energy, only two sources of renewable energy are developed: large hydropower and biomass. It is anticipated that diversifying into SHP and solar power will help energy stability and economic development in the country. Investments in solar photovoltaics in the western Chaco region have already begun, as well as the designation of sites for the planned SHP projects. Although the Government of Paraguay was originally interested in expanding into wind energy, various international scientific organizations found that given the topography, there is no significant potential in wind power.[13,16]

To encourage the diversification of renewable energy, the Senate passed a bill in November 2021 on Regulating the Promotion, Generation, Production, Development and Use of Electrical Energy from Non-conventional Non-hydraulic Renewable Energy Sources. The bill suggests the promotion of investment in renewable energy besides large hydropower, especially from foreign entities. It also provides the institutional framework for licensing projects above 1 MW, which the VMME would have the authority over. Additionally, it suggests financial incentives to be put in place, such as exemption from the value-added tax amongst others.[17]

ANDE was the monopoly controller of the electricity market until 2006, when Law 3009/2006 was adopted. The law opened the market to independent power producers (IPPs) to generate and transport electricity for domestic consumption or export. The law applies to all renewable energy resources with the exception of hydropower plants larger than 2 MW, in which case ANDE maintains its preferential rights.[17]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Hydropower development projects are subject to Law 294/1993, which states that any new infrastructure development, including any hydraulic works projects, must have an environmental impact assessment approved by the Secretary of the Environment before construction.[18] Specifically regarding the water supply of a project, Law 3239/2007 on Water Resources of Paraguay requires an inventory of water resources to be carried out, as well as an approved permit for its use.[13]

COSTS OF SMALL HYDROPOWER DEVELOPMENT

With no previously existing SHP plants in Paraguay, the costs associated with developing a new project can only be estimated. The Master Generation Plan predicts an investment of approximately USD 2,500 per kW for SHP projects. The plan is to invest a total of USD 505 million to complete all 18 planned projects by 2036. The cost for the projects individually is unavailable.[13]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Paraguay has a great potential for both large and small hydropower. However, the development of SHP is particularly hindered by the institutional structure and the market conditions of the country's electricity sector, namely:

- Lack of incentives for ANDE to alter the current model of operation of the electricity system and the generation of electricity;
- Insufficient demand to incentivize IPPs to enter the market;
- New policies are focused on promoting non-hydraulic sources of renewable energy.[14,16]

Some enablers to SHP development in Paraguay include:

- The untapped potential of hydropower in the country, including on smaller rivers, is significant;
- With energy stability and transmission losses being a major concern, SHP located closer to consumers could help alleviate this problem.[13]

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Peru

Julio Montenegro-Gambini and Frank Charlez Ramírez Bogovich, Wasser World Ltd.

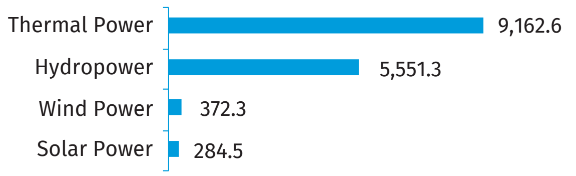
KEY FACTS

Population	32,971,846 (est. 2020)[1]
Area	1,285,215.6 km2 [2]
Topography	Peru is divided into three topographical regions: the Pacific coast, the Andean highlands (known as La Sierra) and the Amazon rainforest. Elevation ranges from 0 metres along the coast to 6,768 metres in the highlands.[3]
Climate	Peru has 28 of the world's 32 climates, a diversity created by the presence of the Andes Mountains, the cold Humboldt Current and El Niño. Temperatures vary from below 0 °C to 40 °C. Average annual temperatures are 18–20 °C on the coast, 8–11 °C in the highlands and 24 °C in the Amazon region.[3]
Climate Change	By the second half of the 21st century, climate change scenarios show an average nationwide increase in minimum temperatures of between 2 °C and 3 °C and an increase in maximum temperatures of between 4 °C and 6 °C, relative to the period 1971–2000. Precipitation is projected to increase by 10–20 per cent.[4]
Rain Pattern	Annual precipitation in Peru ranges from less than 20 mm to more than 8,000 mm. The Pacific coast is an arid region. However, during El Niño episodes the northern coast can face major flooding with precipitations higher than 4,000 mm. On the central and southern coasts, rainfall is scarce with a total range between 10 mm and 150 mm.[3]
Hydrology	The rivers of Peru are divided into three large basins: the Atlantic basin that covers almost 75 per cent of the territory of Peru and contains almost 98 per cent of the country's water resources; the Pacific basin, covering almost 22 per cent of the territory and containing approximately 2 per cent of the water resources; and the closed Lake Titicaca basin, covering less than 4 per cent of the territory and containing less than 1 per cent of the water resources. The main rivers of Peru are the Amazon, Madre de Dios, Putumayo, Napo, Maranon, Huallaga, Santa and Apurimac.[2,3]

ELECTRICITY SECTOR OVERVIEW

Total installed electricity capacity in Peru was 15,370.7 MW in 2020. Of this total, 9,162.6 MW (approximately 60 per cent) was provided by thermal power (including both renewable and non-renewable sources), 5,551.3 MW (36 per cent) by hydropower, 372.3 MW (2 per cent) by wind power and 284.4 MW (2 per cent) by solar power (Figure 1). Total available capacity the same year was 14,562.7 MW.[5]

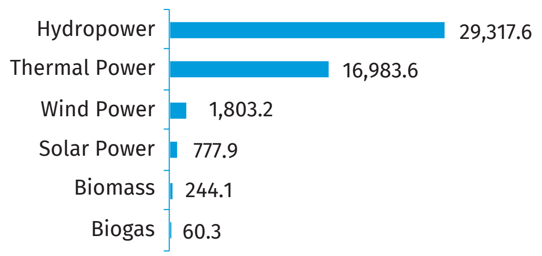
Figure 1. **Installed Electricity Capacity by Source in Peru in 2020 (MW)**



Source: OSINERGMIN[5]

Total net electricity generation in 2020 amounted to 49,186.7 GWh, representing a 7 per cent decline from 52,899.1 GWh produced in 2019. In 2020, hydropower produced 29,317.6 GWh (approximately 60 per cent of the total), thermal power 16,983.6 GWh (nearly 35 per cent) and other renewable energy sources (RES), including wind power, solar power, biogas and biomass, contributed a combined 2,885.5 GWh (6 per cent) (Figure 2).[6]

Figure 2. **Annual Electricity Generation by Source in Peru in 2020 (GWh)**



Source: COES[6]

The difference between installed and available capacity, as well as the low electricity generation by thermal power relative to installed capacity, is explained by the fact that significant reserve capacities of thermal power exist in Peru that are generally not utilized, as the country continues to work towards reducing its reliance on fossil fuels and prioritizing power generation from RES, including hydropower. Notably, despite an overall decrease in generation between 2019 and 2020, caused in large part by the impact of the COVID-19 pandemic, generation from RES including small hydropower (SHP) actually grew from 4,504.9 GWh in 2019 to 4,970.5 GWh in 2020, indicating a 10 per cent increase. The share of RES in annual electricity generation thus increased from 8.5 per cent in 2019 to 10.1 per cent in 2020.[6]

Access to electricity in Peru is near-universal, having improved dramatically in recent years and reaching 98 per cent in 2019.[7] The number of connected users has increased from approximately 4,879,000 in 2009 to 7,614,000 in 2019 with peak demand rising accordingly, from 4,322 MW to 7,018 MW over the same period.[5] Peak demand increased again in 2020, amounting to 7,125 MW.[6] However, the electricity grid of Peru, the National Interconnected Electric System (SEIN), has not fully kept pace with the growth of generation capacity and demand.

The key public institution overseeing activities in the energy sector of Peru is the Ministry of Energy and Mines (MINEM), which develops the legal and institutional framework for activities in the sector. Additional agencies involved in the energy sector include:

- The Supervisory Agency for Energy and Mining Investment (OSINERGMIN), which among other functions sets and regulates electricity tariffs;
- The Electrical Infrastructure Administration Enterprise (ADINELSA), a coordination agency working with local and regional authorities to provide rural electrification services; and
- The Committee for the Economic Operation of the Electric System (COES), a technical entity comprising the owners of generation plants and transmission systems, which coordinates the operation and development of the national grid (SEIN) and manages the short-term market.[8]

The electricity sector in Peru has undergone several major reforms in the last 30 years, starting with the Electricity Concessions Law of 1992, which set up a new tariff structure for end users and unbundled generation, transmission and distribution activities in the sector, allowing private entities to play a larger role. In 2006, the Law for Efficient Generation Development was adopted, aiming to guarantee efficient generation of electricity as well as to reduce the vulnerability of the electricity system to price volatility and blackouts. The law promoted longer tenders and contract terms in order to support investment in large-scale generation, implemented further tariff changes and established two new types of transmission systems—one for supplementary transmission and one for guaranteed transmission.[9] The key document outlining the ongoing and planned development of the electricity sector of Peru is the National Rural Electrification Plan 2016–2025. Among other targets, the plan aims to provide electricity access to 3.3 million people by 2025.[10] Efforts are being made to increase access to electricity via auctions for solar photovoltaic systems, grid extension, mini-grids with hydropower, solar and wind power.[8]

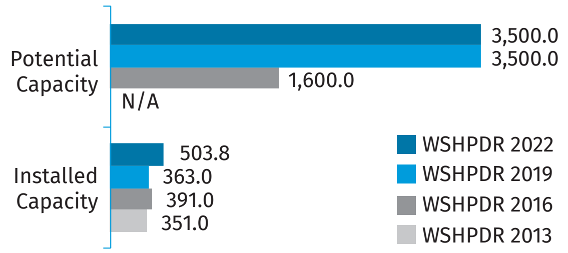
The Office for Tariff Regulation (GART), part of OSINERGMIN, regulates transmission and distribution tariffs.[8] The average tariffs have increased from 0.083 USD/kWh in 2009 to 0.103 USD/kWh in 2019.[5] Tariffs vary across economic sectors and regions.[6]

SMALL HYDROPOWER SECTOR OVERVIEW

In Peru, SHP plants are defined as hydropower plants with an installed capacity of up to 20 MW. As of 2020, there were 46 SHP plants operating in the country with a total installed capacity of 503.8 MW.[11]

In 2016, MINEM carried out an evaluation of the country's hydropower potential, identifying 380 potential SHP sites with a combined installed capacity of 3,311 MW.[12] While it is not known which of the sites identified in the study have been developed since 2016, total potential capacity for SHP in Peru, including existing plants, is estimated at 3,500 MW. This suggests that as of 2021, approximately 14 per cent of the potential capacity has been developed. Relative to the *WSHPDR 2019*, installed capacity has increased by almost 39 per cent due to the commissioning of many new SHP plants in recent years, while potential capacity has remained the same due to lack of more recent rigorous assessments (Figure 3).[9]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Peru (MW)**

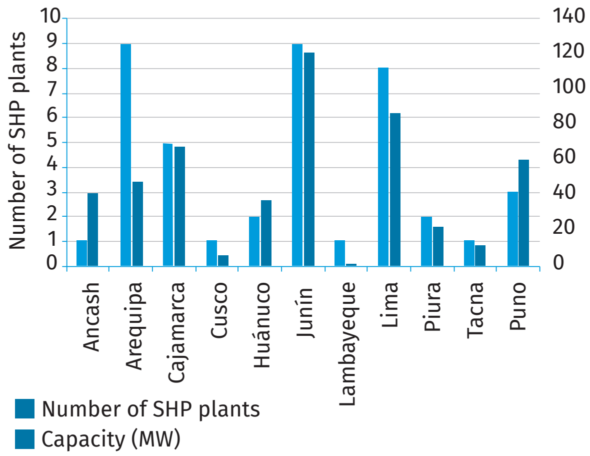


Source: OSINERGMIN,[11] *WSHPDR 2019*,[9] MINEM,[12] *WSHPDR 2013*,[13] *WSHPDR 2016*[14]

In terms of the regional distribution of SHP plants in Peru, the largest number of plants can be found in the regions of Arequipa (9 plants), Junín (9 plants) and Lima (8 plants), while the largest installed capacity of SHP is found in Junín (121.2 MW) and Lima (87 MW), which account for approximately 47 per cent of the installed capacity of SHP nationwide (Figure 4).[11] This distribution of installed capacity coincides with electricity demand, as Junín and Lima are two of the country's most heavily populated regions. A list of 20 most recently commissioned SHP plants is displayed in Table 1.

Figure 4. **Distribution of Small Hydropower Plants and**

Installed Capacity by Region in Peru



Source: OSINERGMIN[11]

Table 1. **List of Selected Existing Small Hydropower Plants in Peru**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Operator*	*Launch year*
Purmacana	Lima - Barranca	1.8	100.0	Electrica Santa Rosa	2019
HER 1	Lima - Lima	0.7	4.5	ENEL Generación Perú	2018
Carhuac	Lima - Huarochiri	20.0	120.3	Andean Power S.A.	2018
Zaña 1	Cajamarca - San Miguel	13.2	242.0	Electro Zaña S.A.C	2018
Yarucaya	Lima - Huaura	17.5	168.9	Huaura Power Group S.A.	2017
Renovandes H1	Junín - Chanchamayo	20.0	293.7	Empresa de Generación Eléctrica Santa Ana S.R.L.	2017
Marañon	Huánuco - Huamalles	18.4	83.5	Hidroeléctrica Marañon S.R.L.	2017
Chancay	Lima - Huaral	19.2	668.2	SINERSA	2016
Rucuy	Lima - Huaral	20.0	666.0	Empresa de Generación Eléctrica Río Baños	2016
Carpapata III	Junín - Tarma	12.8	124.5	Generación Hidroeléctrica Atocongo S.A.	2016
Pátapo	Lambayeque - Chiclayo	1.0	16.5	Hydro Patapo S.A.C.	2016
Runatulo III	Junín - Concepción	20.0	419.9	Empresa de Generación Eléctrica de Junín	2014
Runatulo II	Junín - Concepción	19.1	318.5	Empresa de Generación Eléctrica de Junín	2014
Canchayllo	Junín - Jauja	5.3	85.2	Empresa de Generación Canchayllo S.A.C.	2014
Potrero	Cajamarca - San Marcos	19.9	125.4	Empresa Eléctrica Agua Azul S.A.	2014
Ángel I	Puno - Carabaya	19.9	270.0	Generadora de Energía del Perú S.A.	2014
Ángel II	Puno - Carabaya	19.9	285.0	Generadora de Energía del Perú S.A.	2014
Ángel III	Puno - Carabaya	19.9	287.0	Generadora de Energía del Perú S.A.	2014
8 de agosto	Huánuco - Huamalles	19.0	130.0	Generación Andina S.A.C.	2014
Manta	Ancash - Corongo	19.8	392.5	Peruana de inversiones en energías renovables	2013

Source: OSINERGMIN[11]

As of 2021, there were 24 ongoing SHP projects in Peru, with a total planned installed capacity of 288.5 MW. The projects all have concession contracts, with construction to be completed by 2024, but several have been delayed indefinitely and are currently undergoing further negotiations.[15,16] Several ongoing SHP projects are listed in Table 2.

Table 2. **List of Selected Ongoing Small Hydropower Projects in Peru**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Developer*	*Planned launch year*	*Development stage*
Shima	San Martin - Huallaga	9.00	192.6	Energia Hidro S.A.C.	2021	Pending construction
Campanayocc	Ayacucho - Huamanga	4.62	530.0	MPJ Consulting S.A.C.	2022	In tender
Marca	Junín - Yauli	8.98	12.8	Acqua Energia	2023	Final design phase
Alcaparrosa	Junín - Yauli	9.53	11.7	Acqua Energia	2023	Final design phase
Moquegua I	Moquegua - Mariscal Nieto	15.3	538.8	EGESUR	2024	Under construction

Source: OSINERGMIN[15,16]

RENEWABLE ENERGY POLICY

Support for the development of RES in Peru was established by Legislative Decree No. 1002 for the Promotion of Investment for Electricity Generation with the use of Renewable Energy of 2008. The decree identified the development of generation of electricity from RES as a public necessity and mandated the formulation of a National Renewable Energy Development Plan, which would set a five-year rolling target share of total generation to be met by RES, excluding large and small hydropower. The subsequent plan set a 5 per cent target for generation from RES by 2013 (generation share from non-hydropower RES amounted to approximately 6 per cent in 2020).[6,8,17]

Also in 2008, the Government issued the Regulation for Electricity Generation with Renewable Energy, which determined the administrative procedures for renewable energy auctions and the granting of concessions for RES development, outlined the requirements for submitting, evaluating and awarding bids and set marketing procedures and RES tariffs.[8]

Financial and regulatory support measures for RES development include the following:

- An annual maximum accelerated depreciation of 20 per cent on income tax for all RES projects, which applies to machinery, equipment, installation, operation and maintenance work for grid-connected plants;
- Power producers using RES are entitled to early recovery of the value-added tax (VAT) from electricity sales;
- For SHP projects under 10 MW of installed capacity, permits are applied for at the regional level near the project site and no Environmental Impact Assessment (EIA) is required; instead, the developer must file a non-environmental impact commitment document.[8,9,18]

COST OF SMALL HYDROPOWER DEVELOPMENT

Previous studies concluded that a project cost of approximately 850–1,000 USD/kW is the upper limit for the market viability of SHP development in Peru, based in part on the low cost of electricity generation from the country's abundant natural gas reserves. With the generation price increased to 0.056 USD/kWh, a project cost of 1,400 USD/kW would be potentially viable.[9,19] However, most recently constructed SHP plants have exceeded these upper limits by a wide margin, with project costs ranging from 1,200 USD/kW to 4,200 USD/kW.[11]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The primary mechanism for financing RES and other energy projects in Peru is project finance, whereby the project's revenues from operation are expected to be sufficient for repayment. The auction system for electricity generation projects provides an annual income guarantee, established by the tariff awarded on a project-by-project basis during the public auction and multiplied by the expected annual energy deliveries to the grid, with priority of dispatch and access to transmission and distribution networks likewise guaranteed. Power Purchase Agreements (PPAs) are signed for a period of 20 years.[8]

The Government of Peru has promoted the Clean Development Mechanism (CDM) first established under the Kyoto Protocol to attract international investment into the country's RES sector. In 2020, Peru and Switzerland signed a bilateral carbon offset agreement that will finance green energy development in Peru through additional levies issued by motor fuel importers in Switzerland, counting towards the latter country's virtual emissions reduction.[19,20]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The impact of El Niño results in a great variability in the rainfall intensities in Peru, especially along the northern coast during the summer months. In 1998, extreme weather events caused by El Niño resulted in damage to the energy sector estimated at USD 166 million, of which 67 per cent corresponded to damage to hydropower infrastructure.[21] Similarly, during the coastal El Niño event of 2017, multiple hydropower plants in Peru incurred damage to their infrastructure, including the Callahuanca hydropower plant, which required two years of work and USD 45 million of investment for subsequent reconstruction.[22] With the intensity of El Niño increasing due to the ongoing global climate change, the hydropower sector in Peru can be expected to incur additional costs from related extreme weather events in the future.[23]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Peru is a country rich in RES, but only a small fraction of this potential is currently used. While investment in the renewable energy sector has been growing, the development of RES, including SHP, continues to face several obstacles, including the following:

- High initial investment costs compared to thermal power plants;
- Lack of sufficient human capacity for operation and maintenance and high cost of training;
- Limited transport and construction infrastructure impeding projects;
- Environmental concerns;
- Limited awareness in the financial sector of the RES market and profitability of RES projects, as well as project evaluation criteria and regulations. This leads to a situation where banks require external technical support to assess RES projects.

Enablers for SHP development include:

- The country's considerable untapped SHP potential;
- The experience and commitment of the country to hydropower development in general;
- Support offered in the form of long-term PPAs at guaranteed prices available for RES projects, as well as certain tax rebates.

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Suriname

Laura Stamm, International Center on Small Hydro Power (ICSHP)

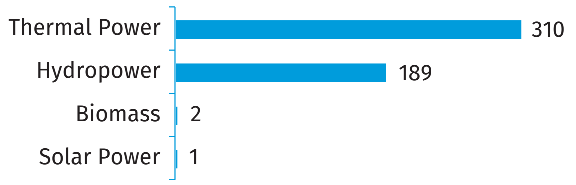
KEY FACTS

Population	586,634 (2020)[1]
Area	163,820 km^2 [2]
Topography	Suriname is located on the north-eastern coast of South America and the large majority of its territory is covered with tropical rainforest. The country can be divided into four ecological zones. The New Coastal Plain in the north is a flat swampland on the Atlantic coastline. Just south of this is the Old Coastal Plain, which is mostly flat but with some ridges and hills. The Wilhelmina Mountains are located in the central to southern region and has the highest altitudes. Juliana Top is the highest peak in the country at 1,230 metres. The Sipaliwini Plain is a savanna region that stretches down to the southern border with Brazil.[3]
Climate	Suriname has a tropical climate with dry and rainy seasons. Temperatures mostly remain between 21 °C and 32 °C. However, the coastal north usually only experiences the upper half of the range and the central and southern highlands experience the whole range. The driest period is between August and December, whereas the wettest season is between April and August. January to February is considered a short and minor wet season, while March to early April is a short and minor dry period.[3,4]
Climate Change	Over the past three decades, average rainfall in Suriname has shown an increase in all areas of the country and over a 500 mm per decade increase in the south-western region. However, it is predicted that by the end of the century overall rainfall will decrease, especially in the north. Temperatures have shown to increase in the northern region over the past three decades, but decrease in the south. Over the course of the next decades, average temperatures are expected to increase throughout the whole country by between 2 °C and 5 °C. Extreme weather events are also expected to increase.[4]
Rain Pattern	Rainfall varies between regions and periods of the year, but average rainfall is between 1,900 mm and 2,400 mm per year. Throughout the country, rainfall is highest between late April and early August when severely heavy rains are a common occurrence. Average rainfall in May, the wettest month, is approximately 325 mm.[3,4]
Hydrology	There are seven major rivers in Suriname, which drain northwards towards the Atlantic Ocean. These are the Maroni, Corentyne, Commewijne, Suriname, Saramacca, Coppename and Nickerie. There are no rivers that cross into or out of Suriname. The rivers mentioned are on the border of the country but not considered to be border rivers. Nani Lake is the only natural fresh water lake, with total dam capacity estimated at 20 km^3. Brokopondo Lake is the largest lake in the country covering 1,560 km^2. Swamps, which are characterized by stagnant water, dense tropical forest and large amounts of decaying vegetation, cover approximately 60 per cent of the Coastal Plains.[5]

ELECTRICITY SECTOR OVERVIEW

In 2020, the total installed capacity of Suriname was approximately 502 MW. The country's energy mix consisted of 310 MW (just under 62 per cent) from fossil fuels, 189 MW (38 per cent) from hydropower, 2 MW from biomass and 1 MW from solar power (Figure 1).[6] The 189 MW of hydropower capacity comes from the Afobaka plant, which was originally built by and ran by Suralco, a foreign private mining company, but was given to the Government of Suriname upon the company leaving the country in 2019.[7]

Figure 1. **Installed Electricity Capacity by Source in Suriname in 2020 (MW)**



Source: OLADE[6]

In 2020, total electricity generation was 2,368 GWh. Thermal power generated 1,252 GWh (53 per cent), hydropower generated 1,105 GWh (46 per cent) and the remaining 1 per cent comprised 9 GWh from solar power and 2 GWh from biomass (Figure 2).[6] Due to inefficient infrastructure, loss of electricity is considered an issue of concern for Suriname and in 2019 losses amounted to 452 GWh, or 19 per cent of total electricity generated.[8]

Figure 2. **Annual Electricity Generation by Source in Suriname in 2020 (GWh)**

Source: OLADE[6]

The electrification rate in Suriname in 2019 was just under 98 per cent. More than 99 per cent of the urban population has access to electricity, whereas slightly less than 96 per cent of the rural population does.[9] In many rural areas, the most common source of energy is diesel generators, which typically only provide the communities with electricity for four to six hours per day.[10]

The two major national companies that are responsible for the generation, distribution and transmission of electricity are the State Oil Company of Suriname (Staatsolie) and the Suriname Energy Company (EBS). Originally, Staatsolie was an oil producing company and generated exclusively thermal energy, but since 2007 has sought to diversify into renewable energy with the creation of its renewable energy unit. After first diversifying into biomass in 2010, it now also generates hydropower since the transfer of control of the Afobaka hydropower plant.[11] EBS is responsible for the distribution and transmission of electricity. EBS's current major focus in improving the quality of electricity transmission and distribution infrastructures is to decrease losses and increase energy stability in the country.[10]

Table 1. **Average Electricity Tariffs by Consumer Type in Suriname**

Type of consumer	*Usage*	*Tariff (USD/kWh)*
Residential	Up to 800 kWh	0.056
	Above 800 kWh	0.087
Non-residential	Up to 2,600 kWh	0.056
	Above 2,600 kWh	0.087
Street lighting	N/A	0.079

Source: EAS[12]

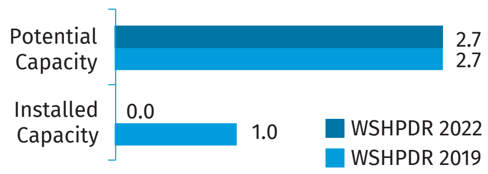
Before the implementation of the 2016 Electricity Act, the average retail electricity tariff in Suriname was 0.04 USD/kWh. This was one of the lowest tariffs in Latin America and the Caribbean and was supported by Government subsidies. In order to better regulate appropriate electricity tariffs, the Energy Authority of Suriname (EAS) was created and began operating in 2020. The details of the average tariff for each type of consumer per Decree No. 88 of 2021 are given in Table 1.[12]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official country definition for small hydropower (SHP) in Suriname. In this chapter, SHP is defined as the plants with a capacity of less than 10 MW. It is estimated that the total potential capacity of hydropower in the country is 2,419 MW.[13] Based on previously planned projects, SHP potential is at least at 2.7 MW.[14] Plans for achieving at least 2.7 MW of SHP installed capacity were included in the initial plan of the Development of Renewable Energy, Energy Efficiency and Electrification of Suriname Project. However, due to budget limitations, the Ministry of Natural Resources submitted a restructuring proposal on 7 April 2017 and it was agreed that the Rural Small Hydro Project section would be cancelled.[15]

There have been some SHP plants that were in operation within the country in the past, but all have since closed. Poeketi was the first SHP plant constructed in Suriname. It was completed in 1981 and supplied 50 kW to the nearby community until it shut down in 1987.[16] In 2005, construction began on the Gran Olo Sula plant with the goal capacity of 300 kW, but due to flooding and financial issues, it was not completed until 2017, with a lower capacity than planned and was in operation for five days before it was shut down.[17] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, SHP installed capacity decreased based on more accurate data, whereas the potential remained unchanged (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2019/2022 in Suriname (MW)**



Sources: GEF & IADB,[14] *WSHPDR 2019*[18]

RENEWABLE ENERGY POLICY

The National Energy Plan of 2013–2033 was one of the earliest official declarations of the country's interest in expanding renewable energy. Initiatives stated in the plan include goals to bring solar power and SHP to remote areas in the southern region as well as general interest to consider wind power as a possibility to explore.[19] The Policy Development Plan 2017–2021 further stresses the importance of renewable energy and discusses the need for innovative business models to feasibly bring it into the remote interior of the country. It suggests that public-private partnerships could be a key to achieve this.[20]

In 2016, the first comprehensive energy-related legislation was enacted. The Electricity Act of 2016 set out to improve the technical and financial situation of the power sector. The aim of this act was to create an energy regulatory authority, deal with the issue of overly low electricity tariffs by recommending a reduction in subsidies, allow for privatizations and to state the importance of attracting more investment into renewable energy.[21] The act created the EAS to oversee the tariffs of the country's energy sector. The specifics of how tariffs will be calculated by the EAS were published in the subsequent Electricity Sector Plan 2019–2023.[22] The act also mandates EBS to hold renewable energy tenders under the supervision of the EAS and obligates the company to purchase all solar and wind power generated by respective plants. Furthermore, it gives consumers the possibility of generating their own electricity using a net metering system that requires that the surplus electricity generated is fed back into the national grid. This amount cannot exceed total consumption for the year.[10,21]

The Environmental Framework Act of 2020 addresses appropriate environmental management. It includes the legal framework and procedures for environmental impact assessments and created the National Environmental Authority (NMA) to oversee this. The aim of this act was to more closely align the legal framework of the country with global environmental standards and to demonstrate commitment to international agreements such as the Paris Agreement.[22]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The following barriers are particularly critical for SHP development in Suriname:

- Lack of funding, exemplified by the numerous cases of plans to develop projects being cancelled or plants being shut down soon after construction;
- Lack of local technical knowledge and skills in SHP development;
- High setup costs, in part due to the absence of road infrastructure leading to remote villages.

The following enablers may incentivize SHP development in Suriname:

- Electricity demand is continuously increasing and the installed capacity will soon have to increase to keep up;
- Over 100 villages do not have electricity for the entire day and depend on diesel generators and the monthly delivery of a finite amount of diesel to power them. SHP could greatly improve the quality of their electricity access and energy stability;
- SHP would also lessen the country's dependence on the one large hydropower plant, Afobaka.[20]

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Uruguay

Cecilia Correa Poseiro and Arturo Alarcón, Inter-American Development Bank

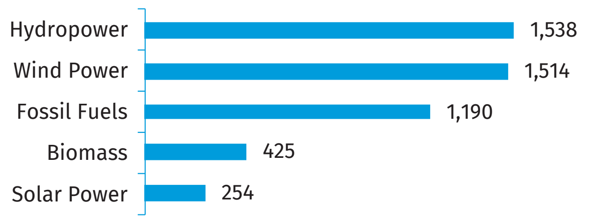
KEY FACTS

Population	3,473,727 (2020)[1]
Area	176,215 km^2[2]
Topography	Uruguay has a low and slightly sloping topography with an average elevation of 116.7 metres above sea level. The relief is homogeneous, with two large structural areas: peneplains and plains. The peneplains are gently undulating reliefs that extend over most of the country's territory and contain rounded hills with a wide base, which are known as cuchillas and reach a maximum height of 514 metres. The plains extend in the peripheral areas of the Uruguay River, the River Plate and the Atlantic Ocean.[2,3]
Climate	Throughout its entire territory Uruguay has a homogeneous climate characterized as a temperate-humid one without a dry season. The average annual temperature is 17.5 °C, with a maximum average of 19 °C in the north and 16 °C on the Atlantic coast. The average temperature in winter is 11.5 °C and in summer 23.9 °C. The minimum temperatures occur in winter, generally in July; and the maximum temperatures occur in summer, generally in January.[3,4,5]
Climate Change	The average annual temperature is showing an increasing trend. The year 2017 was one of the warmest years on record with an average temperature of 18.7 °C, a maximum average of 24.1 °C and a minimum average of 13.2 °C.[6] Studies have also detected an increase in average precipitation between 1961 and 2017 with an average increase of 10 per cent in the north of the country and 15–20 per cent in the south.[7]
Rain Pattern	Average annual rainfall is approximately 1,300–1,400 mm. Precipitation demonstrates considerable annual variability with a minimum average of 900 mm recorded in 1989 and a maximum average of 2,100 mm recorded in 2002, according to the statistical period of 1980–2009.[6] On average, precipitation is equally distributed across the four seasons of the year (300–350 mm in each season).[7] The phenomena that affect the rainfall patterns in Uruguay the most are the Niño-Southern Oscillation, which increases precipitation probability, and La Niña, which generates prolonged and deep droughts. Both phenomena could become more frequent with an increase in the average global temperature.[8]
Hydrology	The main water basins in the country are the Uruguay River in the west, the River Plate in the south-west, the Black River in the centre of the country, the Santa Lucia River in the south, the Atlantic Ocean in the south-east and the Merin Lagoon in the centre-east. The Uruguay River (100,000 km^2 basin in Uruguay), the River Plate, the Black River and the Santa Lucia River belong to the main basin of the River Plate.[9] The River Plate Basin has a total area of 3,100,000 km^2, making it the fifth largest in the world, and covers five countries: Argentina, Bolivia, Brazil, Paraguay and Uruguay.[10] The Merin Lagoon and the basin of the Atlantic Ocean pour directly into the Atlantic Ocean.[11]

ELECTRICITY SECTOR OVERVIEW

In 2019, the installed electricity capacity of Uruguay stood at 4,920 MW. Of the total, 31 per cent came from hydropower, 31 per cent from wind power, 9 per cent from biomass, 5 per cent from solar photovoltaics (PV) and the remaining 24 per cent from fossil fuel thermal plants (Figure 1).[12] The installed capacity increased by 80 per cent in the last 10 years (compared to 2,690 MW in 2010), mainly due to the installation of 1,473 MW of wind power capacity, 253 MW of solar power and 540 MW of thermal power (combined cycle).[12]

Figure 1. **Installed Electricity Capacity by Source in Uruguay in 2019 (MW)**

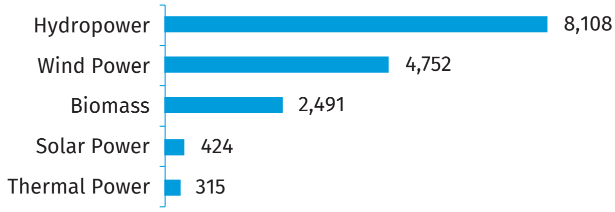


Source: MIEM[12]

Most of the hydropower potential in Uruguay (estimated at 1.8 GW), has been utilized, making it the country with the highest hydropower potential utilization rate in the region (85 per cent).[13] Of the 1,538 MW of the total installed hydropower capacity, 108 MW correspond to the Baygorria hydropower plant, 152 MW to Gabriel Terra, 333 MW to Constitucion and 945 MW to Salto Grande (50 per cent of the plant's capacity of 1,890 MW belong to Uruguay).[14]

Electricity generation in 2019 amounted to 16,088 GWh, of which 50 per cent was from hydropower, 30 per cent from wind power, 15 per cent from biomass, 3 per cent solar power and 2 per cent fossil fuel thermal power (Figure 2).[12] The maximum demand was 11,023 GWh and the maximum power was 2,121 MW. Electricity consumption per capita in 2019 stood at 3.22 MWh and has showed an average annual growth of 2 per cent over the last decade. The electrification rate in the country is 99.8 per cent, with 99.9 per cent in urban areas and 98.9 per cent in rural areas.[12]

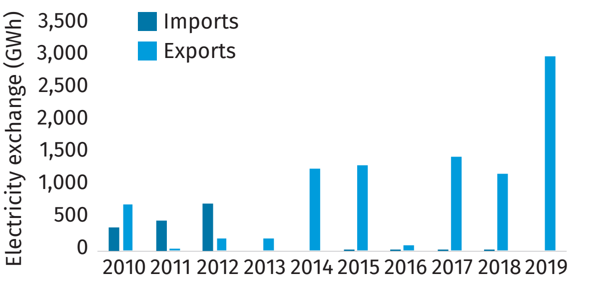
Figure 2. **Annual Electricity Generation by Source in Uruguay in 2019 (GWh)**



Source: MIEM[12]

The electricity system of Uruguay is interconnected with that of Argentina via the 132/150 kV Concepción-Paysandú interconnection of 100 MW and the 500 kV Salto Grande transmission quadrilateral, which is composed of the 1,890 MW Salto Grande interconnection line and the 1,386 MW Colonia Elía-San Javier interconnection line. Uruguay is also connected to the electricity system of Brazil via two 50Hz/60Hz frequency converters: Santa Ana de Livramento with a capacity of 70 MW and the Melo converter with a capacity of 500 MW. From 2013 to 2019, Uruguay was a net exporter of electricity (Figure 3).[15] In 2019, the country exported 3,012 GWh of electricity (80 per cent to Argentina and 20 per cent to Brazil).[16]

Figure 3. **Electricity Exports and Imports of Uruguay in 2010–2019 (GWh)**



Source: MIEM[15]

The electricity transmission system of Uruguay is composed of 5,790 kilometres of high-voltage lines (500 kV, 230 kV, 150 kV and 60 kV). The electricity distribution system consists of 4,960 kilometres of 60 kV and 30 kV lines; 53,097 kilometres of 22 kV, 15 kV and 6 kV lines; and 28,178 kilometres of 230 V and 400 V lines. There are 3,902 medium-voltage substations and 4,684 medium-voltage/low-voltage substations.[16]

The electricity mix of Uruguay has undergone a significant transformation over the last 10 years. Until 2007, it was mainly composed of hydropower and thermal power generation from fossil fuels. This created high dependence on rain patterns, electricity exchanges with the neighbouring countries and fuel imports. In 2007, Uruguay incorporated a significant proportion of biomass into its electricity mix, while the first wind farm in the country began to operate in 2009. Already in 2017 the country's mix of electricity sources was highly diversified, with more than 1,500 MW of wind power capacity, 420 MW of biomass and 240 MW of solar power. The clear regulatory framework, tax incentives for the private sector and financial innovation that increased the bankability of the projects were key for this transformation.[17]

Currently, there are 43 wind farms that generate and sell electricity to the public electric utility the National Administration of Power Plants and Electrical Transmissions (UTE) through power purchase agreements (PPA). Of these, 38 are fully privately owned under a public-private partnership (PPP).[17] The financial models of these projects vary: three wind farms were fully publicly financed, four received partial public financing (from 6 per cent to 50 per cent), 40 were fully privately financed and three are owned by UTE. For the last group of projects UTE emitted fixed-rate bonds and shares to finance between 10 per cent and 24 per cent of each project.[17]

The electricity sector of Uruguay is governed by Law 18.632/97 New Regulatory Framework for the Electricity Sector. The sector is regulated by the Energy and Water Services Regulation Unit (URSEA), which was assigned greater control competence by the 2020 Emergency Consideration Law (Law 19889), and the National Energy Directorate under the Ministry of Industry, Energy and Mining (MIEM). The entity in charge of planning and operating the electricity system is the Electricity Market Administration (ADME).

The public electricity utility UTE is a decentralized and vertically integrated state agency founded in 1912 and governed by an Organic Law (Law 15,031/80). The responsibility of UTE is to guarantee the sustainably of electricity service provision to its 1,512 million customers (2019).[16] UTE owns generation assets and has a monopoly on electricity transmission and distribution in the country. In the generation subsector, UTE participates with approximately 38 per cent of the system's installed capacity and an additional 7 per cent as a co-owner. Furthermore, the Salto Grande binational hydropower project accounts for 19 per cent of the total installed capacity, while the rest is owned by the private sector.[16] Private parties are free to participate in the generation sector and can either sell their electricity on the spot market or sign PPAs with the electric company. The generation units of UTE are dispatched according to their marginal cost.

Electricity tariffs are proposed by UTE and approved by the Government with the authorization (not binding) of URSEA and the Office of Planning and Budget (Law 16.832). URSEA is responsible for calculating the technical reference fee. There are several types of residential tariffs: simple residential, basic residential, general simple, double hour, triple hour and general seasonal hour (Table 1).[18] The double hour, triple hour and general seasonal hour tariff categories were established to encourage greater demand management and system efficiency. There are also several energy efficiency programmes that have an impact on the affordability of the electricity services. In addition, there are various tariffs for medium- and large-scale consumers.

Table 1. **Residential Electricity Prices by Category in Uruguay in 2021**

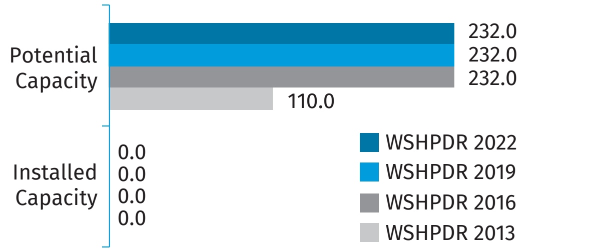
Tariff category	*Price (USD)*		*Description*
	Fixed charge	*Variable per kWh*	
Residential simple	5.42 + 1.68 per kW of power contracted	0.14	Consumption of 1–100 kWh per month
		0.18	Consumption of 101–600 kWh per month
		0.22	Consumption > 601 kWh per month
Residential double schedule	9.78 + 1.68 per kW of power contracted	0.23	Peak hours: 4 consecutive hours between 17:00 and 23:00
		0.09	Off-peak hours (Saturday, Sundays, holidays)
Residential triple schedule	9.78 + 1.68 per kW of power contracted	0.23	Peak hours: 4 consecutive hours between 17:00 and 23:00
		0.12	Shoulder hours: rest of the hours
		0.05	Valley hours: 0:00 to 7:00
Residential basic	8.79	0.18	Consumption of 101–140 kWh per month
		0.33	Consumption of 141–350 kWh per month
		0.22	Consumption > 351 kWh per month

Source: UTE[18]

SMALL HYDROPOWER SECTOR OVERVIEW

In Uruguay, small hydropower (SHP) plants are defined as hydropower plants with an installed capacity between 1 MW and 50 MW. Pico-hydropower is defined as less than 5 kW, micro-hydropower as between 5 kW and 100 kW and mini-hydropower as between 100 kW and 1 MW.[19] Currently, in Uruguay there are no hydropower plants in operation of less than 50 MW of capacity. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, both the installed and potential capacity have remained unchanged (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Uruguay (MW)**



Source: Schenzer et al.,[19] *WSHPDR 2013*,[20] *WSHPDR 2016*,[21] *WSHPDR 2019*[22]
Note: Data for SHP up to 50 MW.

Within the framework of the Energy Policy 2005–2030, in 2006 UTE opened a tendering process for PPAs for up to 60 MW of renewable energy capacity from wind power, biomass and SHP (Decree 77/006). The objective was to award 20 MW per technology on an equitable basis. However, although UTE received bids that exceeded the target for the first two technologies, no bids were received for SHP. Following this situation, no new initiatives have been undertaken by the Government for new SHP projects.[23]

In terms of potential SHP projects for generation only, a study developed by the University of the Republic of Uruguay (UDELAR) identified 70 potential sites for a total capacity of 231.5 MW and an annual generation of 1,431 GWh. At each of the identified sites, at least 1 MW of capacity could be installed without affecting protected areas, population centres or major communication routes. Of the identified sites, two are over 10 MW (12.8 MW and 10.7 MW) and the rest are of less than 10 MW. The study selected five of the 70 potential sites to evaluate potential capacity, generation, environmental impact and economic and financial feasibility. Of these, four demonstrated to be economically feasible (Table 2).[19]

Table 2. **List of Selected Potential Small Hydropower Sites in Uruguay**

Name	*Potential capacity (MW)*	*Capacity factor (%)*	*Estimated annual generation (GWh)*
Arapey 80 m	7.00	62	38.69
Arapey 130 m	3.70	62	19.69
Yerbal 88 m	2.60	74	16.59
Arerungua 90 m	8.90	68	52.35

Source: Schenzer et al.,[19] *WSHPDR 2016*[21]
Note: Based on data from 2013.

UDELAR also carried out a study of 913 dams existing in the country to assess the possibility of developing new SHP plants on them and making them multipurpose.[24] As a result, 20 existing dams with the highest generation potential were selected for a pre-feasibility analysis. Considering a continuous irrigation scenario, the annual generation of the projects would vary between 60 MWh and 1,700 MWh with a mean of 380 MWh. Only 14 projects have a positive Internal Rate of Return (IRR), with an average IRR of 4.65 per cent and a maximum of 8.8 per cent. The continuous irrigation scenario is estimated to be the most beneficial one in terms of the IRR.[24]

Additionally, UDELAR undertook a pre-feasibility analysis of 17 most promising new multipurpose dams with irrigation as the priority activity and hydropower generation as secondary.[24] The power range of these dams was estimated at 11–569 kW with a mean of 130 kW for continuous irrigation and at 34–1,706 kW with a mean of 385 kW if used with intermittent irrigation. According to the study, there are 14 cases with a positive IRR, ranging from 0.3 per cent to 8.8 per cent, with a mean of 3.3 per cent, when considering continuous irrigation. There are six cases with a positive IRR ranging from 0.7 per cent to 6.7 per cent with a mean of 1 per cent when considering intermittent irrigation.[24] These studies provide a solid foundation for the development of SHP projects in Uruguay, both on new and existing dams. Nonetheless, as mentioned in the document, the sector has been more interested in developing other renewable energy sources in recent years.

RENEWABLE ENERGY POLICY

In 2008, the Government of Uruguay approved the Energy Policy 2005–2030 based on four axes: institutional, supply, demand and social. For each of the axes, the policy set general and specific objectives. With regard to supply, it established specific goals for 2015, including the contribution of domestic renewable energy sources to the country's primary energy mix as well as a 15 per cent share of non-conventional renewable sources (wind power, biomass waste, micro-hydropower) in the country's electricity generation.[25] This goal has been achieved, with electricity generation from non-conventional renewable sources having surpassed 20 per cent already in 2014.[12] The Energy Policy was endorsed by all political parties with parliamentary representation, which provided clarity and certainty to private actors. Furthermore, as of the moment of writing of this chapter the Government was working on the design of the Energy Policy 2020–2050, which was expected to be issued in 2021.

Internationally, Uruguay ratified the Paris Agreement and submitted its Nationally Determined Contributions (NDCs) in 2017, setting specific mitigation measures for the energy sector.[26] These include targets for the wind power, solar power and biomass total installed capacity, which have already been exceeded by 104 per cent, 110 per cent and 110 per cent, respectively.[27] Uruguay has also announced its commitment to prepare and present a long-term strategy for low greenhouse gas emissions development, to increase adaptation to the climate crisis and promote weather resilience.[28] One of the commitments includes an aspirational goal of reaching net zero CO_2 emissions by 2050. The long-term strategy will be aligned with the National Policy of Climate Change of 2017.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Within the framework of the National Water Policy (Law 18,610), Decree 205/017 approved the National Water Plan. It establishes several programmes and projects for integrated water management. These are focused on sustainability and risk control, development of management plans and information and capacity building systems. The plan also establishes the importance of large-scale hydropower but recognizes that there is no potential for additional new large- and medium-scale projects. Additional hydropower capacity may come from the modernization and repowering of existing large-scale plants or smaller-scale projects. Ultimately, the plan recognizes that viable SHP projects are those resulting from new or existing multipurpose reservoirs. For multipurpose dams with potential capacity of less than 10 MW (irrigation and generation), irrigation is to remain the priority water use.[29]

Law 16466 (Environmental Impact Assessment Law) establishes that for the construction or modernization of any power plant of more than 10 MW of any kind, including SHP plants, an environmental impact assessment (EIA) must be carried out. EIAs are also required for the construction of dams with a reservoir capacity greater than 2 million m^3 or whose water mirror exceeds 100 hectares and with water intakes with a flow greater than 500 litres per second.[30]

Furthermore, Decree 173/010 regulates bidirectional electricity exchange with the distribution network for micro-generators. It allows subscribers to generate electricity for self-consumption and to inject the surplus into the distribution network if the maximum current generated in low voltage does not exceed 16 A or 25 A for single-wire ground return.[31]

Finally, a range of investment promotion policies also apply to potential SHP projects. Thus, Law 16906 on Investments and Industrial Promotion declares of national interest the promotion and protection of investments made in the national territory. It provides important incentives and tax benefits to companies that make investments. In particular, Decree 354/009 declares of national interest the investments in projects of domestic and renewable energy generation, including SHP. Such projects will receive the benefits established by Law 16906. According to Decree 354/009 and then Decree 2/012, Decree 143/018 and Decree 268/020, projects score in various defined policy areas and according to the final score companies can exempt a percentage of the value of the investment project in taxes.[32,33,34]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers to the implementation of SHP projects in Uruguay include the following:

- The annual variability of rainfall in the country is greater than the annual variability of wind and sun. The average solar and wind power generation in a quarter will be similar to any other quarter in the same historical series. However, to find two similar hydraulic years in terms of average production, a 20-year moving window should be used.[35] The variability of hydrological conditions therefore implies an additional risk for SHP developers compared to wind or solar energy.
- High transactional costs for projects that require new dams and reservoirs due to the need to obtain several approvals with different agencies (National Energy Directorate, National Water Directorate, Ministry of Environment, General Directorate of General Resources, UTE, etc.) and the lack of experience in the processing of this kind of projects.[36]
- Higher investment costs compared to other non-conventional renewable energy technologies such as wind and solar power, which have seen a significant cost reduction in recent years.[36]
- The small scale of potential projects and the difficulty of standardization affect the interest of suppliers to participate and the chances of obtaining competitive prices.
- There are socio-environmental restrictions for the construction of projects involving the development of new reservoirs or dams.
- High perceived risk of hydropower development, compared with other non-conventional renewable energy projects such as wind and solar power, which affects investment conditions.
- Limited tariff incentives that remunerate all the services that SHP plants can provide, such as peaking power, for instance.
- Limited experience and knowledge of the different stages of SHP projects (planning, implementation, operation, and maintenance).[22]

In spite of the listed barriers, opportunities for SHP development in Uruguay exist, in particular taking into account the following factors:

- Availability of untapped SHP potential and data on sites suitable for development;
- The policy framework favouring the exploitation of domestic renewable energy technologies, including SHP.

Further initiatives that could be considered to support the implementation of SHP projects in the country could include:

- Review of the regulatory framework to allow appropriate retribution to all services that SHP can provide;
- Development of guidelines to facilitate and/or clarify permitting processes;
- Promotion of the development of SHP on already built multipurpose projects where significant investments on civil works are already done;
- Promotion of knowledge of SHP development; and
- Development of financial mechanisms that allow absorbing or dampening differences in earnings due to annual rainfall variability (i.e., revolving funds, insurances).

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Venezuela

Laura Stamm, International Center on Small Hydro Power (ICSHP)

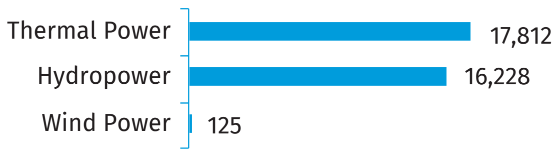
KEY FACTS

Population	28,435,943[1]
Area	912,050 km[2 2]
Topography	The topography of Venezuela is very diverse and includes lowland plains, forested highlands and mountain ranges. The coastal areas to the north are largely plains with a small coastal mountain range near the centre. North-east near the border with Guyana are swampy lowlands centred in the Orinoco Delta. The Andes Mountain Range extends from Colombia into western Venezuela and is the region of the highest altitudes. The highest point is Bolivar Peak, which rises to 4,978 metres. The highlands of the central and southern regions are mostly hills and plateaus covered with jungles and is where Angel Falls, the world's highest uninterrupted waterfall at 979 metres, is located.[3]
Climate	Venezuela has a mild tropical climate, with little variation of temperature in a given region throughout the year. Coastal regions are generally warm and have average temperatures between 22 °C and 28 °C. The lowest temperatures can be found in the Andean Mountain region where it can reach below 8 °C. The wet season for the country is between May and November and the dry season is between December and April.[3]
Climate Change	Climate change has already begun affecting Venezuela and is expected to worsen. Due to rising temperatures, four out of the five glaciers in the country have melted since 1990. By the end of the century, temperatures are expected to increase by between 1 °C and 3.5 °C. Additionally, the recent surge in droughts is expected to become more severe, which will affect water availability throughout the country. Average rainfall is projected to decrease by between 35 mm and 110 mm per annum by 2100.[4,5]
Rain Pattern	Rain patterns vary considerably across regions in Venezuela. The north-western costal region is the driest, with some parts only receiving 280 mm per year. The wettest region is the south-eastern rain forest, where annual precipitation usually exceeds 2,000 mm.[3,6]
Hydrology	The country has rich water resources featuring more than 1,000 rivers. The Orinoco River is the eighth largest in the world and one of the most important rivers in Venezuela. It begins in the southern highlands and does many turns before draining in the Atlantic Ocean through a delta spanning more than 440 kilometres of coastline. Some of the major tributaries are the Caroní, Apure and Meta Rivers. The Orinoco also has a southern branch that flows into the Negro River, a tributary to the Amazon. Lake Maracaibo, in the west, is the largest lake in South America and is fed from the south by 10 rivers and flows into a channel that leads to the Gulf of Venezuela to the north.[3,7]

ELECTRICITY SECTOR OVERVIEW

In 2019, the total installed capacity in Venezuela was 34,165 MW. Of that, 17,812 MW, or approximately 52 per cent, was from thermal power plants, while hydropower accounted for slightly over 47 per cent of the energy mix with 16,228 MW. The installed capacity of wind power plants was 125 MW (Figure 1).[8] However, due to deteriorating infrastructure and institutional hindrances, approximately 75 per cent of the installed capacity is not in operation. In 2019, the total available capacity was approximately 8,565 MW, of which 6,393 MW was from hydropower, 2,162 MW from thermal power and 10 MW from wind power. The single most important power plant in Venezuela is the Simon Bolivar hydropower plant, which has an installed capacity of over 10,000 MW and is the source of electricity for more than 60 per cent of the population. However, the same as most power plants in the country, it has not been able to provide its full installed capacity in recent years.[9]

Figure 1. **Installed Electricity Capacity by Source in Venezuela in 2019 (MW)**



Source: AVIEM[8]

Total electricity production was approximately 109,000 GWh in 2018.[10] More recent data on generation is currently unavailable. In comparison to 2016, electricity generation decreased by roughly 6 per cent. Access to electricity reached 100 per cent in 2019. However, the electricity system in the country lacks reliability, with blackouts occurring on a daily basis. Venezuela is undergoing an electricity crisis, as the situation has not improved in many years, and much of the population is forced to ration their usage.[9]

Under Law 5.330 passed in 2007, the 14 companies that handled the generation, distribution and transmission of electricity were unified into one state-owned company, the National Electricity Company (CORPOELEC). In 2009, the Ministry of Popular Power of Electric Energy (MPPEE) was created to be in charge of regulation, monitoring and evaluation of activities in the electricity sector.[11] Since creation, both CORPOELEC and MPPEE have experienced institutional declines, largely because of widespread corruption and deprofessionalization of the sector. Between the years 2013 and 2018, almost 50 per cent of the employees of CORPOELEC moved out of the country, leaving the company understaffed and the labour market without energy-related skills.[9] The monthly electricity reports of CORPOELEC were discontinued in 2009 and the annual management report of the MPPEE has not been disclosed since 2014.[12] Therefore, obtaining official, up-to-date information on the electricity sector is a challenge.

Electricity tariffs in Venezuela are constantly changing due to supply issues and high inflation, and are therefore difficult to determine. For example, some citizens have reported experiencing up to 3,000 per cent increase in electricity tariffs between 2020 and 2021.[13]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no specific definition for small hydropower (SHP) in Venezuela, therefore, this chapter will refer to SHP as plants of up to 10 MW. There are seven SHP plants in Venezuela, all of them below 1 MW. The total installed capacity is at least 1,393 kW.[14,15] Based on previously identified potential locations for SHP projects, SHP potential in the country is estimated to be at least 49.7 MW. Thus, just below 3 per cent of the potential has been developed so far.[16] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed and potential capacity estimates increased due to access to more accurate data.

The seven SHP plants in operation were all constructed in the second half of the 20th century, the last of which was constructed in 1994 (Table 1). All of the plants are located in the south-eastern region, close to the border with Brazil. They were each constructed with the purpose to serve specific remote or indigenous communities with populations of 1,200 people or less.[14]

Figure 2. **Small Hydropower Capacities in the WSHPDR 2019/2022 in Venezuela (MW)**

Source: López-González,[14] CORPOELEC,[15] GEOA,[16] *WSHPDR 2019*[17]

Table 1. **List of Existing Small Hydropower Plants in Venezuela**

Name	*River*	*Installed capacity (MW)*	*Year*
Canaima	Carrao	0.800	1994
Ciudadela	Aponguao	0.120	1994
Cúao	Cúao	0.030	1990
Arautamerú	Yuruaní	0.150	1988
Wonken	Caruay y Macarupuey	0.058	1983
Kamarata	Tapere	0.125	1962
Kavanayen	Apacairao	0.110	1957
Total		**1.393**	

Source: López-González,[14] CORPOELEC[15]

Though no SHP plants have been constructed in recent years, several potential sites have been identified as possible future projects with a total potential capacity of 48.29 MW (Table 2).

Table 2. **List of Potential Small Hydropower Projects in Venezuela**

Region	*River*	*Potential capacity (MW)*
Perija	El Palmar	3.20
Perija	Apon	3.10
Nor Occidental Andina	La Grita	8.20
Nor Occidental Andina	Motatan	3.52
Nor Occidental Andina	Torondoy	3.40
Sur Occidental Andina	Acequia	8.39
Sur Occidental Andina	Guache	4.30
Sur Occidental Andina	Masparro	2.29
Amazonas	Cataniapo	10.00
Amazonas	Villacoa	1.89
Total		**48.29**

Source: GOEA[16]

There are no known feed-in tariffs or other incentives for SHP. As the country is in a protracted electricity-sector crisis, SHP could be one of the solutions to ensure more efficient access to electricity.

RENEWABLE ENERGY POLICY

The dissemination of diverse renewable energy sources in the country has been considered slow and thus Venezuela is mostly relying on fossil fuel production and large hydropower.

The Homeland Programme and the Economic and Social Development Plan of the Nation 2013–2019 explicitly express national interest in expanding renewable energy in the country. Particular emphasis was put on wind and solar energy in order to diversify the energy mix. The programme aimed to develop an additional 613 MW from renewable energy sources by 2019, approximately 500 MW of which was to be from wind power sources.[19] No further updates or reports of the plan have been made official since, but the goal was not reached in the desired time frame. In response to the lack of attention from the Government to initiating new renewable energy projects, the country's scientists and non-governmental organizations (NGOs) have been on the forefront of pushing for the transition.[20]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The barriers to SHP development might also apply to the dissemination of other renewable energy resources. The current electricity sector crisis represents a constant reminder that SHP as well as other renewable energy sources may, in time, tackle the existent issues of the sector. Most noteworthy barriers to SHP are the following:

- Large hydropower is considered much more profitable than SHP and therefore there is limited interest in further implementing or investing in SHP projects;
- Due to multiple complaints and protests resulting from the lengthy electricity crisis, the Government of Venezuela mostly considers projects that could offer higher electricity coverage for the population;
- Lack of local expertise in the SHP sector as well as limited information on the actual SHP potential of the country;
- Limited information on the existent plants, their generation potential and whether an upgrading or refurbishment project is necessary.

Enablers to SHP development in Venezuela include:

- More SHP plants would lessen reliance on the major Simon Bolivar hydropower plant;
- As most hydropower plants are located in the eastern or southern regions, SHP development in the north-western region would lower transmission distance and could increase energy stability.

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2.4. Northern America

Countries: Canada, Greenland, United States of America

INTRODUCTION TO THE REGION

The electricity sectors of Canada, Greenland and the United States of America (USA) reflect the relative size of their economies and electricity demand. The USA is the second-largest producer and consumer of electricity in the world, after the People's Republic of China, and has a highly diversified energy mix for electricity generation that includes every major type of energy source in addition to a variety of emerging technologies. However, thermal power, primarily from coal and natural gas, still plays the main role in electricity production in the country, accounting for 67 per cent of installed capacity and 60 per cent of generation in 2020 while hydropower accounted for just 8 per cent of installed capacity and 7 per cent of generation. By contrast, hydropower forms the mainstay of electricity generation in both Canada and Greenland, providing 59 per cent of generation in Canada in 2019 and nearly 80 per cent in Greenland in 2020. Canada is one of the global leaders in hydropower generation and a net electricity exporter. The accessible hydropower resources of Greenland are limited relative to the mass of water stored in glaciers across the country, but are sufficient to provide for the energy needs of its small population.

The structure of the electricity sector in the USA is highly decentralized, with the national grid functionally operating as several independent grid regions and electricity markets and over 3,300 private and public electric utilities engaged in production, transmission and distribution of electricity across the country. In Canada, the electricity sector is dominated by provincial Crown corporations operating as vertically integrated utilities, with interconnections between provincial grids mainly running north to south and having limited interconnectivity across the east-west axis. The electricity sector in Greenland largely consists of mutually isolated mini-grids supplying power to individual settlements, although a single state-owned utility company is responsible for managing the entire sector.

An overview of the electricity sectors of the countries in the Northern America region is provided in Table 1.

Table 1. **Overview of Northern America**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Canada	38	N/A	N/A	145,000	640,400	N/A	377,600
Greenland	0.1	100	100	230	540	91	430
USA	333	100	100	1,212,300	4,007,100	101,900	280,000
Total	-	-	-	**1,357,530**	-	**101,991**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in Canada includes hydropower plants with an installed capacity of up to 50 MW, while in Greenland SHP refers to plants with a capacity of up to 5 MW. There is no nationwide definition of SHP in the USA.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Northern America (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (<10 MW)*	*Potential capacity (<10 MW)*
Canada	Up to 50 MW	4,504.0	15,000.0	N/A	N/A
Greenland	Up to 5 MW	N/A	N/A	9.0	183.1
USA	N/A	N/A	N/A	3,681.0	10,583.0
Total	-	-	-	**3,690.0**	**10,766.1**

Source: *WSHPDR 2022*[1]

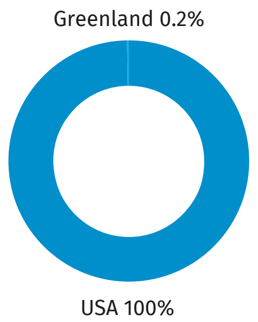
The total installed capacity of SHP up to 10 MW in Northern America is 3,690 MW, while potential capacity is estimated at 10,766.1 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has decreased by 22 per cent while estimated potential capacity has decreased by 9 per cent, due to a lack of recent data on SHP up to 10 MW in Canada.

Both Canada and the USA have robust SHP sectors, which nonetheless form only a small fraction of the total installed hydropower capacities of these countries. Both countries have very significant untapped SHP potential, although due to the differences in the definition of SHP used in each country, a direct comparison is not possible. The SHP sector in Greenland is smaller by several orders of magnitude but accounts for a relatively larger share of the country's total hydropower capacity.

The SHP sectors in the USA and Canada are both undergoing active development, with many new plants built in recent years. Although both countries are well-supplied with electricity, SHP is promoted as a means to decarbonize electricity generation and, particularly in Canada, as a means of providing renewable power to remote communities still isolated from provincial electricity grids. In Greenland, little SHP development has taken place over the last decade.

The national share of regional installed capacity for SHP up to 10 MW by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

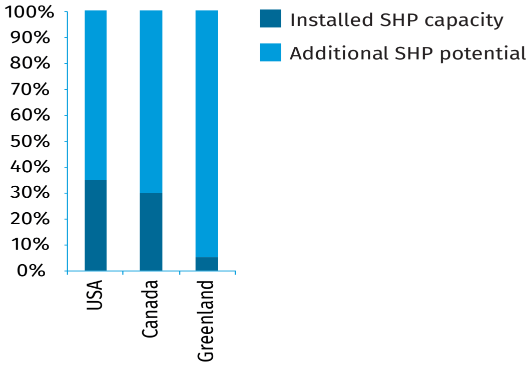
Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Northern America (%)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2019*[2]

Note: Canada is not included due to lack of data.

Figure 2. **Utilized Small Hydropower Potential by Country in Northern America (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP up to 10 MW, except in the case of Canada where the local definition is used due to the lack of recent data on SHP up to 10 MW.

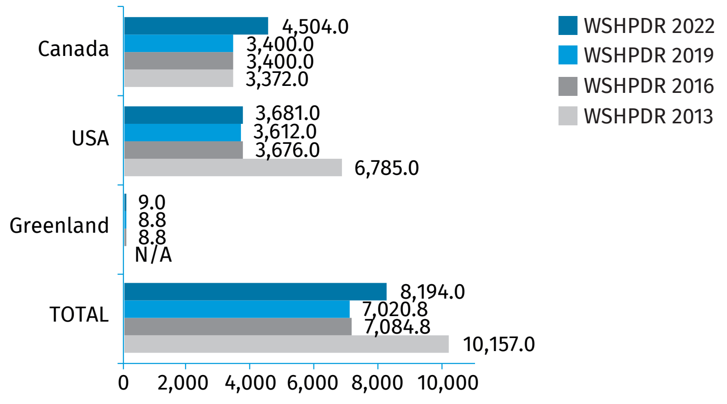
The total installed capacity of SHP in **Canada** was 4,504 MW for SHP up to 50 MW as of 2020, with a corresponding potential capacity of 15,000, indicating that 30 per cent has been developed. However, the estimate of SHP potential in the country is rather dated and based on unclear methodology, with an updated estimate currently under preparation. SHP construction in the country is very active, with several new plants commissioned every year. SHP development is spurred by the exhaustion of large hydropower potential in several provinces and ambitious decarbonization goals set by the national Government, particularly with regard to the phasing out of coal-fired power plants.

The total installed capacity of SHP up to 10 MW in **Greenland** is 9 MW, provided by two larger SHP plants as well as by a collection of micro-hydropower plants with a combined capacity of 200 kW. The SHP potential in the country is assessed at 183.1 MW, indicating that approximately 5 per cent has been developed. No new SHP construction has taken place since 2008, but one ongoing SHP project is planned to launch in 2023. Additional interest in SHP development in the country is mainly focused on micro-scale hydropower.

In the **USA**, the total installed capacity for SHP up to 10 MW was 3,681 MW as of 2021, provided by 1,679 SHP plants. The potential capacity of SHP up to 10 MW in the country is estimated at 10,583 MW, indicating that nearly 35 per cent has been developed so far. SHP development in the USA is actively ongoing as part of a general trend towards the development of renewable energy sources, as the federal, state and municipal governments have adopted clean energy targets and renewable portfolio standards (RPS), with several new SHP plants commissioned every year. Development of SHP in the country has focused on the construction of SHP plants on non-powered dams and water conduits, rather than new stream reaches. Private companies account for the majority of planned and proposed SHP projects, while public companies active in the sector are frequently municipalities interested in adding SHP capacity to non-powered water infrastructure they already own or operate.

Changes in the installed SHP capacities of the countries in the region compared to the previous editions of the *World Small Hydropower Development Report (WSHPDR)* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in Northern America (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR* 2016,[3] *WSHPDR 2019*[4]

Note: For SHP up to 10 MW, except in the case of Canada where the local definition is used due to lack of recent data on SHP up to 10 MW.

Climate Change and Small Hydropower

Across Northern America, runoff is anticipated to increase due to earlier snowmelt. With earlier snowmelt, lower summer flows are expected to diminish, which could reduce the hydropower generation in the summer months. Moreover, flood magnitude and frequency are increasing due to more frequent and more intense extreme precipitation events. This would require further investigation of potential impacts on seasonal and annual hydropower generation, as well as infrastructure risk assessment. In the USA, the fleet is expected to absorb part of the runoff variability due to the relatively large storage capacity. However, the undertaken analyses do not consider any other changes that could affect the capability to mitigate the runoff variability, such as the ageing of the fleet, water uses and environmental services.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In **Canada**, development of SHP is hindered by the lack of undeveloped economically feasible sites, which has eroded the cost-effectiveness of SHP in the country especially relative to other renewable energy sources. Additionally, a number of provincial programmes subsidizing SHP have been discontinued and a decrease in load growth has meant that the country is currently oversupplied with electricity. Opportunities for future development of SHP in Canada are considered to lie in the refurbishment of existing plants, ongoing replacement of capacities provided by thermal power and the provision of clean energy to remote communities. The regulatory framework of Canada is favourable to SHP development and public opinion is broadly supportive of SHP, provided sites are developed in consultation with local communities.

The main obstacles to SHP development in **Greenland** are the low demand for electricity and the lack of interconnections between communities, as well as a focus on the development of larger hydropower projects to provide for future energy needs. Enablers for development in the sector include the large untapped SHP potential and broad support for decarbonizing the country's energy mix, as well as the provision of government loans for all hydropower projects.

Barriers to SHP development in the **USA** include regulatory obstacles, lack of universal standards, risk aversion on the part of owners of water infrastructure and competition from other sources of power generation. Despite this, the environment for SHP development in the country is generally favourable. On a national scale, increased attention to renewable energy development, legislation promoting renewable energy targets and expediting SHP licensing, as well as technical innovations that are likely to reduce costs and increase the efficiency of SHP construction and operation are all driving active development in the sector. Incentives differ by state and locale but can include feed-in tariffs and access to net energy metering. Tax incentives for SHP are provided at the federal level as well as by some states.

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Canada

Richard Hendriks and Bryan Karney, University of Toronto

KEY FACTS

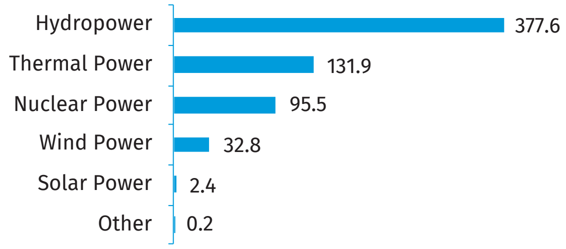
Population	38,008,005 (2020)[1]
Area	9,984,670 km^2 [2]
Topography	Canada is topographically and geographically diverse.[3] Along the Pacific coast, the Western Cordillera includes the Coastal Mountain and Rocky Mountain ranges, consisting of deep, glaciated river valleys, snow-topped mountain peaks and cold, glacier-fed rivers. Extending from Yukon territory through British Columbia and Alberta to the United States of America (USA), the Rocky Mountains include Mount Logan, the country's highest point at 5,959 metres above sea level.[2] The Interior Plains are dominated by flat crop and grazing lands, native grasslands and meandering rivers. Further east and north, the Canadian Shield is characterized by forested and rocky uplands and plateaus drained by an extensive network of lakes and rivers into Hudson Bay and its lowlands. The geologically ancient Appalachian Uplands, consisting of forested highlands and pastoral river valleys, extend south of the St. Lawrence Lowlands and across the Atlantic region. At over 240,000 km, the country has the world's longest coastline.[2]
Climate	The Canadian climate is highly variable.[4] Along the western coast, the Pacific maritime region has high precipitation, cool winters and warm summers, while the interior prairie region east of the Rocky Mountains experiences more extreme seasonal temperatures and less precipitation. The boreal region, extending across much of the country, has a continental climate — dry and humid summers with long, dry and very cold winters. The inland Great Lakes moderate the climate in the south-central regions, while the Atlantic maritime region along the eastern coast experiences moderate precipitation with cold winters and cool summers. Much of the far north is tundra with frigid winters and short summers. Average temperatures in summer range from 6 to 20 °C and in winter from -30 to +5 °C.[5]
Climate Change	Climate change is anticipated to increase annual precipitation in the coming decades while decreasing snowfall in almost all regions of the country. By the middle of this century, mean temperatures are forecast to increase moderately (by 2–3 °C) in the southern regions of the country and more extremely (by 3–5°C) in the northern regions.[6]
Rain Pattern	In the Pacific maritime region, annual precipitation ranges from 1,500 to 3,000 mm, almost entirely as rainfall.[4] The dryer interior prairies and northern boreal receive 300–800 mm of precipitation annually, with the Great Lakes – St. Lawrence region receiving 500–1000 mm.[5] Further north and away from open waters, precipitation has historically been dominated by snowfall.[6]
Hydrology	The country's two million freshwater lakes and more than 8,500 rivers encompass over 890,000 km^2, more than 9 per cent of the total area.[7,8] Twelve rivers extend more than 1,000 km, the longest being the Mackenzie River (4,250 km), which drains an area exceeding 1,800,000 km^2 into the Arctic Ocean. Twenty-four rivers have drainage areas exceeding 100,000 km^2, while 23 rivers have annual average discharges exceeding 1,000 m^3/s, with the highest being the St. Lawrence River with an average flow of 9,850 m^3/s.[8,9]

ELECTRICITY SECTOR OVERVIEW

The electricity generation sector in Canada had a total installed capacity exceeding 145 GW in 2017 and generated 640 TWh in 2019 (Figure 1), while exporting 60.3 TWh and importing 13.3 TWh to and from the USA.[10,11] Hydropower is the primary source of electricity generation providing 377.6 TWh, or 59 per cent of electricity nationally in 2019.

The share of electricity generated from renewable resources increased between 2010 and 2019 from 62 per cent to almost 65 per cent, while the share of non-emitting resources increased from 77 per cent to 79 per cent.[12] Six of ten Canadian provinces, comprising over 80 per cent of the population, produce almost all their electricity from non-emitting sources. Growth in generation from renewable sources, including hydropower, is expected to be focused on new generation within or supplying those provinces (Alberta, Saskatchewan, Nova Scotia and New Brunswick) where significant decarbonization of the grid remains essential to meeting the nation's commitments to reducing greenhouse gas (GHG) emissions.[1]

Figure 1. **Annual Electricity Generation by Source in Canada in 2019 (TWh)**



Source: Statistics Canada[11]

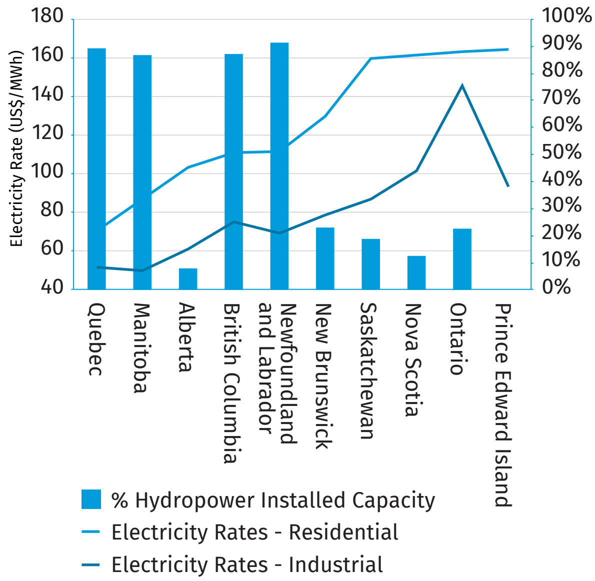
Over the past decade, Canada annually exported an average of 10 per cent of electricity generated, while importing an average of 2 per cent of electricity consumed.[11] Electricity services are available in all regions of the country, with 99.5 per cent of Canadians receiving electricity from locations on the interconnected Northern American grid and the remainder from remote micro-grids.[13]

The electricity sector of Canada is dominated by provincial Crown corporations operating as vertically-integrated utilities that own, control and plan generation, transmission and distribution. They are regulated by provincial utility boards.[14] This is exclusively the case in provinces (British Columbia, Manitoba, Québec and Newfoundland and Labrador) where large proportions (over 90 per cent) of electricity are generated by hydropower resources. Two of the provinces (Alberta and Ontario) have competitive markets, while the remainder have either Crown or private sector monopoly utilities. The Federal Government, through the Canada Energy Regulator (CER), retains jurisdiction for the issuance of permits for inter-provincial and international transmission lines, as well as the environmental assessment of international (>345 kV) and interprovincial (when designated by a CER order) transmission lines and any large-scale hydropower developments (>200 MW).[15,16]

Canada has a primarily north-south transmission network, intra-provincially and internationally, with limited transmission east-west between provinces. Five provinces (British Columbia, Manitoba, Ontario, Québec and Newfoundland and Labrador) have developed extensive northern hydropower resources and extra high voltage transmission to deliver electricity to southern load centres. A total of 49 transmission lines (over 60 kV) interconnect Canada to the United States, including the Manitoba-Minnesota Transmission Project, a 500 kV transmission line completed in June 2020.[17] Numerous recent studies have recommended expansion of the east-west transmission grid in support of system decarbonization.[18,19,20] Specifically, these studies advocated increasing interconnections between provinces dominated by dispatchable hydropower generation and those seeking to reduce dependence on coal generation while developing more intermittent renewable sources.

As a result of significant historical investment in hydropower resources, households and industry in Canada enjoy some of the lowest electricity prices within the Organization for Economic Cooperation and Development (OECD).[21] The benefits of this investment are most evident in those provinces in which hydropower resources make up a substantial proportion of total installed capacity, as shown in Figure 2.[10,22] With the noted exception of Alberta, which benefits from substantial electricity from lower-cost co-generation, the lack of additional low-cost hydropower potential in New Brunswick, Saskatchewan, Nova Scotia, Ontario and Prince Edward Island led to a reliance on thermal generation (fossil fuel and nuclear), resulting in higher production costs.

Figure 2. **Share of Hydropower in Total Installed Capacity (%) vs. Electricity Rates by Province in Canada in 2017 (USD/MWh)**



Source: Statistics Canada,[10] Hydro Québec[22]

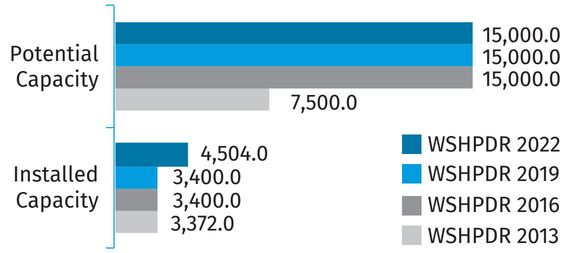
Historically, electricity prices in Canada have changed little with inflation over the past four decades. The only exception is the 1990s when several provinces, including Ontario and British Columbia, froze electricity rates.[23,24] In provinces with utility monopolies, responsibility for regulating electricity rates rests with provincial utility boards. Typically, these boards have a mandate for approving capital expenditures, reviewing financing and amortization costs, determining revenue requirements and establishing fair and reasonable electricity rates for ensuring safe and reliable access to electricity.[25,26] In the two provinces with competitive markets (Ontario and Alberta), residential and commercial customers have the choice of purchasing electricity from regulated retailers or from competitive retailers based on wholesale market prices, while industrial customers purchase directly from the wholesale market.[27,28]

SMALL HYDROPOWER SECTOR OVERVIEW

In Canada, there are several categories of small hydropower (SHP): micro-hydropower (less than 100 kW), mini-hydropower (100 kW – 1 MW) and small hydropower (1 MW – 50 MW).[29] Depending on the particulars of a given site, SHP facilities can be connected to the interconnected transmission system at voltages greater than 60 kV, to an interconnected distribution system at voltages lower than 60 kV or to a remote micro-grid at the appropriate system voltage.

As of 2020, the installed capacity of SHP (up to 50 MW) in Canada was 4,504 MW, excluding facilities under development.[30,31,32,33,34,35,36,37] The technical potential capacity was previously estimated by the Canadian Hydropower Association (now Waterpower Canada) to be 15,000 MW, or approximately 40–60 TWh/year depending on operational capabilities and capacity factors.[38] The underlying methodology for determining this estimate is not known; however, updated estimates are in preparation by Waterpower Canada.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Canada (MW)**



Source: BC Hydro,[30] Alberta Electric System Operator,[31] Independent Electricity System Operator,[32] Hydro Québec,[33,34] Newfoundland Power,[35] North American Cooperation on Energy Information,[36] Power Advisory LCC,[37] *WSHPDR 2013*,[39] *WSHPDR 2016*,[40] *WSHPDR 2019*[41]

Note: Data for SHP up to 50 MW.

The over 4,500 MW of SHP capacity (up to 50 MW) accounts for 5.5 per cent of total installed hydropower capacity in Canada. There are currently 447 operational SHP plants (up to 50 MW) in Canada with 317 of these having an installed capacity of not more than 10 MW.[36] This compares with 3,400 MW of SHP capacity (up to 50 MW) reported in the *World Small Hydropower Development Report* (*WSHPDR*) 2019 (Figure 3), which accounted for 4.2 per cent of national installed hydropower capacity. The change in the reported installed SHP capacity (up to 50 MW) primarily reflects access to better data, particularly for plants smaller than 1 MW, as well as reconciliation between utility and government sources, which had previously underreported the capacity of installed SHP. Since the *WSHPDR 2019*, which reported data to the end of 2017, the installed capacity of SHP capacity (up to 50 MW) increased by over 80 MW with the development of eight new plants (Table 1), while another seven plants totalling more than 50 MW are under development (Table 2).

Table 1. **List of Selected Operational Small Hydropower Plants in Canada**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Elliot Falls Expansion	Norland, Ontario	0.1		Run-of-river	Elliot Falls Power Corporation	2020
Little Burgess Expansion	Bala, Ontario	0.2		Run-of-river	KRIS Renewable Power Ltd.	2020
North Bala	Bala, Ontario	5.0	6.2	Run-of-river	Swift River LP	2020
Narrows Inlet	Sechelt, British Columbia	33.0	324.0	Run-of-river	tems sayamkwu Limited Partnership	2019
Winchie Creek	Ucluelet, British Columbia	4.0	156.5	Run-of-river	Winchie Creek Hydro Limited Partnership	2019
Yellow Falls	Smooth Rock Falls, Ontario	16.0	12.0	Run-of-river	Yellow Falls Power Limited Partnership	2019
Hunter Creek	Hope, British Columbia	11.0		Run-of-river	Hunter Creek Hydro Limited Partnership	2018
Trio Kwalsa	Mission, British Columbia	13.8		Run-of-river	Harrison Hydro Limited Partnership	2018
Namewaminikan	Beardmore, Ontario	10.0		Run-of-river	Namewaminikan Hydro Inc	2017
Norland Dam	Coboconk, Ontario	0.5		Run-of-river	Timber Run Hydropower Corporation	2017
Norman Expansion	Kenora, Ontario	2.7		Run-of-river	H2O Power LP	2017
Smooth Rock Falls Expansion	Smooth Rock Falls, Ontario	2.2		Run-of-river	Gemini-SRF Power Corporation	2017
Mistassini	ND de Laurette et Girardville, Québec	18.3		Run-of-river	Société en commandite Énergie Hydroélectrique Mistassini	2017
Big Silver	Harrison Hot Springs, British Columbia	40.6		Run-of-river	Big Silver Creek Power Limited Partnership	2016
Lorenzetta Creek	Laidlaw, British Columbia	3.2		Run-of-river	Zella Holdings Ltd.	2016
Silversmith Power & Light	Sandon, British Columbia	1.0		Run-of-river	Silversmith Power & Light Corporation	2016

Name	Location	Capacity (MW)	Head (m)	Plant type	Operator	Launch year
Canton Mill	Port Hope, Ontario	0.1		Run-of-river	Ian W. M. Angus	2016
Gitchi Animki Bezhig	Mobert, Ontario	12.0	14.0	Run-of-river	Pic Mobert Hydro Inc	2016
Gitchi Animki Niizh	Mobert, Ontario	10.0	21.0	Run-of-river	Pic Mobert Hydro Inc	2016
London Street Expansion	Peterborough, Ontario	5.9		Run-of-river	Peterborough Utilities Inc.	2016

Source: BC Hydro,[30] Independent Electricity System Operator,[28] Hydro Québec,[33,34] North American Cooperation on Energy Information,[36]

Table 2. **List of Selected Ongoing/Planned Small Hydropower Projects in Canada**

Name	Location	Capacity (MW)	Plant type	Developer	Planned launch year	Development stage
Manouane Sipi	Manouane	22.0	Run-of-river	Ville de La Tuque / Atikamekw de Wemotaci	2023	Pre-construction
Winston	St-Antoine de Riviere du Loup	2.5	Run-of-river	Winston Hydro	2023	Pre-construction
Chute du Quatre Milles	Forestville	5.5	Run-of-river	Énergie Hydroélectric Pessamit	2022	Construction
Chute du Six Milles	Forestville	13.2	Run-of-river	Énergie Hydroélectric Pessamit	2022	Construction
Little Rapids	Iron Bridge	0.3	Run-of-river	Gravel Power Corp	2022	Construction

Source: Independent Electricity System Operator,[32] Hydro Québec,[33,34]

As the development of large-scale hydropower projects concludes in several provinces, the focus is shifting to evaluating and investing in the refurbishment and expansion of existing hydropower infrastructure. As shown in Table 1, five expansions at existing SHP facilities were recently completed in Ontario. Other refurbishments and expansions are planned in different provinces.

While nearly all Canadians receive electrical service from the interconnected Northern American grid, nearly 200,000 residents in a total of 276 remote communities are serviced primarily by diesel generators (201 communities), micro-grids (26 communities) and remote hydropower generation (35 communities), including 19 SHP plants.[42] The outsized GHG emissions from remote diesel-powered communities represent an opportunity for emissions displacement by renewable forms of electricity generation, including SHP.

Provincial utilities have identified numerous SHP projects for potential development pursuant to resource planning and resource adequacy studies. The potential SHP projects summarized in Table 3 have been studied to various levels of pre-feasibility.

Table 3. **List of Potential Small Hydropower Sites in Canada**

Name	Location	Potential capacity (MW)	Head (m)	Type of site (new/refurbishment)
Tazi Twe	Fond du Lac River, Saskatchewan	50	36	New
Red Indian Falls	Exploits River, Newfoundland and Labrador	42	23	New
Island Pond	North Salmon River, Newfoundland and Labrador	36	25	New
Portland Creek	Main Port Brook, Newfoundland and Labrador	23	395	New
Round Pond	Bay D'Espoir, Newfoundland and Labrador	18	11	New

Source: CEAA,[43] Newfoundland and Labrador Hydro[44]

RENEWABLE ENERGY POLICY

The 2016 Pan-Canadian Framework on Clean Growth and Climate Change was an important step to achieving the country's commitment in the Paris Agreement to reduce GHG emissions by 30 per cent from 2005 levels by 2030.[45] Acknowledging that non-emitting electricity sources are foundational to deep decarbonization, the Framework aimed to increase the proportion of electricity generated from renewable and low-emitting sources, modernize electricity systems and reduce reliance on diesel generation in northern and remote communities.[45] Pursuant to the Framework, Environment and Climate Change Canada amended the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations in December 2018.[46] Of the 36 operating coal units as of 2017, the Regulations were expected to result in the shutdown or conversion to natural gas generation of 26 units by 2030, representing a combined generating capacity of nearly 8,000 MW.[46] Of the remaining units, six are expected to be shuttered by 2045 and the rest by 2065.

In December 2020, the Government of Canada released A Healthy Environment and a Healthy Economy plan, outlining the remaining proposals for achieving the country's commitments in the Paris Agreement. In terms of electricity, this report targets increasing the proportion of non-emitting electricity resources to 90 per cent by 2030 and to net-zero emissions by 2050.[47] Under a scenario in which significant electrification occurs across the economy, achieving this goal will require at least doubling generation from renewable sources of electricity.[47] The proposed gradual escalation of the carbon price from 50 USD/tCO_2e in 2022 to 170 USD/tCO_2e in 2030 will encourage further fuel-switching from emission-intensive heating, transportation and industrial processes towards those powered by lower-emitting electricity generated primarily from renewables.[48]

Provincially, British Columbia has shifted focus to the construction of the 1,100 MW Site C Project, a large-scale hydropower plant.[49] This resulted in discontinuing more than a decade of smaller-scale wind, hydropower and biomass development by independent power producers pursuant to a series of power calls initiated by the provincial utility, BC Hydro.[50,51] Alberta has committed to eliminating coal-fired electricity while adding a minimum of 5,000 MW of wind and solar power capacity by 2030, of which more than 2,000 MW is already approved, under construction or operating.[52,53] Saskatchewan is annually developing on the order of 100 MW of wind power and 20 MW of solar power, as Manitoba Hydro completes construction of the 695 MW Keeyask hydropower plant.[54] As a result, neither province is currently pursuing available SHP potential. Following the shuttering of its last coal facility in 2015, Ontario saw further development of 455 MW of SHP, wind and solar power pursuant to its large renewable procurement process, which concluded in 2016 with some approved SHP projects still under construction.[55] In Québec, several SHP plants are planned or under construction (Table 2), though new SHP procurement is not currently planned.[56] Nova Scotia recently commissioned the Maritime Link, a high-voltage direct current subsea cable from Newfoundland to deliver electricity from the recently completed 824 MW Muskrat Falls Project in Labrador while facilitating an export market for future development of SHP potential in Newfoundland.[57]

With the improving cost competitiveness of onshore wind and utility-scale solar generation across Canada, provincial governments and utilities have stepped back from programmes designed specifically to promote renewable generation. Feed-in tariff (FIT) programmes in Ontario and Nova Scotia have discontinued and dedicated renewable energy procurement programmes in British Columbia, Alberta and Ontario have concluded.[50,52,58,59,60] Due to continuing declines in costs, onshore wind and utility-scale solar generation are increasingly being developed outside of incentive programmes as distributed self-generation or as utility-scale resources competing directly in electricity markets.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

No province in Canada currently has initiatives aimed specifically at the development of new SHP projects. At the same time, recent SHP development in Canada has included more than a dozen projects (up to 50 MW) of which several remain in planning or construction as shown in Table 3.[61]

Pursuant to the country's climate policy, Natural Resources Canada's recent ongoing investment programmes relevant to SHP include:

- Clean Energy for Rural and Remote Communities Programme: supports a suite of programmes that aim to reduce reliance on diesel fuel in rural and remote communities, including by directly funding expansion and refurbishment of existing SHP plants;
- Energy Innovation Programme: supports clean technology research and development, including clean energy planning in several remote communities proximal to potential future SHP development;
- Northern Responsible Energy Approach for Community Heat and Electricity Programme: funds renewable energy and efficiency projects in the northern territories of Canada, including assessments and feasibility studies of hydropower projects.[62,63,64]

SHP projects do not require environmental assessment at the federal level though federal departments have jurisdiction in relation to fish and fish habitat, species at risk and migratory birds.[65] The licensing process for SHP varies provincially, and typically involves environmental assessment, permitting in relation to facility construction and operations as well as ongoing environmental protection, monitoring and enforcement.

COST OF SMALL HYDROPOWER DEVELOPMENT

Provincial utilities report preliminary cost estimates for potential hydropower development sites within resource planning and resource adequacy studies. Levelized costs of energy for some of the more cost-effective SHP sites up to 50 MW are provided in Table 4, illustrating a cost on the order of 110–140 CAD/MWh (87–111 USD/MWh). These costs compare to typical levelized costs of 30–60 CAD/MWh (24–48 USD/MWh) for onshore wind resources in Canada.[66,67]

Table 4. **Small Hydropower New Facility Levelized Cost of Energy**

Project Name	*Location*	*Potential capacity (MW)*	*Average annual generation (GWh)*	*Site type*	*Capital costs (CAD/MW (USD/MW))*	*Levelized costs (CAD/MWh (USD/MW))*	*Study level*
Badger Chute	Exploits River, Newfoundland and Labrador	24	154	New	–	125 (99)	Screening

Project Name	Location	Potential capacity (MW)	Average annual generation (GWh)	Site type	Capital costs (CAD/MW (USD/MW))	Levelized costs (CAD/MWh (USD/MW))	Study level
ROR_110-120_BQL	North Coast, British Columbia	45	158	New	2.31 (1.83)	128 (101)	Screening
ROR_110-120_NC	North Coast, British Columbia	38	135	New	2.66 (2.11)	128 (101)	Screening
ROR_120-130_MCA	Mica, British Columbia	29	104	New	3.39 (2.68)	137 (108)	Screening
ROR_120_130_EK	East Kootenay, British Columbia	47	147	New	3.76 (2.98)	138 (109)	Screening
ROR_120-130_SE	Selkirk, British Columbia	28	88	New	3.12 (2.47)	139 (110)	Screening
ROR_120-130_VI	Vancouver Island, British Columbia	26	116	New	3.53 (2.80)	139 (110)	Screening
ROR_120-140_NC	North Coast, British Columbia	24	90	New	2.98 (2.36)	139 (110)	Screening

Source: BC Hydro,[67] Newfoundland and Labrador Hydro[46]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Financing of SHP projects is generally through the private sector, since recent smaller-scale renewable energy projects in Canada are almost exclusively developed by independent power producers. Since subsidies and incentives for the development of renewable sources are increasingly no longer required to ensure competitiveness with conventional generation, particularly for onshore wind and solar power generation, SHP projects in Canada now compete against these other renewable technologies in direct procurement processes or in competitive electricity markets. Generally, this has resulted in less development of greenfield SHP projects, a trend that is anticipated to continue into the foreseeable future. The one exception is remote communities where federal programmes support the development of suitable SHP sites since the potential for other non-emitting alternatives is limited.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Existing SHP facilities in Canada have enjoyed relatively consistent climate and hydrological conditions over the past century. In the coming decades, the climate crisis is anticipated to increase annual precipitation by 5–15 per cent depending on location and future climate conditions, while also decreasing winter snowfall in almost all regions of Canada.[6] By the middle of this century, mean temperatures are forecast to increase by 2–3 °C in the southern regions of the country and by 3–5 °C in the northern regions.[6] Runoff is anticipated to increase into many of the country's important hydropower watersheds, with earlier snowmelt, a larger and earlier spring freshet and lower late summer and fall hydrologic flows.[68,69] Climate adaptation actions to date have included hydrology and glaciology impact studies, investigations of potential implications for seasonal and annual hydropower generation, as well as infrastructure risk assessments.[68]

Within Canadian climate policy, the emphasis on low-carbon electrification as a means to decarbonize the economy is anticipated to result in growing electricity demand over at least the next two decades. Provincial utilities that have included the effects of policies addressing low-carbon electrification are forecasting annualized average growth on the order of 0.5–1.0 per cent per year over the next two decades depending on the degree of electrification, rates of economic growth and other factors.[70,71] The effort to decarbonize the grid has been aided by electricity demand, which has remained relatively unchanged in Canada as a whole over the past decade. Annualized average growth was 0.3 per cent from 2007 through 2019, compared to 1.3 per cent per year for the period 1990–2007 and 5 per cent per year in the period 1960–1990.[11] The COVID-19 pandemic has resulted in a material decrease in electricity demand that is not expected to fully recover for at least five years.[72,73] Demand-side management measures are implemented in almost all provinces through combinations of codes, standards, programmes and conservation rates implemented by utilities or independent agencies. Energy savings performance in 2019 varied by province from less than 0.1 per cent to more than 1.2 per cent of annual domestic electricity sales with national savings averaging 0.4 per cent.[74] This compares to more than 2 per cent of annual domestic sales in some USA states and national average savings of 0.7 per cent of electricity sales across the USA, suggesting that Canada has considerable additional electricity conservation and efficiency potential.[75]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Future new greenfield SHP development remains limited to isolated grid-connected sites that offer storage and provision of dependable capacity and dispatchability and to remote sites where development of competing alternatives is not technically or economically feasible. Refurbishment, including capacity additions and upgrades, of existing sites is likely to prove economic in most instances with only a few facilities being decommissioned.

There are several barriers to additional SHP development in Canada:

- Cost-effectiveness: The most technically and economically feasible SHP sites in Canada have already been developed. The recent and anticipated future declines

in the cost of energy from onshore wind and solar photovoltaics continue to erode SHP cost-competitiveness;
- Discontinued programmes and subsidies: The conclusion of prior FIT programmes, targeted subsidy programmes and targeted power calls at the provincial level result in a policy environment less supportive of SHP development;
- Low load growth: Load growth was already low in Canada in the decade prior to the pandemic. Post-pandemic, load is not anticipated to fully recover for at least five years, further deterring investment in SHP in the short to medium term.

In terms of the potential for refurbishment of existing SHP plants, Nova Scotia Power recently reviewed its entire hydropower fleet consisting of over 30 SHP plants totalling 169 MW of installed capacity.[76] This review and related analyses indicated that while refurbishment of much of the fleet is cost effective, some facilities are no longer considered used and useful and several others require further review to determine cost-effectiveness prior to investment in refurbishment.[73,77] BC Hydro determined in its most recent integrated resource plan that only 75 per cent of existing contracted hydropower plants (many of which are SHP plants) would be re-contracted.[78] This recognizes declines in the costs of competing resources, the high cost of refurbishment at some locations and the lower value of energy generated by non-storage hydropower during the spring freshet when its output is often surplus to requirements.

There are several enablers to additional SHP development in Canada:
- Regulatory support: The regulatory frameworks and licensing processes for SHP are mature across Canadian provinces and generally favourable to additional SHP development, while no environmental assessment required at the federal level;
- Low-carbon electrification: In the medium to long term, increasing electricity demand in support of low-carbon electrification will spur further investment in SHP, particularly in refurbishment and expansions at existing SHP plants;
- Public support: SHP remains one of the lowest-impact means of producing low-carbon electricity and continues to enjoy strong public support in Canada, particularly when sites are developed in consultation and collaboration with local and indigenous communities.

Overall, the competitive position of SHP suggests that, in the absence of future programmes targeting development, significant quantities of new SHP projects are unlikely to be developed. Natural Resource Canada's current programmes supporting the development of SHP to service diesel-dependent remote communities currently represent the primary enabler of SHP development in Canada.

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Greenland

Asger Dall, Nukissiorfiit; and Kenneth Bengtson Tellesen Primdal, Ministry of Fisheries, Hunting and Agriculture

KEY FACTS

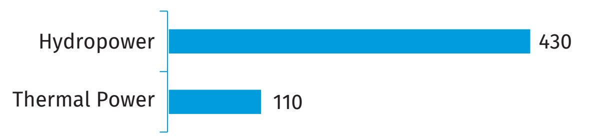
Population	56,421 (2021)[1]
Area	2,166,086 km^2 [1]
Topography	With two thirds of the island lying within the Arctic Circle, a flat, gradually sloping ice cap covers all but a narrow, mountainous, barren, rocky coast. The ice cap is up to 3 kilometres thick and contains 10 per cent of the world's resources of fresh water. Mountain chains run along the eastern and western coasts, with the highest peak, Gunnbjørn Mountain in the south-east, reaching 3,700 metres above sea level.[1,2]
Climate	The climate is Arctic to sub-Arctic, with a subtle influence of the Gulf Stream in the south-west. Winters are cold with average temperatures ranging from -7 °C in the south to -34 °C in the north. Summers are cool with mean temperatures normally not exceeding 10 °C.[2]
Climate Change	Temperature measurements carried out in south-west of Greenland since 1784, show an increasing trend, with the five warmest decades all having occurred in the last 100 years.[3] Between 1991 and 2019, an overall temperature increase of 4.4 °C was recorded in winter, of 2.7 °C in spring and of 1.7 °C in summer. The most significant warming trend has been observed in the west and north-west of the country, with up to 6–6.5 °C higher temperatures in winter. By the end of the century, temperatures are projected to increase by 5–7 °C.4 High-emission scenarios suggest that the melting of the Greenland ice sheet can contribute 9.9–17.8 centimetres to the global sea level rise. Rainfall is also projected to increase significantly.[5]
Rain Pattern	Much of the precipitation comes in the form of snow. Average annual precipitation ranges from 50 mm in the north to 1,900 mm in the south. Large areas of Greenland can be classified as Arctic deserts due to limited precipitation.[2]
Hydrology	Many of the hydropower potentials in Greenland depend on ablation from the ice cap. There are no large rivers in the country, the most significant one being the Børglum Elv in the north-east of the island.

ELECTRICITY SECTOR OVERVIEW

All towns and settlements in Greenland are running on isolated grids. The only exception are the towns of Qaqortoq and Narsaq in the south, which are both connected to the Qorlortorsuaq hydropower plant. Hydropower plants also power four other towns, but all other locations depend on electricity from diesel power plants. The state-owned utility company, Nukissiorfiit, is responsible for production and distribution of energy and water to all 17 towns and 53 settlements. In the south of Greenland, there are approximately 40 farms, not supplied by Nukissiorfiit. The farms are very isolated and therefore need their own energy supply. Most of them use diesel generators, but more are starting to use renewable energy, such as micro-scale hydropower and solar power.

Total installed capacity is approximately 230 MW.[6] Out of this, hydropower plants account for 91.3 MW. Additionally, in 2021, there was approximately 590 kW of solar power capacity and 50 kW of wind power capacity.[7] Total electricity generation in 2020 was approximately 540 GWh, of which hydropower accounted for almost 80 per cent, with the rest coming from diesel combustion (Figure 1).[8]

Figure 1. **Annual Electricity Generation by Source in Greenland in 2020 (GWh)**



Source: Statistics Greenland[8]

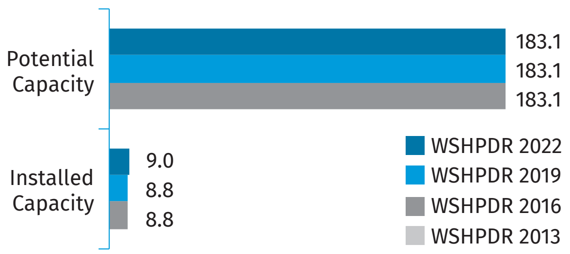
Greenland has universal electricity access.[9] The Government regulates the electricity tariffs. In 2018, the price structure was reformed and all private customers now pay the same price of 1.65 DKK/kWh (0.23 USD/kWh).[7] The fishing industry is subsidized with a discounted tariff, set at 41.5 per cent of the local production cost, but never higher than what the customers pay.

SMALL HYDROPOWER SECTOR OVERVIEW

Nukissiorfiit defines all hydropower plants above 5 MW as regular hydropower, whereas plants below 500 kW are defined as micro-hydropower and plants of 500 kW–5 MW capacity are defined as mini-hydopower.[7] Nationally, a distinction is often made between large hydropower for industrial use (above 100 MW), hydropower for supplying towns (1–50 MW) and settlements (below 1 MW) and micro-hydropower plants at off-grid farms (below 100 kW). This chapter will follow the 10 MW definition of small hydropower (SHP) for the purposes of comparison with the pervious editions of the *World Small Hydropower Development Report (WSHPDR).*

Following the 10 MW definition, there are two SHP plants (Table 1). In addition, there are at least seven active micro-hydropower plants with an estimated combined capacity of approximately 200 kW at off-grid farms in southern Greenland. Thus, total SHP installed capacity is approximately 9 MW, whereas the potential has been estimated at 183.1 MW.[6,10] Compared to the *WSHPDR 2019,* the installed capacity increased due to the inclusion of the micro-hydropower capacities, whereas the potential has remained unchanged (Figure 2).

Figure 2. **Small Hydropower Capacities in the WSHPDR 2016/2019/2022 in Greenland (MW)**



Source: Dall & Primdal,[6] *WSHPDR 2016,*[10] *WSHPDR 2019*[11]

Table 1. **List of Selected Existing Small Hydropower Plants in Greenland**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Operator*	*Launch year*
Qorlortorsuaq	Southern Greenland	7.6	128	Nukissiorfiit	2008
Tasiilaq	Eastern Greenland	1.2	100	Nukissiorfiit	2004

Source: Dall & Primdal[6]

Hydropower plants in Greenland operate on different grids and are sized according to the local needs. Therefore, even the smallest plants play an important role in the energy supply of local towns. In 2019, the Qorlortorsuaq and Tasiilaq SHP plants generated a total of approximately 33 GWh.[6] In addition to these two plants, there is one additional plant operating at less than 10 MW capacity. The hydropower plant in Sisimiut is equipped with two 7.5 MW turbines. One turbine is however enough to handle the peak load and there is a limited water resource. Therefore, the production very rarely exceeds 10 MW. In 2019, the Sisimiut plant generated 41 GWh.[6]

With the ice cap covering over 80 per cent of the total land area, Greenland has a large theoretical hydropower potential. The annual runoff is estimated to have an energy production potential in the order of 460–800 TWh. However, only a fraction of this energy is technically viable and even less is economically feasible.[12] Serious interest in developing the hydropower resources in Greenland started in the early 1970s. The initial mappings used topography maps to identify the biggest potentials. Later in the 1970s the first measurement stations were established. This effort intensified in the 1980s, with many field trips and detailed surveys carried out. At the same time, many of the most promising potentials had concepts drawn up. All of the sites identified and described are listed in an inventory from 2005.[13]

Greenland aims to expand hydropower capacity to reduce the use of fossil fuels for electricity generation. This includes larger-scale projects (55 MW expansion of the 45 MW Buksefjorden hydropower plant and construction of a new 21 MW plant at the fjord Kangersuneq approved in 2021), but also micro-hydropower projects.[14] Nukissiorfiit is looking to expand its renewable energy fleet with micro-hydropower projects and for this purpose has studied the existing micro-hydropower potentials. Kulusuk and Narsarmijit were identified as the villages with the best potential. The plant at Kulusuk is to be commissioned in 2023 and will supply the airport.[15]

RENEWABLE ENERGY POLICY

Naalakkersuisut, the Government of Greenland, has set the direction for the country's energy sector and Nukissiorfiit. The goal is to transition to renewable energy and that by 2030 the public energy supply must be, to the fullest extent possible, derived from renewable energy sources.[16]

Naalakkersuisut has also released a new strategy for the development of agriculture in Greenland in 2020, with a focus on increasing the use of hydropower by the farmers. Through better substitution opportunities for farmers, the Government will increase the incentive to invest in hydropower.

A number of private consumers and companies in the country have solar photovoltaics installed. In towns and settlements not already supplied with renewable energy from hydropower, excess electricity can be sold to Nukissiorfiit at a rate of 0.74 DKK/kWh (0.10 USD/kWh).[17]

All sizeable projects in Greenland are subject to an Environmental Impact Assessment (EIA). The Government organizes public hearings and has to approve the EIA before construction can start.

COST OF SMALL HYDROPOWER DEVELOPMENT

The construction costs of SHP projects vary widely from site to site. Since there is no centralized grid, the local energy consumption and the distance from the site to the town become very important parameters.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

All hydropower projects in the country have so far been funded by loans from the Government.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

With increasing ablation from the ice cap, the available water resources also increase. However, this mainly affects the large hydropower potential with catchments bordering the ice. The SHP potential is often concentrated closer to the towns in coastal areas and mainly depends on precipitation and melt-off from local glaciers. However, there have been observed some changes, with local glaciers disappearing and rain patterns shifting. This leads to increased runoff in some areas, while others are becoming drier, but this varies from site to site and is less conclusive.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

So far, only a few SHP projects have been developed in Greenland, with some of the reasons listed below:

- Even the bigger towns and settlements in Greenland are small communities with only a few hundred to a couple of thousand people. Hence, the energy demand in any single place is limited;
- Long distances make it cost prohibitive to connect multiple settlements together;
- Difficult terrain and limited infrastructure lead to high construction costs.

The key enabling factors for SHP development in the country include:

- Large hydropower potential;
- Policy support for reducing fossil fuel use in favour of renewable energy with a particular focus on hydropower;
- Great support for hydropower in the local communities.

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United States of America

Anik Masfiqur Rahman, Ontario Power Generation

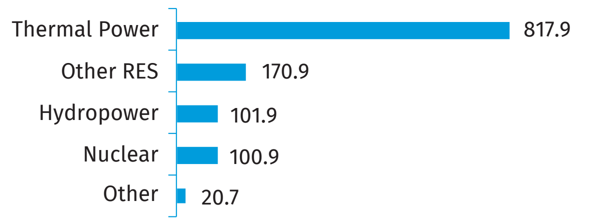
KEY FACTS

Population	332,457,501 (2022)1
Area	9,833,517 km2 2
Topography	The topography of the USA is varied. The eastern parts of the country consist of hills and low mountains, while the central interior is dominated by the Great Plains region. By contrast, the western parts of the country include high, rugged mountain ranges, with some volcanic activity in the Pacific north-west. The landscape of Alaska features rugged mountains as well as river valleys, while the landscape of Hawaii is dominated by volcanic topography. The highest point in the country is Mount Denali in Alaska, at 6,190 metres above sea level, while the lowest point is in Death Valley, California, at 86 metres below sea level.3
Climate	The climate of the USA varies widely: arctic in Alaska, tropical in Hawaii, Mediterranean in California, arid in the south-west and temperate across much of the country.4 State-wide averages of annual temperatures range from a high of 21.5 °C in Florida to a low of -3.0 °C in Alaska. For the entire USA, excluding Hawaii and Alaska, the annual temperatures averages 11.5 °C.5
Climate Change	Annual average temperature over the continental USA has increased by 1.0 °C between 1901 and 2016. Between 2021 and 2050, annual average temperatures are expected to increase by approximately 1.4 °C relative to the 1976–2005 baseline period. Sea level rise in some parts of the USA, especially on the East and Gulf coasts, is projected to be higher than the global average. Annual trends towards earlier spring snowmelt and reduced snowpack are already affecting water resources in the western part of the country, with adverse impacts on fisheries and hydropower, and are expected to continue.6
Rain Pattern	Precipitation averages in the USA vary according to location. State-wide averages of annual precipitation range between 1,618 mm in Hawaii and 241 mm in Nevada. The annual precipitation average nationwide is 767 mm. 4,7
Hydrology	The USA has approximately 250,000 rivers and canals, stretching for millions of kilometres. The two most important rivers in the USA are the Missouri River and Mississippi River. The Missouri River is the longest at 4,088 kilometres, while the Mississippi River is the largest in terms of water volume. The Mississippi flows through 10 states, originating in the Great Lakes and emptying into the Gulf of Mexico. Most rivers in the USA have had their flows adjusted or have been dammed. The longest completely natural, undammed river in the country is the Yellowstone River at 1,114 kilometres.8

ELECTRICITY SECTOR OVERVIEW

At the end of 2020, the total installed electricity capacity in the USA was 1,212.3 GW. Thermal power, including natural gas, coal and petroleum, provided 817.9 GW (67 per cent) of the total capacity, renewable energy sources (RES) other than hydropower provided 170.9 GW (14 per cent), hydropower provided 101.9 GW (8 per cent), nuclear power provided 100.9 GW (8 per cent) and other sources provided 20.7 GW (2 per cent) (Figure 1).[9]

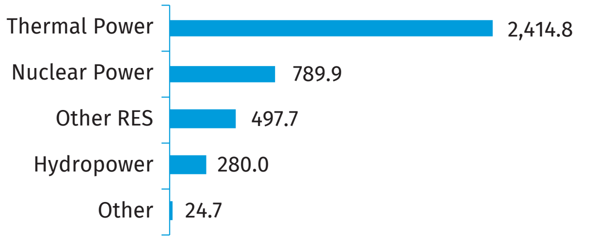
Figure 1. **Installed Electricity Capacity by Source in the United States of America in 2020 (GW)**



Source: EIA[9]

In 2020, annual utility-scale electricity generation was approximately 4,007.1 TWh. Thermal power provided 2,414.8 TWh (60 per cent) of total generation, nuclear power provided 789.9 TWh (20 per cent), RES other than hydropower provided 497.7 TWh (12 per cent), hydropower provided 280.0 TWh (7 per cent), and other sources provided 24.7 TWh (1 per cent) (Figure 2).[10]

Figure 2. **Annual Electricity Generation by Source in the United States of America in 2020 (TWh)**



Source: EIA[10]

Coal has been the largest single source of electricity supply in the USA for many years, being only recently overtaken by natural gas. Wind and solar power have also experienced significant growth, while the share of hydropower in total electricity generation has been relatively stable.[4] Total electricity consumption is forecast to increase by 0.6 per cent in 2022 and 1.4 per cent in 2023.[11] The electrification rate in the country is 100 per cent.[12]

The USA power grid connects approximately 4 million kilometres of feeder lines and over 725,000 kilometres of high-voltage transmission lines.[13] Historically, the electricity industry of the USA has comprised a mix of private and public utilities that generate and deliver electricity to customers within exclusive franchise service territories. Currently, more than 3,300 electric utilities operate across the country, with approximately 200 of them providing power to the majority of users. In the 1990s, some states and regions established competitive markets for both electricity generation and delivery. This process is often referred to as electric industry restructuring or deregulation and has resulted in new entrants to all segments of the electricity industry, including generation, transmission and delivery.[4]

Due to the historically exclusive nature of utility service territories, the electric industry has been subject to a high degree of regulation by federal, state, and local authorities. Investor-owned utilities are regulated by the states in which they operate. Municipal utilities are operated by local governments and are overseen by local elected or appointed officials. Electric cooperatives are governed by a board of directors elected from the cooperative's membership.[4]

In addition, the Federal Energy Regulatory Commission (FERC), an independent agency of the USA Government, regulates the interstate transmission of electricity. Independent System Operators (ISOs) administer the transmission grid on a regional basis, including some portions of Canada. These entities were established to provide non-discriminatory access to transmission for both electricity generators and distribution companies in competitive markets. The ISOs also perform centralized day-ahead dispatch of the generation resources in their service area to produce a least-cost production schedule for each hour of the next day, resolve gaps between generation and demand in real time and operate ancillary service markets. The USA wholesale electricity markets are displayed in Figure 3.[4]

Figure 3. **Wholesale Electric Power Markets in the United States of America**

Source: FERC[14]

Electricity tariffs in the USA are the product of a utility's generation, transmission, distribution and administrative costs as well as the return on investment in the case of investor-owned utilities. Wholesale electricity prices throughout the country trended higher throughout 2021, reflecting the increasing cost of natural gas for power generation. In Q3 2021, average electricity prices were 0.140 USD/kWh for residential consumers, 0.116 USD/kWh for commercial consumers and 0.076 USD/kWh for industrial consumers.[15]

The electricity sector faced additional challenges in 2021 due to the disruptions caused by the COVID-19 pandemic. As the economy of the USA began to emerge from its pandemic-induced recession, electricity sales rose 4 per cent through August 2021 over the previous year.[16,17]

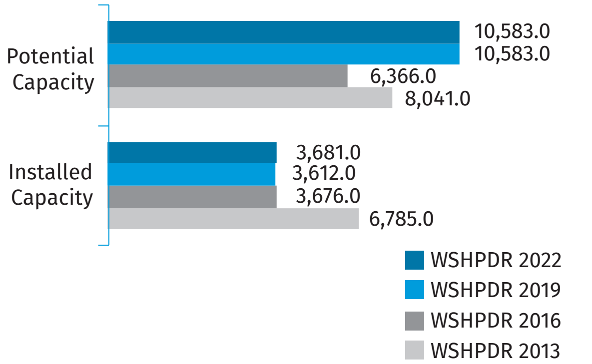
SMALL HYDROPOWER SECTOR OVERVIEW

There is no widely agreed-upon definition of small hydropower (SHP) in the USA. For the purpose of this chapter the up to 10 MW definition of SHP will be used.

In 2021, the total installed SHP capacity of the USA was 3,681 MW.[18] Total potential capacity was estimated at 10,583 MW, indicating that approximately 34 per cent of the total technical potential has been developed.[19,20,21,22,23,24] Relative to the *World Small Hydropower Development Report* (*WSHPDR*) *2019*, installed capacity increased by approximately 2 per cent, while potential capacity remained unchanged (Figure 4).

As of 2021, the existing SHP fleet of the USA consisted of 1,679 plants. The North-East and the South-West power market zones host the largest regional concentrations of SHP plants (544 and 460, respectively). During 2007–2021, the SHP fleet generated an average of 13,804 GWh per year, approximately 5 per cent of the total hydropower generation in the country.[18] A list of some recently launched SHP plants in the USA is displayed in Table 1.

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in the United States of America (MW)**



Source: *WSHPDR 2019*,[4] Johnson et al.,[18] Uria-Martinez et al.,[19] Kao,[20] Hadjerioua et al.,[21] Bureau of Reclamation,[22] Pulskamp,[23] Kao & Johnson,[24] *WSHPDR 2016*,[25] *WSHPDR 2013*[26]

Table 1. **List of Selected Existing Small Hydropower Plants in the United States of America**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Reynolds Creek	Hydaburg	5.000	Reservoir	Haida Energy, Inc	2021
Campbellas Ferry Micro-Hydro Unit Project	Idaho	0.001	Run-of-river	Campbellas Ferry Ranch, LLC	2020
Crocker	Worcester	0.145	Run-of-river	Whitman River Dam, Inc.	2020
Gordon Faber Hydroelectric Project	Washington	0.161	Run-of-river	City of Hillsboro, Oregon	2020
Wallowa Lake County Service District Hydro Station Project	Wallowa	0.020	Run-of-river	Wallowa Resources Community Solutions Inc.	2020
Pioneer Valley Hydro Site Project	Gunnison	0.006	Run-of-river	Pioneer Valley, LLC	2020
C.C. Cragin Raw Water Supply Line	Gila	0.200	Run-of-river	Town Of Payson	2019
Roemer Water Filtration Facility Hydroelectric Project	San Bernardino	0.484	Run-of-river	West Valley Water District	2019
FMC 33B Micro-hydro Project	Delta	0.005	Run-of-river	Joseph W. Yeamans	2019
Deep Creek Hydroelectric Project	San Bernardino	0.800	Run-of-river	Mojave Water Agency	2019
B24 Hydroelectric Station Project	Los Angeles	0.150	Run-of-river	San Gabriel Valley Water Company	2019
Pueblo Dam	Pueblo	7.010	N/A	Colorado Springs Utilities	2019
Timothy Lake Powerhouse	Clackamas	1.200	Run-of-river	Portland General Electric Co	2018
Calligan Creek	Kings	6.000	Run-of-river	PUD No. 1 of Snohomish County	2018
Hancock Creek	Kings	6.000	Run-of-river	PUD No. 1 of Snohomish County	2018

Source: Johnson et al.[18]

As of 2021, the USA hydropower project pipeline contained 198 projects with a combined capacity of 1,039 MW. Of these, 168 were SHP projects with a total combined capacity of 299 MW. Potential hydropower projects in the USA are classified into three categories: non-powered dams (NPDs), new stream-reach development (NSD) and conduits. The majority of planned SHP projects in the project pipeline are NPDs or projects on water conduits, with only seven projects planned for development on new stream reaches. The median capacities of planned small NPD and NSD projects are 4.8 MW and 5 MW, respectively, while the median capacity of planned conduit projects is significantly smaller (0.17 MW).[27] The south-west is the leading region by the number of planned projects but ranks last in terms of proposed capacity, as most planned SHP projects in the region are of the conduit type. Several ongoing and planned SHP projects in various parts of the country are displayed in Table 2.

Table 2. **List of Selected Planned Small Hydropower Projects in the United States of America**

Name	*Location*	*Capacity (MW)*	*Developer*	*Development stage*	*Planned launch year*
Nuyakuk River Hydro Project	Nuyakuk Falls, AK	10.00	Nushagak Cooperative	Preliminary permit	2028
Brownville Hydroelectric Project	Jefferson County, New York	9.00	Paddy Hill Holdings	Preliminary permit	2028
Greybull Valley Hydroelectric Project	Greybull, WY	4.50	Greybull Valley Irrigation District	Under construction	N/A
Loma Rica Hydroelectric Station	Nevada, CA	1.44	Nevada Irrigation District	Issued licence	N/A

Name	Location	Capacity (MW)	Developer	Development stage	Planned launch year
Wallowa Lake County Service District Hydro Station Project	Eugene, OR	0.30	Eugene Water & Electric Board	Under construction	N/A

Source: Johnson et al.[18]

Private sector development accounts for 60 per cent of proposed projects and 72 per cent of the planned capacity in the project pipeline. Most private developers are not utilities and would therefore have to negotiate a power purchase agreement (PPA) with the local utility, transfer ownership of the project to a utility, or join an independent system operator/regional transmission organization (ISO/RTO) in order to market their electricity. Any of those options add complexity to the project development cycle relative to projects implemented by utilities themselves. Investor-owned power utilities typically undertake capacity additions at existing facilities, but as of 2021 were not pursuing any new hydropower projects. Local public developers such as cooperatives, publicly-owned utilities and political subdivisions (e.g., municipalities, irrigation and water districts) pursue some hydropower development. Political subdivisions are the most active public hydropower developers in the USA, focusing primarily on adding hydropower units to conduit infrastructure they own or operate.[27]

Projects in the pending permit and issued permit stages are those undergoing feasibility evaluations. Attrition rates are high at these early stages of the development process. A project with a pending application has submitted an application for a federal permit. Projects with issued authorizations have already received their federal authorization and are more likely to proceed to construction. However, additional steps required at the issued authorization stage and prior to starting construction include obtaining additional permits at the state or local level, finalizing engineering designs, negotiating PPAs and finalizing project financing. These additional steps often pose challenges for small project developers, resulting in delays and cancellations of projects.[4]

A national assessment of the SHP capacity and generation potential realized of NPDs identified 397 dams with technical potential capacities in the 1–10 MW range. The total estimated technical potential capacity for NPDs under 10 MW is approximately 2,500 MW. Their combined annual generation potential is 4,777 GWh.[19]

A national assessment of potential NSD sites published in 2014 identified a potential technical capacity of 4,321 MW across 1,035 sites under 10 MW. The annual generation potential of these sites was estimated at 23,374 GWh.[20] Several potential NSD sites are listed in Table 3.

Table 3. **List of Selected Potential Small Hydropower Sites in the United States of America**

Name	Location	Potential capacity (MW)	Potential annual generation (GWh)	Type of site
South Fork Nooksack River	Whatcom County, WA	9.4	60.8	New
Upper Nehalem River	Portland, OR	8.0	35.3	New
Mohawk River	Albany, NY	5.8	36.4	New
Middle Fork Nooksack River	Whatcom, WA	3.3	21.4	New
East Fork Lewis River	Skamania County, WA	1.5	8.4	New

Source: Johnson et al.[18]

No nationwide resource assessment of conduit hydropower has been carried out as of 2021, although some state and federal agencies have started to compile relevant data. A 2012 study by the Bureau of Reclamation examined the energy development potential at facilities owned by the Bureau.[22] The study and a related supplement found that 191 canals had hydropower potential and that 70 of those sites could be considered economically viable for development, estimating total potential capacity at 104 MW and total potential annual generation at 365 GWh.[23]

In 2018, Oak Ridge National Laboratory developed a methodology for the analysis of the untapped hydropower potential of public water systems. A total of approximately 12 MW of potential conduit hydropower capacity was found in Oregon and 34 MW in Colorado. Corresponding annual generation was estimated at 65 GWh/year in Oregon and 202 GWh/year in Colorado.[24]

RENEWABLE ENERGY POLICY

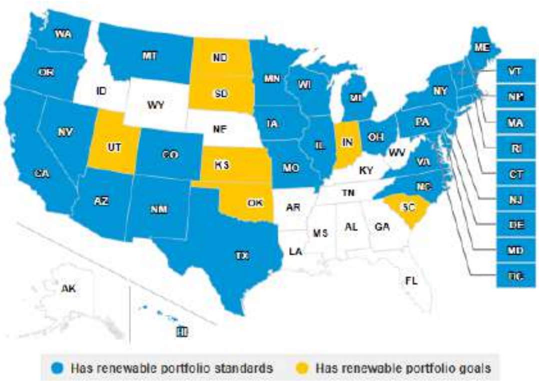
The Public Utilities Regulatory Policy Act (PURPA) of 1978 introduced competition into the USA electric power industry, particularly in the generation sector. PURPA conferred special rates and regulatory treatment on a new class of generators known as qualifying facilities (QFs). These consist of co-generation facilities and small power production facilities, with the latter defined as facilities generating 80 MW or less using a renewable energy source (i.e., hydropower, wind power, solar power, biomass, waste or geothermal power). PURPA required electric utilities to interconnect with and purchase power from QFs at the utility's "avoided cost," defined as the cost that the utility would otherwise incur in either generating the power itself or procuring power from other sources.[4,28]

With the Energy Policy Act of 2005, Congress made an important modification to PURPA, lessening PURPA's mandatory purchase obligation if FERC determines that QFs have non-discriminatory access to the market. In this context, FERC determined that an ISO generally provides a sufficiently competitive market structure to support elimination of the PURPA purchase requirement for utilities operating within the ISO. At the same time, however, FERC established that small QFs do not have non-discriminatory access to wholesale markets. Therefore, the PURPA purchase obligation for utilities remains in force for small QFs, making it possible for SHP generators to secure utility PPAs. In May 2018, FERC announced that it would launch a review of PURPA to examine issues involved in its implementation and ways to address them.[4,28] In July 2020, FERC updated PURPA regulations with Order 872, which could lead to reductions in the number of hydropower projects eligible to receive avoided cost rates and increase energy price risk for developers and owners of hydropower facilities under new PURPA contracts.[27]

The federal Government also provides tax incentives to spur RES development. Tax credits for the production of and investment in hydropower expired at the end of 2016, but were available for other RES facilities which had commenced construction prior to 31 December 2021. SHP has also been eligible for federal accelerated depreciation tax treatment and some states offer tax incentives and exemptions.[4]

Individual states in the USA have adopted policies to encourage RES development. The most prominent of these policies has been the adoption of a renewable portfolio standard (RPS). An RPS is a market-based policy that requires electric utilities and other retail electricity suppliers to supply a minimum percentage of their electricity sales from eligible RES. As of September 2020, 38 states and the District of Columbia had established an RPS or renewable portfolio goal, with 12 states and the District of Colombia setting a 100 per cent clean electricity target by 2050 or earlier (Figure 5).[29,30,31] RPS-related policy revisions adopted in recent years have additionally included increased RPS targets in many states.

Figure 5. **Renewable Portfolio Standards Status in the United States of America as of September 2020**



Source: DSIRE[30]

Common hydropower restrictions for RPS eligibility include those based on capacity, type and environmental sustainability criteria and often limit RPS eligibility to SHP only. One environmental standard is the Low Impact Hydropower Institute certification standard, used for RPS eligibility in a variety of states.[32] At the same time, many RPS policies have vintage requirements for new development, which can disqualify hydropower production from RPS eligibility.[4]

Feed-in tariffs (FITs) have been adopted by some states and utilities to incentivize electricity procurement from smaller renewable energy generators. An SHP system installed adjacent to a local electricity load can typically take advantage of net energy metering (NEM). Most states in the USA have some form of NEM requirement, providing a potent economic incentive for distributed renewable energy generation, including SHP.[4,31]

Renewable energy development in the USA is poised to accelerate in 2022 due to increasing concerns regarding climate change and widespread support for environmental, sustainability and governance (ESG) considerations. Measures adopted by the Biden administration to fully decarbonize the economy of the country, including the 2021 Infrastructure Investment and Jobs Act (IIJA), are helping spur activity in the renewable sector that will likely drive further growth.[33].

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Developers of SHP projects need to follow different approval processes depending on ownership, project type and other project attributes. Most projects require a FERC licence or an exemption from licensing. Although the exemption process is typically shorter than the licensing process, both processes usually require multiple years to complete. Seeking authorization for development of hydropower at U.S. Army Corps of Engineers (USACE)-owned dams involves obtaining a Section 408 approval from USACE in addition to a FERC licence. The two processes are usually implemented sequentially, with most of the work needed to obtain a USACE approval taking place after a FERC licence is issued. Securing federal authorization for development of hydropower at Bureau of Reclamation-owned dams does not typically involve FERC, but rather a Lease of Power Privilege process.[4,34]

The Hydropower Regulatory Efficiency Act of 2013 introduced a quicker, easier pathway to regulatory approval for the subset of projects involving the addition of hydropower to non-federal conduits (typically, existing pipelines and canals) with capacities of less than 5 MW. In the case of such projects, the developer must notify FERC of the intention to construct a hydropower facility. The project will typically complete the federal approval process and receive the “qualifying conduit” status within 60 days unless FERC or the public contest the project’s ability to meet the eligibility criteria.[4]

In October of 2018, Congress passed the America’s Water Infrastructure Act, which included provisions to help streamline federal regulatory approval processes for hydropower.

The bill shortens the FERC process for qualifying conduit determination required by the 2013 Hydropower Regulatory Efficiency Act from 60 to 45 days, reducing the length of the entire licensing process to 2 years from application to final decision, and replaces the 5 MW cap on qualifying conduit hydropower with a 40 MW cap. The bill also requires FERC to establish an expedited licensing process for NPD projects that will shorten the FERC decision timeframe for licence applications to two years or less. The bill also requires FERC, USACE and the U.S. Department of the Interior to develop a list of existing federal NPDs that have the greatest potential for hydropower development.[4]

COST OF SMALL HYDROPOWER DEVELOPMENT

The cost of SHP development in the USA has been examined in a 2015 report, which arrived at an average cost of 4,236 USD/kW for NPDs, 4,774 USD/kW for facilities built in canals or conduits and 5,320 USD/kW for NSD projects. Capacity-weighted averages are very close to the raw means for NPDs (4,515 USD/kW) and NSDs (5,558 USD/kW) but significantly lower for canal and conduit projects (3,213 USD/kW). This divergence indicates that canal and conduit projects display stronger economies of scale than the other project types.[27,35]

Ninety-one percent of hydropower plants built since 1980 and 97 per cent of those built since 2005 have had capacities below the 10 MW threshold. The small average size of new projects in the USA helps explain the higher average capital cost per kilowatt relative to global averages.[27,36]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Financial instruments used for hydropower project finance in the USA typically come from equity finance (public or private), debt finance, commercial lending and grants.[37]

The Office of Energy Efficiency and Renewable Energy's Water Power Technologies Office (WPTO) offers annual funding under the Hydroelectric Production Incentive Programme under Section 242 of the Energy Policy Act of 2005. A total of USD 7 million was to be available in 2022 for qualifying facilities. The programme provides funding for new hydropower projects on existing dams and other water infrastructure. The maximum payment per facility has been increased to USD 1 million per year, from the 750,000 USD/year limit in the previous round. Additionally, recent legislation amended the length of the eligibility window for applicants, with hydropower facilities placed in operation between 1 October 2005 and 30 September 2027 now being eligible for consideration of incentive payments. Applicants may receive up to 0.018 USD/kWh for hydropower generated during the calendar year 2020 incentive period, with a maximum of USD 1 million depending on the total kWh of eligible power generation.[38]

Some states have created programmes and policies specifically targeting SHP development. For example, in California some types of SHP projects are eligible for incentive funding through the state's Self-Generation Incentive Programme. Colorado provides USD 15,000 feasibility grants for eligible entities, as well as low-interest (2 per cent), 30-year loans that can fund project construction. Oregon provides financial assistance to SHP developers through the Energy Trust of Oregon.[4,39]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The most important climate change impacts on hydropower generation in the USA are likely to be early snowmelt and change of runoff seasonality, and reservoir storage will gain increasing importance as a buffer against runoff variability. Climate change models predict an overall increase in runoff (up to 26 per cent) and in hydropower generation (up to 20 per cent) during 2031-2050, relative to the 1966-2005 baseline period. For regions with smaller storage capacities, variability of future hydropower generation will more closely follow anticipated changes in runoff. While current reservoir capacities are considered sufficient to absorb at least a part of the runoff, the issue of ageing infrastructure, competition for water use, and environmental services are likely to put additional pressure on the ability of the existing reservoirs to provide sufficient storage for stable hydropower generation on an annual basis.[40,41]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The barriers to the development of SHP in the USA include the following:

- Regulatory approval challenges due to uncertain federal regulatory processes that have made it difficult for public- and private-sector investors to obtain long-term, low-cost financing to support project development;
- Competition from other sources of power generation and lack of adequate compensation for ancillary services;
- High operation and management costs for SHP plants;
- Lack of comprehensive information regarding potential SHP sites on conduits such as water supply pipelines, which represent perhaps the most economically-feasible type of new hydropower;
- Risk aversion regarding new technology on the part of dam and conduit owners as well as technical inspectors and a lack of understanding of SHP technologies in particular, in part due to a lack of extensive operational track records;
- Lack of standardized technology, as almost every hydropower project is custom-engineered and site-specific;
- Uncertainty in the cost, timing and technical require-

ments of grid interconnection;
- State and local regulatory policies, including regulatory issues associated with water quality certifications and other state and local environmental requirements.

Factors enabling SHP development in the country include:
- Recent advancement in standardized powertrain components, biologically-based equipment design and evaluation, additive manufacturing, modular civil structure design and alternative closed-loop pumped storage hydropower (PSH) systems can reduce the cost of SHP equipment, as well as improve performance and environmental stewardship;
- Increased attention to frameworks for assessing climate change impacts will improve the ability of hydropower projects to operate under resultant increases in water resource variability;
- Access to low-cost capital due to historical low interest rates is likely to encourage financing of SHP projects;
- An expedited licensing process introduced by the America's Water Infrastructure Act of 2018 will reduce uncertainties and risks related to project financing and implementation.

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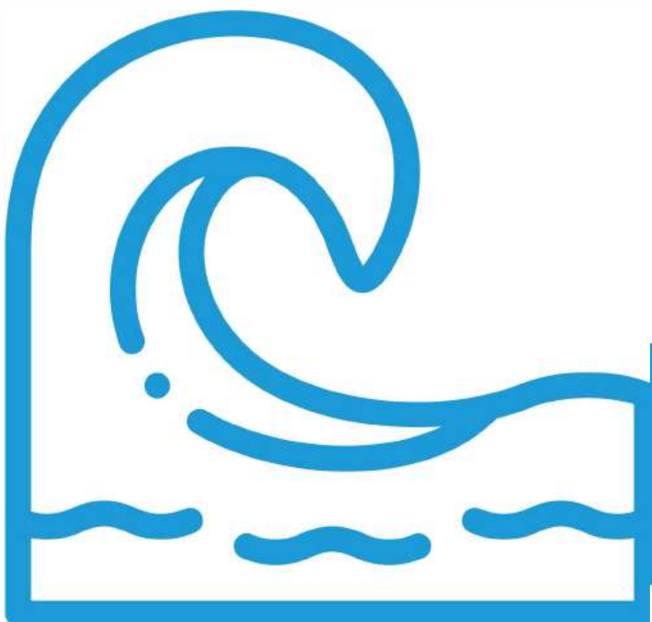


3. Asia

3.1. Central Asia

Danila Podobed, International Center on Small Hydro Power (ICSHP)

Countries: Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan, Uzbekistan

INTRODUCTION TO THE REGION

The electricity sectors of the countries in Central Asia share many common features due to their common history as constituent republics of the Soviet Union. Among these features is a high degree of regional interconnectivity of the national power grids through the infrastructure of the Central Asian Power System (CAPS), originally built during the Soviet period. However, in recent decades, participation in power sharing through CAPS has been suspended by Turkmenistan and partially by Uzbekistan. Another common feature is the advanced age of much of the power grid and generating capacities across the region due to a lack of adequate investment in the post-Soviet period, coupled with rising electricity demand outpacing grid capacities. While electricity access remains at or near 100 per cent across the region, interconnectivity and aging infrastructure have led to occasional cross-border power shortages and blackouts.

The role of hydropower in Central Asia differs from country to country. Kyrgyzstan and Tajikistan both have significant hydropower resources and their electricity sectors are dominated by generation from hydropower, providing Kyrgyzstan with over three quarters of the country's installed capacity and over 90 per cent of electricity generation, and Tajikistan with slightly under 90 per cent of installed capacity and over 90 per cent of generation. However, transboundary water disputes between these two countries have led to intermittent conflict followed by periods of negotiation over water use rights. In Kazakhstan and Uzbekistan, most electricity generation is from thermal power due to abundant reserves of fossil fuels, with hydropower playing a significant but supplementary role. Some hydropower capacity also exists in Turkmenistan, but its share of the country's energy mix is negligible and the country's electricity sector depends almost entirely on thermal power.

An overview of the electricity sectors of the countries in the Central Asia region is provided in Table 1.

Table 1. **Overview of Central Asia**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Kazakhstan	19	100	100	22,936	108,086	2,666	9,546
Kyrgyzstan	7	100	100	3,946	15,293	3,084	13,919
Tajikistan	10	100	100	6,124	20,676	5,406	19,169
Turkmenistan	6	N/A	N/A	6,511	24,000	1	N/A
Uzbekistan	35	100	100	15,949	66,407	1,908	5,019
Total	-	-	-	**55,466**	-	**13,065**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in Central Asia is largely inherited from the Soviet period and encompasses hydropower plants with a capacity of up to 30 MW in the case of Kyrgyzstan, Tajikistan and Uzbekistan. Kazakhstan follows the up to 35 MW definition, however, the up to 30 MW definition is also used occasionally, alongside the up to 10 MW definition used in renewable energy auctions. There is no definition of SHP in Turkmenistan.

A comparison of installed and potential capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Central Asia (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (<10 MW)*	*Potential capacity (<10 MW)*
Kazakhstan	Up to 35 MW	255.0	2,354.4	118.0	1,380.9
Kyrgyzstan	Up to 30 MW	53.8	N/A	53.8	311.8
Tajikistan	Up to 30 MW	142.1	N/A	54.7	30,000.0
Turkmenistan	N/A	N/A	N/A	1.2	1,300.0
Uzbekistan	Up to 30 MW	303.6	1,392.0	87.8	87.8*
Total	-	-	-	**315.5**	**33,080.5**

Source: *WSHPDR 2022*

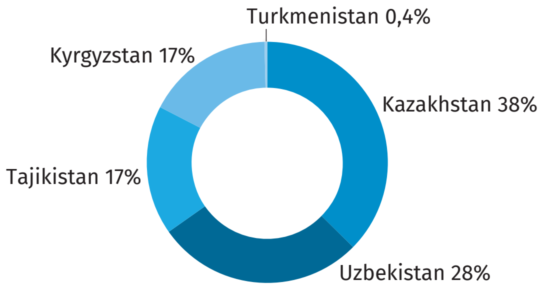
Note: *Based on installed capacity.

The total installed capacity of SHP up to 10 MW in Central Asia is 315.5 MW, while the potential capacity is estimated at 33,080.5 MW, with Tajikistan accounting for over 90 per cent of the total estimated potential. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP up to 10 MW has increased by nearly 19 per cent, while the estimate of potential capacity has decreased by nearly 4 per cent, mainly due to a re-evaluation of data on the potential SHP capacity of Kazakhstan.

The SHP sector is well-developed in all countries in Central Asia with the exception of Turkmenistan. The largest installed SHP capacities, according to the local definition, are in Uzbekistan and Kazakhstan, where they form a significant share of total installed hydropower capacity. Conversely, the largest assessed SHP potential in the region is found in Tajikistan, a country defined by mountainous topography and abundant hydropower resources. SHP has a long history in Central Asia, with the first SHP plants constructed just prior to the First World War. In recent years, SHP in the region has seen active development, with private companies playing an increasingly prominent role.

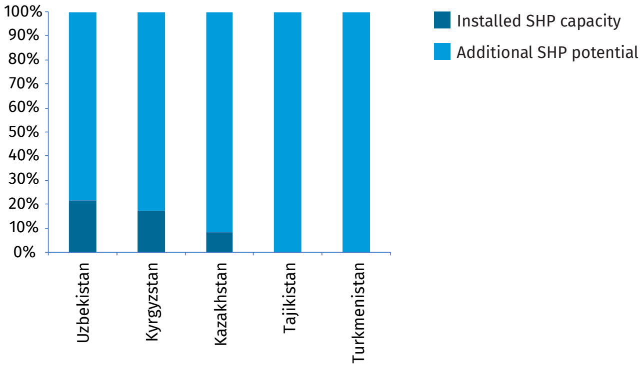
The national share of regional installed capacity for SHP up to 10 MW by country is displayed in Figure 1, while the share of total national SHP potential utilized by countries in the Central Asia region is displayed in Figure 2.

Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Central Asia (%)**



Source: *WSHPDR 2022*[1]

Figure 2. **Utilized Small Hydropower Potential by Country in Central Asia (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP up to 10 MW except in the case of Uzbekistan, where the local definition of SHP is used due to lack of other data.

The installed SHP capacity of **Uzbekistan** is estimated at 303.6 MW for SHP up to 30 MW and at 87.8 MW for SHP up to 10 MW. Potential capacity for SHP up to 30 MW is estimated at 1,392 MW, indicating that approximately 22 per cent has been developed. No estimate of potential capacity for SHP up to 10 MW is available. During the mid-20th century, there were over 250 operational SHP plants in the country, but most of these are no longer in use. In recent years, the Government has actively pursued SHP development, launching an ambitious programme of SHP construction and refurbishment in 2017. The programme includes specific plans to add an additional 35 new SHP plants with a total installed capacity of 349 MW and to increase the installed capacity of 23 existing plants to 251.4 MW by 2030. Several new SHP plants were commissioned and one plant was refurbished in 2019.

The installed SHP capacity of **Kazakhstan** for SHP plants up to 35 MW was 255 MW as of mid-2021, while potential capacity is estimated at 2,354.4 MW, indicating that approximately 11 per cent has been developed so far. For SHP up to 10 MW, installed and potential capacity is 118 MW and 1,380.9 MW, respectively, indicating that approximately 9 per cent has been developed. As in Uzbekistan, a large number of SHP plants were constructed in Kazakhstan during the Soviet period and many have since fallen into disuse or require extensive rehabilitation. The country aims to add up to 1,500 MW of SHP capacity by 2030.

In **Kyrgyzstan**, there were a total of 18 SHP up to 10 MW plants operating as of 2020, with an installed capacity of 53.8 MW. Although the national definition of SHP includes plants up to 30 MW, in practice, there are no hydropower plants with a capacity of between 10 MW and 30 MW in the country. Potential capacity for SHP up to 10 MW is estimated at 311.8 MW, indicating that 17 per cent of the known potential has been developed. The construction of new SHP plants in Kyrgyzstan in recent years has been carried out solely by private sector developers. A number of government initiatives targeted the addition of 41 new SHP plants with a total capacity of 178 MW by 2025, but the pace of development has lagged due to issues with funding, project delays, as well as institutional, legal and technical obstacles.

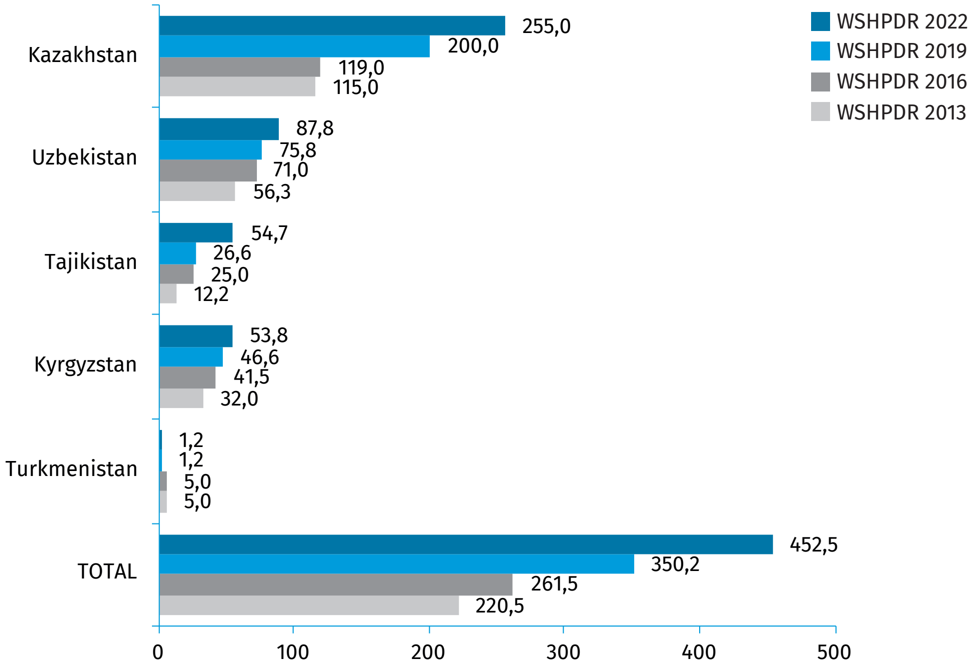
Although the definition of SHP in **Tajikistan** includes plants up to 30 MW, in practice, the SHP fleet of the country is largely composed of hundreds of very small plants with capacities ranging from several hundred kilowatts to several megawatts.

The total installed capacity of SHP up to 30 MW in Tajikistan as of 2021 was 142.1 MW, of which 44.8 MW was operated by the private-public company Pamir Energy to supply electricity to the semi-isolated Gorno-Badakhshan Autonomous Region, powered solely by SHP. The installed capacity of SHP up to 10 MW in 2021 was 54.7 MW, while the potential SHP capacity up to 10 MW is estimated at 30,000 MW, suggesting that only a small fraction of this potential has been developed so far. Extensive plans for the construction of SHP in Tajikistan were drawn up during the Soviet period but only partially realized. The construction of SHP plants picked up again after 1995, with 155 plants constructed between 1995 and 2021 with a cumulative capacity of 12.5 MW.

The only operational SHP plant of **Turkmenistan**, the Hindigush hydropower plant on the Murgab River, was built in 1913 with a capacity of 1.2 MW and remains in use to this day. The country's SHP potential is estimated at 1,300 MW, indicating that less than 1 per cent has been developed. Plans for the refurbishment of several previously operational SHP plants as well as the construction of new plants have been proposed since 2011 but have not been realized.

Changes in the installed SHP capacities of countries in the Central Asia region compared to the previous editions of the *World Small Hydropower Development Report (WSHPDR)* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

Note: For SHP up to 10 MW except in the case of Kazakhstan, where the local definition of SHP is used for purpose of comparison with previous years.

Climate Change and Small Hydropower

The glacierized areas in this region show increased summer and winter runoff. Meanwhile, the areas with a lower fraction of glaciers present an increased interannual variation in streamflow. The magnitude of the projected runoff varies significantly across climate change scenarios. For example, Kazakhstan estimates that precipitation could increase up to 10 per cent by 2050. Kyrgyzstan forecasts that climate change will lead to a decrease in hydropower potential, even though SHP can be a great strategy to mitigate energy shortages in remote areas in the short term.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers to SHP development in **Kazakhstan** include an aging power grid unable to accommodate significant additional SHP development, problems with financing and the cheap cost of generation from fossil fuels, in addition to a lack of up-to-date studies on SHP potential in the country. At the same time, the regulatory framework is strongly supportive of SHP development and the Government has outlined specific plans with clear targets for the construction of significant additional SHP capacities by 2030. Incentives for SHP in Kazakhstan include tax, customs and connection fee waivers, guaranteed purchase prices and periods, as well as in-kind aid.

Uzbekistan shares several barriers to SHP development with Kazakhstan, including an aging power infrastructure, low cost of electricity from fossil fuels and lack of up-to-date studies of SHP potential. In addition, there is a lack of clear government incentives and private financing for SHP projects, although several new policies articulating government support for SHP development have been adopted in recent years. The main enablers for SHP development in the country include the large number of decommissioned or abandoned SHP plants that may be refurbished, as well as the significant untapped SHP potential on both natural watercourses and manmade canals.

The development of SHP in **Kyrgyzstan** is hindered by many obstacles, including a lack of government financing, institutional and legal barriers as well as political and economic instability. In addition, there are material factors impeding SHP construction in Kyrgyzstan such as a lack of technical capacities and environmental hazards including flooding, bank erosion, potential seismic risk and severe winter weather. Enabling factors include a large untapped SHP potential assessed across several studies, existing framework of preferential tariffs for SHP projects and the high cost of electricity generation from fossil fuels in the country, which has increased demand for alternative energy sources.

In **Tajikistan**, barriers to SHP development include the fragmentary nature of SHP planning and construction, which has resulted in a proliferation of mini- and micro-hydropower plants with higher per-kilowatt costs than those of larger plants, as well as the low electricity tariff caps mandated by the Government, which make it difficult to recoup the cost of new SHP construction. Despite this, financing for SHP in Tajikistan is generally more readily available than for larger hydropower projects, and the country's massive SHP potential suggests opportunities for new projects are available.

While abundant SHP potential exists in **Turkmenistan**, the main barrier to its development has been the country's access to cheap domestically-sourced fossil fuels. However, renewable energy has been receiving increasing attention in the country in recent years, leading to the adoption of several national renewable energy policies as well as bilateral agreements on cooperation in the renewable energy sector. The ongoing construction of the Altyn-Asyr water conveyance network presents an additional opportunity for the realization of SHP projects with a reduced environmental impact.

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Kazakhstan

Galina Livingstone, Livingstone Environmental Ltd.

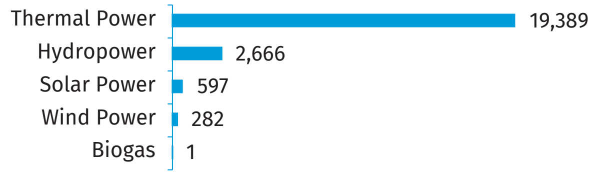
KEY FACTS

Population	18,631,779 (2020)[1]
Area	2,724,900 km^2 [2]
Topography	Most of the country lies between 200 and 300 metres above sea level. Just over 70 per cent of the country is desert, semi-desert or steppe. A vast flat steppe extends from the Volga River in the west to the Altai Mountains in the east and from the plains of Western Siberia in the north to the oases and deserts of Central Asia in the south. Kazakhstan is mountainous along its far eastern and south-eastern borders, where much of the forested Altai and Tian Shan ranges remain snow-capped throughout the year and with many elevated peaks exceeding 6,500 metres. The highest point is Mount Khan Tengri at 7,010 metres above sea level.[3]
Climate	The climate is extreme continental (excluding the south) with cold winters and hot summers. The average temperature in January ranges from -19°C in the north to -4°C in the south and in July from 19 °C in the north to 26 °C in the south. The lowest and the highest temperature records are extreme (-57 °C and +49 °C). Approximately 90 per cent of the country lies in the arid and semiarid zones. There are frequent high winds and dust storms due to the clashes between different air masses, especially in spring.[4,5]
Climate Change	The average annual air temperature in Kazakhstan is gradually increasing at the rate of 0.31 °C every 10 years, as observed between 1936 and 2005. A 1.4 °C increase in mean annual temperature is expected by 2030. The country is facing significant impacts resulting from climate change, including increased aridity, challenges in water management, extreme weather events and the degradation of glaciers.[4,5]
Rain Pattern	The rainiest part of the country lies in the north (roughly above the 50th parallel), where the average annual precipitation exceeds 300 mm. Precipitation drops to approximately 150–200 mm in the centre and south and to as low as 100 mm around the Aral Sea. Average annual precipitation is higher in the south-eastern mountainous area, e.g., the average annual precipitation in Almaty amounts to 585 mm. Snow is frequent in winter, but it is often light.[6]
Hydrology	Four major hydrological regions can be distinguished in Kazakhstan: the Ob River basin draining to the Arctic Ocean, the Caspian Sea basin, the Aral Sea basin and internal lakes, depressions or deserts. Kazakhstan has 8,500 small and large rivers and approximately 48,000 lakes. The main water basins in the country are the Chu-Talas, Aral-Syr Darya, Balkhash-Alacol, Ural-Caspian, Nura-Sarysu, Tobol-Turgai, Irtysh and Ishim basins. The distribution of surface water resources within the country is extremely uneven and is marked by significant perennial and seasonal dynamics. Central Kazakhstan has only 3 per cent of the country's total water resources. The western and south-western regions (Atyrau, Kyzylorda and Mangystau regions) are highly water-deficient. The Balkhash-Alakol and Irtysh River basins in the east and north-east account for almost 75 per cent of surface water resources generated within the country. Approximately 90 per cent of the runoff occurs in spring, exceeding reservoir storage capacity.[6]

ELECTRICITY SECTOR OVERVIEW

As of 1 January 2020, there were 179 power plants operating in Kazakhstan with a total installed capacity of 22,936 MW, including 19,389 MW (85 per cent) provided by thermal power plants, 2,666 MW (12 per cent) by hydropower plants, 597 MW (3 per cent) by solar power, 282 MW (1 per cent) by wind power and 1 MW (less than 1 per cent) by a biogas plant (Figure 1). Available capacity at the beginning of 2020 was somewhat lower than installed capacity, at 19,329 MW, while the maximum daily capacity load over the course of 2019 was 15,182 MW.[7,8,9]

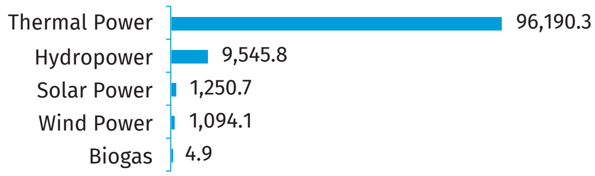
Figure 1. **Installed Electricity Capacity by Source in Kazakhstan in 2020 (MW)**



Source: Samruk Energy[7]

Total electricity generation in 2020 equalled 108,085.8 GWh, of which 96,190.3 GWh (89 per cent) was provided by thermal power, 9,545.8 GWh (9 per cent) by hydropower, 1,250.7 GWh by solar power (1 per cent), 1094.1 GWh (1 per cent) by wind power and 4.9 GWh (less than 1 per cent) by biogas (Figure 2).[7,10] Electricity imports in 2020 amounted to 1,555.4 GWh, while exports reached 1,968.7 GWh.[10]

Figure 2. **Annual Electricity Generation by Source in Kazakhstan in 2020 (GWh)**



Source: Samruk Energy[7,10]

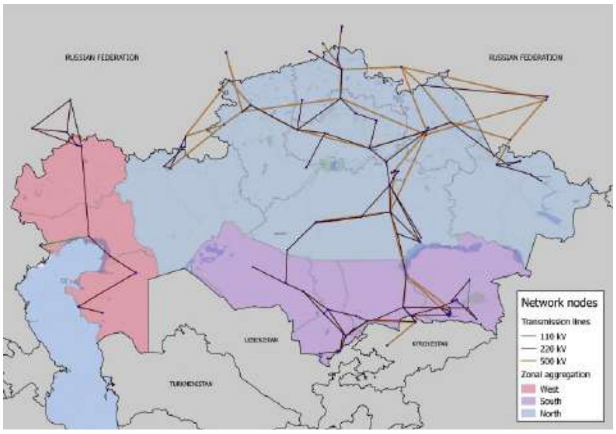
Access to electricity in Kazakhstan is 100 per cent.[11] Consumption of electricity in 2020 amounted to 107,344.8 GWh.[7,10] Both consumption and generation of electricity have been gradually increasing over the last decade. On average, the annual increase in electricity production between 2015 and 2020 was 2 per cent, while the increase in consumption was 3 per cent. Should this trend continue, the country would experience a generation deficit by 2027, provided no additional generation capacities are commissioned. Economic development of the country is expected to cause further growth in consumption, increasing at over 2 per cent per year until 2030 and reaching 136 TWh, and by over 1 per cent per year between 2030 and 2050 to reach 172 TWh.[12,13] The power sector of Kazakhstan is additionally hobbled by aging Soviet-era assets: 65 per cent of the equipment is over 20 years old and 31 per cent over 30 years old, with at least 60 per cent of equipment requiring modernization.[14] Consequently, the number of technical failures and interruptions has been on the rise, increasing from 4,010 in 2019 to 4,458 in 2020.[15]

While the Government of Kazakhstan is implementing plans for the modernization of the power sector, major state-financed programmes are lacking and the attraction of investments in the power sector is carried out within the framework of the electricity market. Kazakhstan has been particularly successful in attracting investments in the hydropower sector, totalling USD 2.78 billion in 2020 (nearly 2 per cent of the Gross Domestic Product).[16]

The structure of the electric power sector of Kazakhstan is composed of several economically independent entities, including electricity producers, primarily privately-owned; the national electricity grid operator Kazakhstan Electricity Grid Operating Company (KEGOC), operating the backbone grids of 220/500/1150 kV; and regional electricity companies (RECs), both private and state-owned, operating grids of 110 kV and below.[9] The National Welfare Fund of Kazakhstan, Samruk-Kazyna JSC, is the main shareholder of KEGOC with 90 per cent state ownership. It also holds a 100 per cent stake in Samruk-Energy JSC, which operates most of major power plants in the country. In terms of operational dispatch management in the United Energy System of the Republic of Kazakhstan (UES RK), nine regional dispatch centres are in direct operational subordination to the KEGOC's Unified Dispatching Office.[17,18,19]

Geographically, the country is serviced by three electric infrastructure zones — the North, South and West (Figure 3). The North and South zones are integrated as the UES RK, a set of power plants, power lines and substations operated by KEGOC provide energy supply to consumers in the two zones. In its turn, the West zone is isolated from the UES RK due to its geographical remoteness and sparse population, although there are plans to integrate the West zone with the UES RK in the future.[17,20]

Figure 3. **Electric Power Infrastructure Zones in Kazakhstan**



Source: Assembayeva et al.[21]

Each of the three electric power infrastructure zones of Kazakhstan is connected to power grids in the neighbouring ex-Soviet countries: the North and West zones are connected to the United Energy System (UES) of the Russian Federation, while the South zone is integrated with the Central Asian UES.[20,22] In addition, Kazakhstan, as a member of the Eurasian Economic Union (EAEU), is working on the establishment of a common electricity market in the EAEU by integrating the national electricity markets of Armenia, Belarus, Kazakhstan, Kyrgyzstan and Russia on the basis of parallel electric power systems.[23]

The North zone generates more than 77 per cent of all electricity in the country and accounts for approximately two thirds of national electricity consumption, while containing only 41 per cent of the country's population, due to the concentration of industrial consumers in the region. The South zone accounts for 21 per cent of consumption, but it is power-deficient and covers power shortages by supplies from the North zone and the Central Asian UES. The West zone is also characterized by power deficits and relies on electricity imports from Russia.[24]

Despite the overall surplus of electric capacity in the country, there is a shortage of flexible capacity capable of quickly compensating the power deficit in the UES RK during the peak loads due to a high degree of reliance on coal-fired power plants. Opportunities for the construction of new large-scale hydropower plants for the purpose of providing this capacity are limited in the country and current plans to develop flexible capacity focus mostly on the construction of additional gas-fired power plants by 2025.[25,26]

According to the Law on the Electric Power Industry of the Republic of Kazakhstan, electric power in the country is traded at the wholesale and retail markets.[27] From 1 January 2019, a new wholesale electric power market was launched in Kazakhstan, which divided the electricity market into two separate segments: the capacity supply segment and the electricity supply segment. Within the framework of the wholesale electricity market, the wholesale electricity tariff is divided into two parts:

- A set capacity tariff for maintaining readiness of the generating capacity;
- A variable electricity tariff that ensures return on the cost of electricity production.

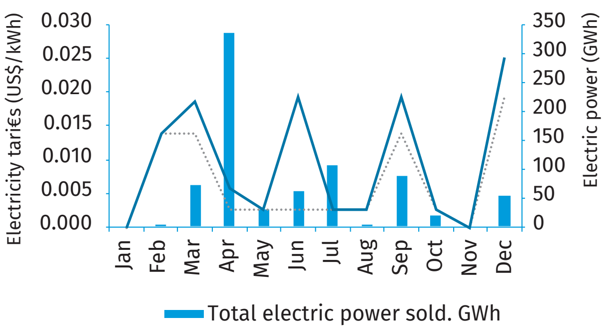
The maximum wholesale market tariffs for individual electric energy generating companies are set by the Ministry of Energy of the Republic of Kazakhstan and regulated by the Agency for Protection and Development of Competition. The tariffs are established in accordance with national legislation and capped with consideration of the socio-economic conditions in the country.

The capacity supply segment was added in 2019 to the already existing electricity supply market to encourage investments in the renovation of old power facilities and the construction of new ones. All generating companies in Kazakhstan must maintain a specific generating capacity and all consumers participating in the wholesale electric power market have an obligation to pay for the availability of the specific generating capacity.

In 2020–2021, the maximum monthly capacity tariff was fixed at 590,000 KZT/MW (1,437.7 USD/MW) (excluding value-added tax (VAT)). Although the Law on the Electric Power Industry stipulates that the approved wholesale tariffs should be fixed for seven years, the Ministry of Energy can allow raising them earlier at the request of electricity generating companies in case of a proven increase in their power generation expenditures (e.g., associated with modernization of their assets).[27,28,29] According to the Law, the Financial Settlement Centre of Renewable Energy LLP (FSC) of KEGOC concludes contracts with power producers for maintaining availability of the capacity supply. The fees for the capacity supply services are included in the general fees paid by the consumers; they are collected by FSC, and consequently paid to the power plants. Thus, the costs of building new power plants and the expansion and modernization of existing power plants are distributed evenly among all consumers.[30]

For the electricity supply segment of the wholesale market, power producers independently establish their electricity tariffs, within the maximum tariff cap approved by the Ministry of Energy.[27] Wholesale electricity tariffs vary throughout the year. The highest tariff per kWh in 2020 was in December at 10.39 KZT/kWh (0.03 USD/kWh) (Figure 4).[28]

Figure 4. **Dynamics of the Wholesale Electric Energy Market in Kazakhstan in 2020**



Source: Market Council of the Kazakhstan Electric Power Association[28]

In the retail electric power market, electricity supply companies purchase electricity, either directly from power producers or at centralized auctions carried out on the wholesale market, and then sell it to the retail consumers. The retail tariffs for electricity in Kazakhstan are very low in comparison with many other countries. For example, the maximum electricity tariff per 100 kWh for households in Kazakhstan in 2020 was fixed at approximately 0.03 USD, while the world average for the same year was 13.7 USD.[28,29,31] However, electricity tariffs are gradually rising, having increased by nearly 7 per cent in 2020 relative to the previous year.[28,29]

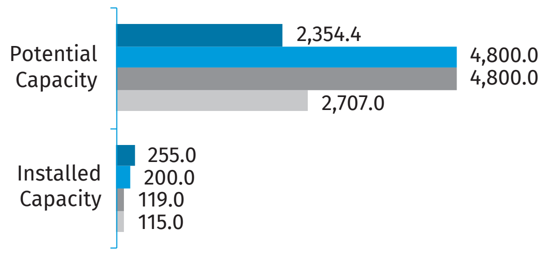
SMALL HYDROPOWER SECTOR OVERVIEW

Hydropower is a major source of electricity production in Kazakhstan. The country's hydropower resources are concentrated in the Eastern, Southern and South-Eastern regions.[32] The technical potential of hydropower in the country is approximately 62 GWh per year, while the economically feasible potential is estimated at 25–27 GWh per year.[33,34] These figures contrast with actual hydropower generation from available capacities, which totalled approximately 9.5 TWh in 2020 (Figure 2).

The definition of small hydropower (SHP) in Kazakhstan, established by the 2009 Law on Supporting the Use of Renewable Energy Sources (RES) for identifying hydropower plants eligible for incentives, applies to hydropower plants of up to 35 MW installed capacity and without reservoirs.[35] Otherwise, there is no formal regulatory definition of SHP in the country. The up to 30 MW definition, inherited from regulations in force during the Soviet period, is used occasionally, while state-supported auctions for RES use the up to 10 MW definition. Consequently, the upper threshold for SHP in Kazakhstan varies across publications. In the current chapter, both the 10 MW and 35 MW definitions are considered.

As of mid-2021, the total installed capacity of SHP in Kazakhstan was 255 MW for plants of up to 35 MW installed capacity and approximately 118 MW for SHP up to 10 MW.[36] Potential capacity for SHP up to 35 MW has been estimated at 4,800 MW by the United Nations Development Programme (UNDP).[23] However, previous detailed studies of regional hydropower potential suggest a more modest figure of 2,354.4 MW for SHP up to 30 MW and 1,380.9 MW for SHP up to 10 MW (Table 2).[37] The 2,354.4 MW estimate is taken as more accurate and representative of potential capacity for SHP up to 35 MW, as no detailed studies of potential capacity for SHP between 30 MW and 35 MW have taken place and in practice, very little such potential is believed to actually exit in the country.[12] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP up to 35 MW has increased by nearly 28 per cent due to the commissioning of several SHP plants in recent years, while the estimated potential capacity has decreased by approximately 51 per cent due to a reassessment of available data from previous studies (Figure 5).[38]

Figure 5. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Kazakhstan (MW)**



Source: Ministry of Energy,[36] UNDP,[37] *WSHPDR 2019*,[38] *WSHPDR 2013*,[39] *WSHPDR 2016*[40]

Note: Data for SHP up to 35 MW.

Many SHP plants were constructed and operated in Kazakhstan during the Soviet period, but most have since been abandoned and are too dilapidated to allow renovation. However, there are notable exceptions, such as SHP plants No.6, No.7 and No.8 near Almaty, constructed in the 1940s for powering heavy industry evacuated to Kazakhstan from other parts of the Soviet Union during World War II. These plants, originally equipped with Leffel turbines and 2.5 MW General Electric generators supplied to the Soviet Union by the United States during the war through the Lend-Lease Programme, are still in operation today, although in a state requiring major renovations.[41] More recently, individual SHP plants and cascades of plants have been constructed on the Issyk, Karatal, Kora, Lepsy and Keles Rivers, among others. Many of the older SHP plants require extensive renovation. A partial list of existing SHP plants in Kazakhstan in displayed in Table 1.

Table 1. **List of Selected Existing Small Hydropower Plants in Kazakhstan**

Name	*Location (River)*	*Capacity (MW)*	*Head (m)*	*Type of plant*	*Operator*	*Launch year*
Turgusun-1	Turgusun	24.9	N/A	Run-of-river	Turgusun-1, LLP	2021
Chazhinskaya-2	Chazha	25.8	N/A	Run-of-river	ASPMK-519, LLP	2021
Darkhan	Keles	4.2	15.0	Run-of-river	SmartReEnergy, LLC	2020
Issyk-1	Issyk	5.0	144.5	Run-of-river	HydroPower, LLP	2019
Ulbinskaya	Tikhaya	27.6	155.0	Run-of-river	Kompaniya LK GES, LLP	1937/ 2019
Korinskaya-2	Kora	2.1	83.7	Run-of-river	Korinskaya GES, LLP	2017
Mankent	Aksu	2.5	N/A	Run-of-river	Aksu-Energo, LLP	2017
Korinskaya-1	Kora	28.5	121.0	Run-of-river	Korinskaya GES, LLP	2017
Lepsy-2	Lepsy	17.0	40.0	Run-of-river	GES Lepsy, LLP	2016
Verkhne-Baskanskaya-1	Baskan	4.5	50.0	Run-of-river	Baskan Power, LLP	2015
Ryszhan	Keles	2.0	25.0	Run-of-river	SmartReEnergy, LLC	2014
Intumakskaya	Nura	0.6	N/A	Run-of-river	Kazvodkhoz	2013
Karakystakskaya	Karakystak	2.3	107.6	Run-of-river	Zhambylskiye GES, LLC	2013
Tasotkelskaya-1	Chu	9.2	N/A	Run-of-river	Kompaniya A&T Energo, LLP	2013
Sarkandskaya	Sarkand	1.9	50.8	Run-of-river	Firma Tamerlan, LLP	1998/ 2013
Karatalskaya-2	Karatal	4.4	19.8	Run-of-river	Kaskad Karatalskikh GES, LLP	2010
Issyk-2	Issyk	5.1	160.0	Run-of-river	EnergoAlem, LLP	2008
Koshakar-Ata	Keles	1.3	7.6	Run-of-river	SmartReEnergy, LLC	2001
Antonovskaya-3	Lepsy	1.6	N/A	Run-of-river	Kainar-AKB, LLP	1960
Almatyinskaya-2	Kumbelsu	14.3	499.0	Run-of-river	Almaty Power Stations, JSC	1959
Karatalskaya-1	Karatal	10.1	46.2	Run-of-river	KazTzink, LLP	1954

Source: Various[12,41–57]

The majority of existing SHP plants in Kazakhstan as well as SHP potential sites are located on small rivers (less than 200 kilometres in length) in mountainous areas, where elevation differences enable the construction of SHP plants on relatively low-flow watercourses. Both in terms of technical and economic considerations, SHP development potential in Kazakhstan is highest in the south and south-east of the country, where abundant water resources are coupled with an existing power deficit. The most promising rivers for SHP construction in the region are the Ili, Charyn, Chilik, Karatal, Koksu, Tentek, Khorgos, Tekes, Talgar, Major and Minor Almaty, Usek, Aksu, Lepsy, and Yrgaity Rivers.[58]

Data provided by the Almaty Hydroproject Institute and published in an Energy Sector Management Assistance Programme (ESMAP) report in 1997 surveyed SHP potential on rivers across the country. Regional totals of SHP potential, indicating the number of potential sites, potential capacity and estimated annual generation identified by the study, are summarized in Table 2. According to the report, Almaty Oblast alone accounts for nearly half of all SHP potential capacity and generation in the country.[23]

Table 2. **Small Hydropower Development Potential in Kazakhstan**

UES RK zone	*Region*	*Installed capacity range (MW)*	*Number of SHP plants*	*Total potential capacity (MW)*	*Technical potential, annual average (GWh)*
North	Eastern Kazakhstan Oblast	N≤10	58	176.1	704
		10<N≤30	18	377.0	1,669
		Total	76	553.1	2,373
South	Almaty Oblast	N≤10	191	661.7	3,129
		10<N≤30	30	472.7	2,161
		Total	221	1134.4	5,290
	Zhambyl Oblast	2<N≤10	92	208.1	1,020
		10<N≤30	2	23.6	108
		Total	94	231.7	1,128
	Turkestan Oblast	N≤10	112	335.0	1,462
		10<N≤30	4	100.2	452
		Total	116	435.2	1,914
All Kazakhstan		Total of N≤10	453	1,380.9	6,315
		Total of 10<N≤30	54	973.5	4,390
		Total of N≤30	507	2,354.4	10,705

Source: ESMAP[23]

The 2013 Plan for the Development of RES in 2013–2030 and the 2014 Concept of Development of the Fuel and Energy Complex of the Republic of Kazakhstan until 2030 targeted the construction of an additional 518.8 MW of SHP projects by 2030, including 119.1 MW in the North zone and 399.7 MW in the South zone.[33,59] However, most of these projects have not yet been implemented, mainly due to lack of funding. Another large-scale hydropower development plan approved by the Ministry of Energy in 2020 includes a new target to develop 1,500 MW of SHP by 2030.[60]

Ongoing SHP construction has been driven primarily by RES auctions. Several examples of SHP projects approved at recent RES auctions are provided in Table 3.

Table 3. **List of Selected Ongoing Small Hydropower Projects in Kazakhstan**

Name	*Location*	*River*	*Capacity (MW)*	*Developer*	*Expected launch year*	*Project status*
Koktal HPP 1.1	Kerbulakskiy District, Almaty Oblast	Koktal	8.6	National Energy Company Zharyk Energo, LLP	2022	Designed, construction started in 2019
Vekhne-Talaptinskaya	Koksuiskiy District, Almaty Oblast	Koksu	7.0	Bekzat, LLP	2022	Designed, construction started in 2020
N/A	Zharmiskiy district, Eastern Kazakhstan Oblast	N/A	1.0	UBS Power, LLP	2025	Design and approval stage
N/A	Tolebyiskiy District, Turkestan Oblast	Aksu	2.0	Jasyl Qýat, LLP	2025	Design and approval stage
N/A	Kazygutskiy District, Turkestan Oblast	Ulu-chur	1.5	Industrial Cooperative SPK Yntimak	2025	Design and approval stage

Source: KOREM[61]

Note: Status as of mid-2021.

RENEWABLE ENERGY POLICY

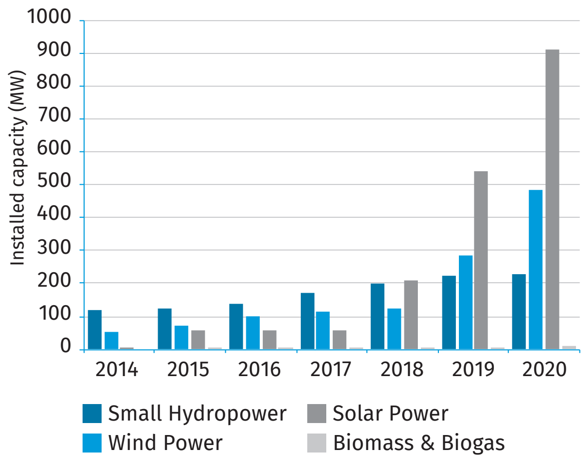
The regulatory framework of Kazakhstan governing RES development includes laws that apply to the power sector as a whole, such as the Law on the Electric Power Industry and the Law on Energy Saving and Energy Efficiency, as well as laws that specifically target the development of RES, including the 2009 Law on Supporting the Use of RES and the 2013 Presidential Decree on the Concept of the Transition of the Republic of Kazakhstan to a Green Economy.[27,33,35,62,63] The latter document established targets for the gradual increase of the share of electricity generation from RES in the coming decades, including a 3 per cent share by 2020, 6 per cent by 2025, 10 per cent by 2030 and 50 per cent by 2050.[63] In pursuit of these targets, additional support measures have been introduced for projects participating in the RES auctions after 1 January 2021, including:

- Provision of financial support from the Government to the FSC, in case of non-fulfilment of its financial obligations towards RES projects. This measure was intended to reduce the risks to investors in RES and accordingly reduce the price at auction for electricity generated by RES facilities, while also increasing the attractiveness of the RES sector in Kazakhstan to investors;

- Extension of the term of Power Purchase Agreements (PPAs) with RES producers from 15 years to 20 years, also aimed at increasing the attractiveness of the RES market to future investors and decreasing tariffs at auctions;
- Introduction of centralized purchase and sale of electric power generated by hydropower plants during the high-flow periods by the FSC, which is intended to distribute this inexpensive electric power among all consumers in the country.[64]

The adopted legislative framework and implemented mechanisms of state support have had a positive impact on RES development in the country. Between 2014 and 2020, the total installed capacity of RES in Kazakhstan increased by nearly 10 times from 178 MW in 2014 to 1,635 MW by the end of 2020 (Figure 6), with 115 power plants operating on RES, accounting for approximately 7 per cent of all installed capacity in the country.[65,66]

Figure 6. **Installed Renewable Energy Capacity by Source in Kazakhstan in 2014–2020 (MW)**



Source: Ministry of Energy[65,66]

Further plans for the development of RES in Kazakhstan include adding approximately 250 MW of RES capacity every year, with particular focus on wind and solar power development in the South and North zones of the UES RK.[66,67] The construction of RES facilities in each zone is carried out considering the resource potential, electricity demand, maximum allowable capacities and the readiness of the infrastructure. This approach ensures that additional RES capacities do not exceed the limits established for reliable operation of the UES RK.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The main sources of financing of the SHP and other RES developments in Kazakhstan are private investments and relevant investment programmes of the national and international development banks. For example, the 24.9 MW Turgusunskaya SHP-1 plant was built in the Eastern Kazakhstan region in 2016–2021 at the cost of KZT 13.39 billion (approximately USD 31.5 million), jointly funded by Kazyna Capital Management, the Kazakhstan Development Bank and the Industry Development Fund, together with private funds of the SHP developer, Turgusun-1 LLP. The engineering, procurement and construction (EPC) contractor of this SHP project was China International Water & Electric Corporation (CWE), a subsidiary of the China Three Gorges Corporation. The Turgusunskaya-1 SHP plant is the first completed project of an emerging cooperation of China and Kazakhstan in the field of hydropower, which is set to expand with construction of the Turgusunskaya-2 and Turgusunskaya-3 SHP plants.[68,69]

The European Bank for Reconstruction and Development (EBRD) has led the investment projects in Kazakhstan, with the Asian Development Bank (ADB), the Asian Infrastructure Investment Bank (AIIB) and the Eurasian Development Bank (EDB) also actively investing in RES projects in the country as well as providing effective assistance to other investors in the implementation of such projects. The United States Agency for International Development (USAID) supported the Government of Kazakhstan and RES investors in the country through the Power the Future project, which has provided support to clean energy development and regional electricity trade.[70,71,72,73]

In 2017, the Green Financial System for Kazakhstan project was established jointly by the Astana International Finance Centre (AIFC) and EBRD. Within the scope of this project, a Concept on Introduction and Development of Green Finance Instruments and Principles was outlined, providing the basis for the development of green finance in the country.[74] Subsequently, the AIFC Green Finance Centre Ltd. was established with the mission of promoting green finance in Kazakhstan and Central Asia, and supporting companies in raising green bonds at the Astana International Exchange (AIX), with the ADB beginning to issue such bonds at the exchange beginning in 2020.[75,76,77]

Feed-in tariffs (FITs) were introduced in 2013 under the Law on Supporting the Use of RES as a mechanism of RES financing.[35] However, the adopted FIT scheme had not provided sufficient benefits to make a significant impact on RES development and Kazakhstan switched from the FIT system to an auction system starting from 2018. Kazakhstan was first among the countries of Central Asia to launch RES auction bidding. The mechanism of auction bidding is aimed at selecting the most effective RES projects at the lowest prices. Kazakhstan Electricity and Power Market Operator (KOREM) JSC provides an electronic trading platform and acts as the auction organizer. The auctions have attracted significant interest from investors, with 172 companies from 12 countries participating in the bidding between 2018 and 2020.[76]

The Ministry of Energy schedules auctions for RES projects with a total capacity of approximately 250 MW in a given year. The capacity quota for SHP projects in 2021 was set at 120 MW.[77,78] A summary of SHP project selection results at RES auctions between 2018 and 2020 is provided in Table 4.

Table 4. **Results of Renewable Energy Auctions for Small Hydropower Projects in Kazakhstan in 2018–2020**

Year	*Installed capacity range*	*Installed capacity allocated for bidding (MW)*	*Installed capacity successfully auctioned (MW)*	*Number of projects selected*	*Ceiling price (KZT/kWh (USD/kWh))*	*Average auction price (KZT/kWh (USD/kWh))*	*Minimum auction price (KZT/kWh (USD/kWh))*
2018	≤10 MW	20	20.6	4	16.71 / 0.04	13.70 (0.03)	12.80 (0.03)
	>10 MW	55	61.5	3		15.08 (0.04)	14.85 (0.04)
2019	≤10 MW	15	7.0	2	15.48 / 0.04	15.45 (0.04)	15.43 (0.04)
	>10 MW	50	0	0		–	–
2020	≤10 MW	20	23.0	9	15.48 / 0.04	14.69 (0.04)	13.48 (0.03)
	>10 MW	100	0	0		–	–

Source: KOREM[78]

Developers of SHP projects approved at the RES auctions are eligible for an array of benefits, including exemption from customs duties on imported equipment, exemption from VAT on electricity sales, as well as support in the form of state in-kind grants. Additional benefits include:

- The right to conclude a PPA with the FSC for the guaranteed purchase of electric energy for a period of 15 years (or 20 years for projects approved after 1 January 2021) from the date of commissioning of the RES facility. The PPA should be based on the auction price, with annual indexation of the tariff after the first year of operation of the RES facility;
- Priority connection to the Dispatching Technological Control Centre of the electrical grids;
- Exemption from payment for services provided by electric grid companies;
- Reservation of the land plot required for construction of the RE facility.[16,64,79]
-

These benefits may be withdrawn if the developer fails to meet the deadline set in the PPA. However, the deadline may be extended provided at least 70 per cent of volume of construction has been completed. Upon commissioning, the FSC is obligated to purchase all electricity generated by the plant at the price set in the PPA. The ceiling price for SHP plants approved for auctions in 2021 was 17.87 KZT/kWh (0.04 USD/kWh).[12]

Under the Law on the Support for the Use of RES, the costs of guaranteed purchase prices used to support RES development are borne by the so-called conditional consumers, which include plants running on fossil fuels, large hydropower plants commissioned before 2016, as well as companies involved in electricity imports. The costs are allocated in proportion to the conditional consumers' electricity deliveries to the grid.[35]

The aforementioned benefits and policies have had a marked impact on the attractiveness of SHP to potential investors. In 2020, SHP proposals from investors at RES auctions exceeded the allotted capacity quota for SHP by a factor of two.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Observed impacts of climate change in Kazakhstan have included a decrease in glacier volume caused by rising temperatures. Studies have shown that intensive melting of glaciers continues in the zone of formation of the runoff of the Syrdarya and Amu Darya Rivers. In the past 50 years, the volume of glaciers has decreased by 20–40 per cent.[80]

Climate change projections for Kazakhstan predict increases in average temperature, precipitation and annual river discharge in the coming decades. Temperatures in Kazakhstan are projected to increase at a faster rate than the global average, with average annual temperature rising by 1–2 °C by 2030 and 2–3 °C by 2050, while precipitation is projected to increase by up to 10 per cent by 2050. Temperature increases are expected to further accelerate the melting of glaciers in the country. The projected high glacier melting rate is expected to cause an increase in river flow and flood risk through the middle of the 21st century. Increasing frequency of floods, mudflows and landslides is expected to exacerbate siltation and lead to the damage and possible destruction of hydropower infrastructure. In the second half of the 21st century, depletion of glaciers is projected to lead to a long-term decline in river flow and a consequent reduction of hydropower potential.[80,81,82,83]

Additionally, many rivers in Kazakhstan are transboundary, shared with neighbouring countries including Kyrgyzstan, Uzbekistan and China. Decreases in flow on these rivers have been causing shortages of water downstream and some reduction in hydropower generation in the country in recent years. The Government of Kazakhstan has been working on resolving issues related to transboundary water management by negotiating agreements with neighbouring countries and taking part in international and regional water management programmes, including the World Bank-sponsored Climate Adaptation and Mitigation Programme for the Aral Sea Basin.[84,85,86,87,88]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The development of SHP plants in Kazakhstan is hindered by several factors:

- The electricity sector in the country is dominated by cheap thermal power plants due to the vast availability of domestic fossil fuel reserves. Thermal power generation is furthermore subsidized by the Government and actively defended by thermal power producers against competition from RES;
- The power distribution infrastructure in the country is largely out of date. It is unable to accommodate significant additional SHP capacity without major upgrades;
- The installed capacity quotas for SHP projects included in the RES auctions are low and much smaller than requested by potential investors. This is mostly due to the restrictions imposed by the outdated power distribution infrastructure, but also due to the RES development policy in the country, which gives preference to wind and solar power;
- The initial investment costs are high due to reliance on imports;
- Long-term funding opportunities are limited;
- The absence of a programme or clear strategy for SHP development in the country beyond 2030 is creating uncertainty for potential investors;
- There is a shortage of up-to-date scientific data on SHP potential in the country;
- There is a lack of qualified and experienced professionals in the SHP development sector of Kazakhstan, particularly those with a good understanding of the integration of SHP with power infrastructure.

Despite the existing obstacles, the outlook for SHP development in the country is positive due to several enablers introduced by the Government for the RES projects, including:

- The regulatory framework in Kazakhstan is strongly supportive of RES development in the country as a whole and provides investors with significant incentives, including customs and tax waivers, waivers of grid connection fees, guaranteed purchase prices and periods and in-kind aid;
- The Energy Ministry of Kazakhstan has outlined, and is in the process of implementing, strategic plans with clear targets for RES development, including the construction of significant additional SHP capacities.

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Kyrgyzstan

Eleonora Kazakova, Chair of the Association of Renewable Energy Sources in the Kyrgyz Republic

KEY FACTS

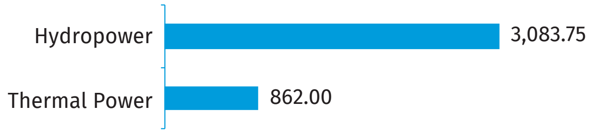
Population	6,523,500 (2020)[1]
Area	199,990 km^2 [2]
Topography	The topography of the Kyrgyz Republic is dominated by the Tien Shan and the Pamir-Alai Mountain Range systems. The highest point is Pobeda Peak (7,439 metres) and the lowest point lies at 480 metres above sea level at the transboundary crossing of the Naryn River on the border with Uzbekistan. Approximately 93 per cent of the country's area is above 1,000 metres, 85 per cent is above 1,500 metres and 42 per cent is above 3,000 metres above sea level.[3]
Climate	A total of four climatic regions can be distinguished on the territory of the Kyrgyz Republic: the Inner Tien Shan, the north-eastern, the north-western and the south-western regions. The climate is sharply continental. Summers in the cities are quite hot, but relatively cool in the mountains. Winters are cold and snowy, especially in the highlands. The average summer temperature in Kyrgyzstan is 27 °C, with average minimum and maximum temperatures of 16 °C and 33 °C, respectively. Winter temperatures average 1 °C, with average minimums and maximums of -12 °C and +10 °C, respectively.[1]
Climate Change	Between 1885 and 2010, temperatures in the Kyrgyz Republic have increased significantly. Moreover, the rate of change has not been linear and has also increased significantly over the past decades. The rate of increase of the average annual temperature in the country was 0.0104 °C per year for the entire observation period. However, over the period from 1960 to 2010, it has more than doubled to 0.0248 °C per year and in the last 20 years (1990-2010) it reached 0.0701 °C per year. The increase in the average annual temperature is almost the same across all climatic zones and regions of the country, except for the Issyk-Kul region. Projections of current temperature trends to 2100 indicate that temperatures in all regions may increase by more than 4 °C, relative to the baseline period 1961–1990.[4,5]
Rain Pattern	Kyrgyzstan receives highly variable amounts of annual precipitation depending on the region and elevation. The largest precipitation volumes are typically observed along the south-eastern slopes of the Fergana Range (1,000 mm), with the Kyrgyz and Chatkal Ranges receiving somewhat less (700–900 mm). A moderate amount falls on the valleys and foothills of the Osh region (300–700 mm) and the Talass and Chuy Valleys (250–500 mm). The lowest precipitation amounts are observed in Inner and Central Tian Shan (200–300 mm), as well as on the western shores of Lake Issyk-Kul (164 mm).[6]
Hydrology	The water resources of Kyrgyzstan include approximately 50 billion m^3 per year of surface runoff from mountain rivers, 13 billion m^3 of potential groundwater reserves, 1,745 billion m^3 of lake water and 650 billion m^3 stored in glaciers. There are 1,923 lakes in Kyrgyzstan, of which the largest are Issyk-Kul, Son-Kul and Chatyr-Kul. Issyk-Kul alone contains approximately 1,731 km^3, or over 99 per cent of all lake water in the country. The mountainous terrain of the republic has led to the formation of a branched river network, with more than 3,500 rivers and streams, of which the longest are the Naryn (807 km), Chu (380 km) and Talas (200 km) Rivers.[2]

ELECTRICITY SECTOR OVERVIEW

The electricity sector in Kyrgyzstan is characterized by several ongoing issues, including the aging of electricity infrastructure, technical losses, electricity tariffs below the cost of production, financial losses and limitations stemming from the interdependence of water discharge and electricity production. All these factors contribute to a decrease in the reliability of the electricity supply to consumers. Additionally, the country is heavily dependent on fossil fuel imports, with domestically-supplied oil and natural gas products accounting for only approximately 5 per cent of total demand.[7]

The total installed capacity of Kyrgyzstan in 2019 stood at approximately 3,946 MW, provided by 7 large hydropower plants (3,030 MW), 18 small hydropower (SHP) plants (54 MW) and 2 thermal plants (862 MW) (Figure 1). Overall, hydropower accounted for approximately 78 per cent of installed capacity and thermal power for the remaining 22 per cent (Figure 2).[8,9,10,11]

Figure 1. **Installed Electricity Capacity by Source in Kyrgyzstan in 2019 (MW).**



Source: GKPEN,[8,9] Tazabek News Agency,[10] Kazakova[11]

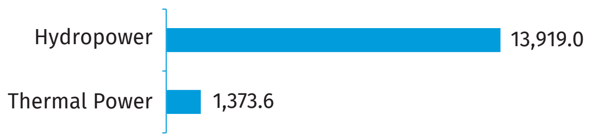
All large hydropower plants and thermal plants in Kyrgyzstan, representing a total installed capacity of 3,892 MW (nearly 99 per cent of the total national installed capacity) and a multi-year average annual generation of 13,478 GWh, are operated by Electric Stations OJSC (Table 1).[8] The installed capacity of the country has recently increased with the commissioning in 2017 of two new power blocks on the Bishkek thermal power plant with a total capacity of 300 MW, as well as two new SHP plants in the Issyk-Kul region with a total capacity of 7 MW.[10,12]

Table 1. **List of Power Plants Operated by Electric Stations OJSC**

Name	*Installed capacity (MW)*	*Average annual generation (GWh)*	*Reservoir volume (m^3)*	*Launch year*
Toktogul HPP	1,200	4,400	19,500.0	1975
Kurpsay HPP	800	2,630	370.0	1982
Tashkumyr HPP	450	1,698	144.0	1987
Shamaldysay HPP	240	902	41.0	1995
Uch-Kurgan HPP	180	820	52.3	1962
Kambarata HPP	120	1,141	70.0	2010
At-Bashy HPP	40	147	9.6	1970
Total hydropower	3,030	11,738	20,186.9	
Bishkek HPP	812	1,740	-	1961
Osh HPP	50	-	-	1966
Total thermal power	862	1,740	-	
Total	3,892	13,478	20,186.9	

Source: GKPEN[8]

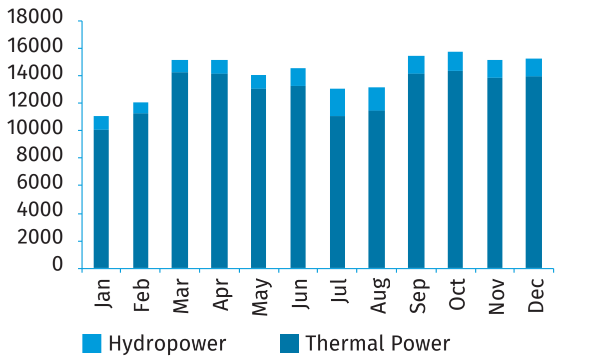
Figure 2. **Annual Electricity Generation by Source in Kyrgyzstan in 2020 (GWh)**



Source: National Statistical Committee[13]

In 2020, electricity generation in Kyrgyzstan amounted to 15,292.6 GWh, with hydropower accounting for 13,919 GWh (91 per cent of the total) and thermal power for 1,373.6 GWh (9 per cent) (Figure 2). Total generation has been fairly stable since 2011, although the relative contributions of hydropower and thermal power have fluctuated from year to year (Figure 3).[13]

Figure 3. **Annual Electricity Generation by Source in Kyrgyzstan in 2009–2020 (GWh)**



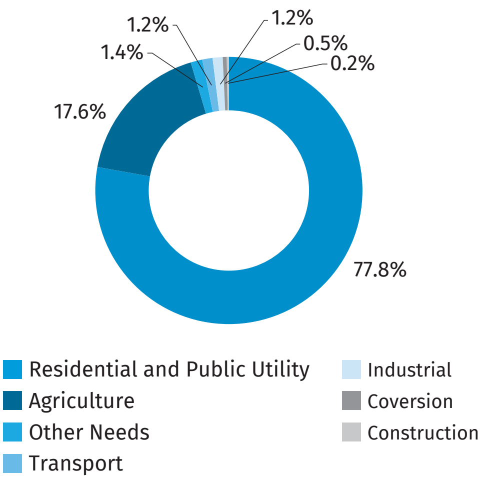
Source: National Statistical Committee[13]

A peculiarity of the energy system of Kyrgyzstan is that 90 per cent of the generating capacity comes from hydropower plants located in the south of the country, while 70 per cent of electricity consumption is concentrated in the north. During the winter, the existing capacity of hydropower plants generally cannot fully satisfy electricity demand and thermal power provides the difference. During the summer, in part due to additional runoff from mountain glaciers, the supply of electricity exceeds demand. At the same time, there is significant demand for irrigation water especially in the downstream areas of major rivers, which competes with water demand from hydropower. Moreover, the shared use of water resources in the Syr Darya basin by Kyrgyzstan, Uzbekistan, Tajikistan and Kazakhstan currently creates water management difficulties and is not sustainable.[14] Instability of generation from hydropower, observed in 2008–2009 and again in 2014–15 and stemming from insufficient runoff, has caused Kyrgyzstan to rely on increased electricity imports.[15]

Domestic consumption of electricity in 2019 amounted to 12,600 GWh (over 83 per cent of all generated electricity for that year). Imports and exports were almost equal, at 269 GWh and 271 GWh, respectively, while losses amounted to 2,514 GWh (nearly 17 per cent of generation).[15,16] Such high losses, reaching 19 per cent in previous years, are explained by aging electrical equipment and the lagging pace of reconstruction and modernization of power grids compared to the growth of electricity consumption. The equipment overload and increased accident rate significantly reduce the efficiency and reliability of the electricity supply in Kyrgyzstan, especially during the fall and winter periods. As a consequence, although electricity access in the country is nominally 100 per cent (with the exception of some remote areas typically inhabited on a seasonal basis), only 76 per cent of consumers (nearly 89 per cent in the city, but 69 per cent in the countryside) have stable access to electricity.[17]

Consumption of electricity in 2019 was dominated by the residential and public utilities sector (78 per cent), followed by industry (nearly 18 per cent), with agriculture, construction, conversion to other forms of energy and transport making up the remainder (over 4 per cent) (Figure 4).[15] Consumption by the residential sector in particular has been on the rise, driven by the very low cost of electric energy relative to the cost of fossil fuels, the prices for which have been fluctuating in parallel with global market trends.

Figure 4. **Share of Electricity Consumption by Sector in Kyrgyzstan in 2019 (%)**



Source: National Statistical Committee[15]

The power grid of the Kyrgyz Republic includes 110–500 kV transmission lines with a total length of 6,683 kilometres, including 541 kilometres of 500 kV lines, 1,748 kilometres of 220 kV lines, 4,353 kilometres of 110 kV lines and 41 kilometres of 35 kV lines (on lease). The grid also includes 190 substations of 110 kV and above with a total capacity of 8,929.2 MVA, including 2 500 kV substations with a total capacity of 1,829 MVA, 14 220 kV substations with a capacity of 2,902 MVA and 174 110 kV substations with a capacity of 4,188.2 MVA. Intersystem connections of 220–500 kV exist with the power systems of Kazakhstan, Tajikistan and Uzbekistan.[18]

In 2001, with the aim of ensuring the effective functioning of the electricity sector, the unified vertically integrated energy system represented by the state-owned JSC Kyrgyzenergo was reorganized and several energy joint stock companies were established by type of activity — generation, transmission and distribution of electricity and heat, with a state ownership share of over 93 per cent.[19] In addition, a programme of privatization in the energy sector was adopted, under which it became possible to privatize SHP plants up to 30 MW.[20]

However, in 2016, the country essentially returned to the model of a vertically integrated market that existed prior to 2001. Recognizing that the operation of the energy sector under the distributed model was inefficient and the fact that energy companies are natural monopolies, the Government decided to create the state company National Energy Holding Company OJSC (NEHK OJSC). This management company again united all the major market participants in the electric power industry: two electric power generation companies, a transmission system operator, four distribution companies and one heating provider.[21]

Electric power generation is mainly provided by the Electric Stations OJSC, which operates nearly all power plants in the country with the exception of some SHP plants. Transmission of electric power through 500/220/110 kV networks is carried out by the National Electric Grid of Kyrgyzstan OJSC (NESK OJSC). Four regional electricity distribution companies are responsible for distributing electricity to end users through 35/10/6/0.4 kV networks: Severelectro OJSC (Bishkek, Chui and Talas regions), Jalalabadelektro OJSC (Jalal-Abad region), Oshelektro OJSC (Osh region) and Vostokelektro OJSC (Issyk-Kul region). In August 2018, Kyrgyz Energy Settlement Center OJSC (KERT JSC) was established to centralize information on electricity flows and losses, publish balance data and perform calculations for all market participants. All of the aforementioned enterprises are included in and are subsidiaries of NEHK OJSC.[22] The purchase, resale and delivery of electricity to end users is also performed by a number of private wholesale electricity buyers and sellers (WPCs) that own or lease transmission lines and substations. In total, 123 companies are licensed to sell electricity, 19 to transmit and 107 to distribute.[23,24]

Prior to 2021, the electric power industry was regulated by the State Property Management Fund (FUGI) and three authorized energy agencies:

- The State Committee for Industry, Energy and Subsoil Use (GKPEN), established in 2016 and performing the functions of formulating and implementing state policy in the energy sector;
- The State Inspectorate for Environmental and Technical Safety (GIETB), ensuring the technical safety, reliability and continuity of generation, transmission, distribution and consumption of electricity, heat and natural gas, as well as the efficiency of their use;
- The State Agency for Regulation of the Fuel and Energy Complex (GARTEK), an authorized anti-monopoly state body that regulates the activities of fuel and energy complex entities through licensing and tariff setting for electricity, heat and natural gas.[25,26,27]

As part of the reforms of state agencies in the Kyrgyz Republic implemented in 2021-2022, GKPEN was transformed into the Ministry of Energy and absorbed both GIETB and GARTEK, with the latter transformed from an independent agency into the Department for Regulation of the Fuel and Energy Complex under the Ministry of Energy. The Ministry of Energy also gained control of 100 per cent of the shares of NEHK, while FUGI was incorporated into the structure of the Ministry of Economy. NEHK remains the managing company of the large state-owned joint-stock energy companies, which in turn, were enlarged, with the NESK OJSC joined with the four regional distribution companies to form a single national grid company, and the Electric Stations OJSC absorbing the heat provider Bishkekteploset OJSC. Consequently, the energy sector is now fully managed by the Ministry of Energy, Electric Stations OJSC is responsible for electricity generation as well as the production, transmission and distribution of heat energy, while NESK OJSC is responsible for the transmission and distribution of electricity.[11,28,29]

GARTEK is officially responsible for calculating and setting energy tariffs. At the same time, tariffs, for generation and for end users, have not been able to cover all costs, leading to a chronic shortage of financial resources needed to invest in the restoration of worn-out assets of the energy system.[30]

Tariff policy in Kyrgyzstan is implemented in accordance with Law of the Kyrgyz Republic No. 56 from 30 October 1996 ("On energy"), Law No. 8 from 28 January 1997 ("On the electric energy sector") and various government resolutions through developing a medium-term tariff policy for electricity and heat (MTTP), which presupposes the gradual elevation of tariffs to cover rising costs. However, the electricity tariff policy is also subject to political considerations, and in practice tariffs for households were frozen between 2014-2017 out of consideration for the economic well-being of low-income households.[27,31]

The MTTP for the years 2020–2022 has essentially retained tariff rates at levels established by the MTTP for 2014–2017, with minor changes to the definition of consumer categories that now include certain institutions for children and the disabled, as well as two consumer categories emerging as a result of recent technological shifts — electric transport and facilities for the mining of cryptocurrencies (Table 2).[32,33,34]

One consequence of the low electricity tariffs is that Kyrgyzstan has trouble attracting private investment in the electric energy sector. Therefore, most major investment projects in the sector are financed by international partners. These have included projects on the modernization of the Toktogul cascade of hydropower plants, as well as the launch of the second hydropower unit at the Kambarata-2 hydropower plant, reconstruction of the At-Bashy hydropower plant and the modernization of the Bishkek thermal power plant. Additional recently completed projects have included power grid upgrades, the construction of additional 500 kV lines and substations and the ongoing "CASA-1,000" Central Asia–South Asia Energy Project, connecting the Kyrgyz Republic and Tajikistan with countries experiencing power shortages, including Afghanistan and Pakistan.[14]

The fuel and energy policy of Kyrgyzstan and its development strategy is implemented in accordance with the National Energy Programme for the period 2008–2010 and the Development Strategy of the Fuel and Energy Complex until 2025 (Resolution of Supreme Council of the Kyrgyz Republic No. 346-IV from 24 April 2008), the Medium-Term Strategy of Electric Power Development of the Kyrgyz Republic for 2012–2017 (Government Decree No. 330 of 28 May 2012), the National Strategy for Sustainable Development of the Kyrgyz Republic for 2013–2017 (Presidential Decree from 21 January 2013) and the Programme of Transition of the Kyrgyz Republic to Sustainable Development for 2013–2017 (Decree of the Government of the Kyrgyz Republic No. 218 from 30 April 2013). In 2018, GKPEN developed and submitted for discussion a draft Framework for the Development of the Fuel and Energy Complex of the Kyrgyz Republic until 2040. The framework defines the goals, priorities and key objectives of the country's energy sector development to 2040, as well as policy mechanisms that will ensure the achievement of these goals.[36] Additionally, having joined the Eurasian Economic Union (EAEU) in 2015, Kyrgyzstan is also expected to participate in the emerging Common Energy Market of the EAEU and is in the process of amending its legislation to include regulations on the development of international electricity networks, trade in the Common Energy Market trade, rules for determining and distributing the capacity of interstate power lines, information exchange and unified rules on access to services of natural monopolies in the field of electric power.[37]

Table 2. **Electricity Tariffs as per MTTP for 2014–2017, 2021–2022**

	Consumer category	*As of Dec. 2017*		*As of Oct. 2021*	
		KGS/ kWh	*USD/ kWh*	*KGS/ kWh*	*USD/ kWh*
1	General population:				
1.1	Consumption up to 700 kWh/ month	0.770	0.011	0.770	0.009
1.2	Consumption greater than 700 kWh/month	2.160	0.031	2.160	0.025
2	Residents of highland and other remote areas:				
2.1	Consumption up to 1000 kWh/ month	0.770	0.011	0.770	0.009
2.2	Consumption greater than 1000 kWh/month	2.160	0.031		
3	Socially-vulnerable households:				
3.1	Consumption up to 700 kWh/ month			0.500	0.006
3.2	Consumption greater than 700 kWh/month			2.160	0.025
4	Pumping stations	0.779	0.011	1.090	0.013
5	Electric transport			1.680	0.020
6	Social institutions for children of the boarding school type, institutions for disabled and/or senior citizens			1.680	0.020
7	Publically-funded entities, industry, agriculture, and others	2.240	0.032	2.520	0.030
8	Entities engaged in mining of cryptocurrencies, gold processing facilities, alcohol production facilities			5.040	0.059
9	Foundries			3.780	0.045
10	Cement plants			3.280	0.039

Source: GARTEK,[32,35]

Note: Exchange rate of KGS to USD: 69.7 KGS/USD in December 2017, 82.8 KGS/USD in December 2020.

SMALL HYDROPOWER SECTOR OVERVIEW

In accordance with Law of the Kyrgyz Republic No. 283 from 31 December 2008 ("On Renewable Energy Sources"), SHP plants are defined as hydropower plants with capacity up to 30 MW.[38] At the same time, as of 2021 there were no SHP plants of above 10 MW capacity in the country and SHP plants in the 10–30 MW range exist only as hypothetical projects.

As of 2020, there were 18 SHP plants operational in the country, with a total installed capacity of 53.75 MW and generating approximately 197.9 GWh in 2020. Of these, nine plants with a total installed capacity of 38.4 MW, are operated by the Chakan HPP OJSC, a subsidiary of NEHK with a government stake of over 93 per cent, while the rest are operated by private companies (Tables 3 and 4).[9,10,39]

Table 3. **List of Existing Public Small Hydropower Plants in Kyrgyzstan**

Name	*Location*	*Capacity (MW)*	*Head*	*Type of Plant*	*Operator*	*Launch year*
Alamedinskaya 6	Grand Chuy canal	6.4	15.0	Run-of-river	"Chakan HPP" OJSC	1958
Alamedinskaya 5	Grand Chuy canal	6.4	15.0	Run-of-river	"Chakan HPP" OJSC	1957
Bystrovskaya	Chu River	8.7	26.3	Run-of-river	"Chakan HPP" OJSC	1954
Alamedinskaya 4	Grand Chuy canal	2.1	12.0	Run-of-river	"Chakan HPP" OJSC	1952
Alamedinskaya 3	Grand Chuy canal	2.1	12.0	Run-of-river	"Chakan HPP" OJSC	1951
Lebedinovskaya	Grand Chuy canal	7.6	28.6	Run-of-river	"Chakan HPP" OJSC	1948
Alamedinskaya 2	Grand Chuy canal	2.5	12.0	Run-of-river	"Chakan HPP" OJSC	1948
Alamedinskaya 1	Grand Chuy canal	2.2	11.8	Run-of-river	"Chakan HPP" OJSC	1945
Malaya HPP	Grand Chuy canal	0.4	10.0	Run-of-river	"Chakan HPP" OJSC	1929

Source: GKPEN,[9] Kyrgyz Energy Settlement Center[39]

The total hydropower potential of the republic is estimated at 28.83 GW in capacity and 245.52 TWh in annual gross power generation.[2] However, estimates for potential SHP capacity in Kyrgyzstan have varied widely, from 180 MW to 900 MW. In 2017, a World Bank meta-study estimated the total SHP potential in the country to be on the order of 409 MW, including both existing plants and undeveloped potential sites. The meta-study was based on the results of several prior studies, including an assessment sponsored by the United Nations Development Programme (UNDP) and conducted in 2015 which identified 63 undeveloped potential sites with a total estimated capacity of 258 MW.[40] The latter figure is cited in recent official documents of the Kyrgyz Republic as the estimate of undeveloped SHP potential, including the GKPEN database of potential SHP sites.[41,42,43] Going by this figure, the total SHP potential capacity of the country including already existing plants is approximately 311.8 MW.

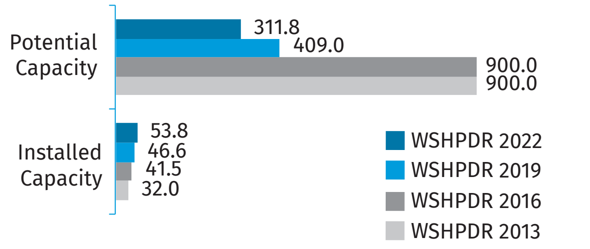
Table 4. **List of Existing Private Small Hydropower Plants in Kyrgyzstan**

Name	*Location*	*Capacity (MW)*	*Head*	*Type of Plant*	*Operator*	*Launch year*
Konur-Olon-skaya	Konur-Olon River	3.6	480.0	Run-of-river	"Konur-Olonskaya HPP" LLC	2019
Kok-Sayskaya	Kok-Say River	3.4	486.0	Run-of-river	"Kok-Sayskaya HPP" LLC	2019
Tegermenti-nskaya	Tegermenty River	3.0	200.0	Run-of-river	"Tegermenty HPP" LLC	2016
Kyrgyz-Ata SHPP	Kyrgyz-Ata River	0.3	30.0	Run-of-river	"Satelit-2005" OJSC	2016
Maryam SHPP	Ak-Suu River	0.5	34.0	Run-of-river	Maryam Agricultural Cooperative	2015
Issyk-Atynskaya	Issyk-Ata River	1.6	70.0	Run-of-river	"ARK Construction Firm" LLC	2008
Naimanskaya	Naiman River	0.6	24.0	Run-of-river	"Naiman HPP" OJSC	2005
Kalininskaya	Karabalta River	1.4	60.0	Run-of-river	"Kalininskaya HPP" LLC	1998
Dzhidalik SHPP	Shahimardan River	1.0	12.0	Run-of-river	"Kadamdzhay Antimony Plant" OJSC	1948

Source: GKPEN,[9] Tazabek News Agency,[10] Kyrgyz Energy Settlement Center[39]

Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP in Kyrgyzstan has increased by over 15 per cent, due to the commissioning of the Kok-Sayskaya and the Konur-Olonskaya SHP plants in 2019. Meanwhile, potential capacity has decreased by nearly 24 per cent due to the availability of more accurate data on official estimates (Figure 5).[44] A partial list of potential sites is displayed in Table 5.

Figure 5. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Kyrgyzstan (MW)**



Source: GKPEN,[9] Tazabek News Agency,[10] Kyrgyz Energy Settlement Center,[39] Open Data Kyrgyzstan,[42] *WSHPDR 2019*,[44] *WSHPDR 2013*,[45] *WSHPDR 2016*[46]

Table 5. **List of Selected Potential Small Hydropower Sites in Kyrgyzstan**

Name	*Location*	*Potential capacity (MW)*	*Head*	*Type of site (new/refurbishment)*
N/A	Chandalash River	10	160	New
N/A	Chon-Aksuu River	11	260	New
N/A	Naryn River	12	24	New
N/A	Kara-Suu River (left)	14	140	New
N/A	Otro-Tokoyskoye reservoir	26	35	New

Source: Open Data Kyrgyzstan[42]

Active construction of SHP plants in Kyrgyzstan was carried out between 1913 and 1963 and reached its peak at the end of the 1950s. Most SHP plants of the period were attached to large enterprises such as factories or collective farms and were often characterized by low technical and economic indicators. In the 1960s, in connection with the mass transition to centralized power supply and the construction of a cascade of large hydropower plants in the south of the country, the further operation of SHP plants was considered inexpedient. Some of them were written off and dismantled, while the rest were transferred to the company Kyrgyzenergoholding. Subsequently, the least economically-efficient SHP plants were mothballed.[47]

In the last two decades, several programmes have been adopted by the Government of the Kyrgyz Republic to promote SHP development, including the Programme for the Development of Small and Medium Electric Power to 2012, National Energy Programme of the Kyrgyz Republic to 2025 and the Green Economy Framework of the Kyrgyz Republic adopted in 2018. These programmes variously stipulated the construction of an additional 41 SHP plants and a total additional SHP capacity of 178 MW to be reached through the refurbishment of abandoned plants, upgrades to operational plants as well as the construction of new plants. However, these ambitious goals have not been realized so far, owing to institutional, technical and financial obstacles, with the few completed projects having largely been financed by international or bilateral donors.[11] For example, the Kok-Sayskaya and the Konur-Olonskaya SHP plants spent over a year in legal limbo following construction before their output was finally cleared for the national grid.[10,39]

RENEWABLE ENERGY POLICY

Kyrgyzstan is endowed with significant potential for unconventional and renewable energy sources (RES), which can be used to increase the country's energy self-sufficiency. RES available in Kyrgyzstan, which include substantial wind, water, solar and biomass potential, can theoretically cover more than 50 per cent of the country's energy needs. At the same time, the technically-feasible capacity to date is at approximately 20 per cent of the overall potential capacity, only 6 per cent is economically feasible and the practical implementation stands at less than 2 per cent.[48] The ratification by Kyrgyzstan of the Charter of the International Renewable Energy Association (IRENA) in January 2021 is expected to expand the range of cooperation and exchange of experience with other countries in the development of RES in the country, the introduction of advanced technologies and attraction of investment in the field of RES.[49]

Legislation regulating the RES sector in Kyrgyzstan includes the Laws of the Kyrgyz Republic "On Energy", "On Electricity", "On Energy Efficiency", "On RES" and "On Licensing and Permitting System in the Kyrgyz Republic".[50] The Law "On RES", passed on 31 December 2008, has since been amended several times. A major obstacle contained in previous revisions had been the excessive burden placed on distribution companies in purchasing electricity from RES. Recent changes to the law, adopted in July 2019, included:

- Compensation of the additional expenses of distribution companies for purchase of electric power generated with the use of RES, which will now be taken into account when calculating and setting national tariffs on electric power for final consumers;
- Revision of the multiplying coefficients for the maximum tariff at which electricity from RES will be purchased, currently set at 1.3 for all types of RES;
- Introduction of quotas for the total amount of electric capacity of RES installations by region and by type of RES, which will be able to receive an increased tariff for 10 years;
- Definition of the tariff for RES installations built outside the quota as the rate of maximum effective tariff minus the cost of transit to the distribution companies;
- Mandating the purchase of electricity from RES by the distribution companies.[51]

Additionally, the Tax Code has been revised to include a tax exemption on profits from the sale of electricity and heat produced using RES for a period of five years from the start of operation of an RES facility and an exemption from VAT on the import of RES equipment.[52]

In accordance with these legislative changes, in December

2020 the state tariff regulator GARTEK issued a single-tariff system for electricity from RES for facilities constructed under the RES quota, as well as for those constructed outside the quota, to stay in effect for a period of 10 years. For RES facilities built under the quota, the final tariff is a product of the maximum allowed tariffs for the final consumer and the multiplying coefficient. In December 2020, it equalled 2.91 KGS/kWh (0.035 USD/kWh). For those outside the quota, the tariff is determined individually based on the cost of transit of the local distribution company.[32,53]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The construction of and generation of electricity by SHP plants in Kyrgyzstan is regulated by Resolution of the Government of the Kyrgyz Republic No. 525 from 30 October 2020, "Regulations on the conditions and procedures for the generation and supply of electricity using renewable energy sources". The regulation replaced previous legislation including the 2017 laws "On the Adoption of the Regulations on Tenders for Construction Rights for Small Hydropower in the Kyrgyz Republic" and amendment to it.[54,55,56] The resolution determines the conditions and procedure of generating and supplying electricity using RES, regulates the legal regimes for generating and supplying electricity using RES within established quotas, outside quotas, on a contractual basis and for own needs, as well as determines the range of entities involved in the process of generating and supplying electricity.[54]

COST OF SMALL HYDROPOWER DEVELOPMENT

Average capital cost estimates for construction of SHP plants at surveyed sites have varied widely. The 2017 World Bank report compiled an overview of the results of several prior studies conducted by a number of government and private agencies between 2006 and 2015, with average capital costs ranging between 1,107 USD/kWh and 3,958 USD/kWh. In terms of specific sites, costs were sometimes drastically different depending on whether peripheral development such as network connections and road construction were included. For example, a survey of the Oi-Alma SHPP-2 potential site conducted in 2011 by AF-Mercados EMI estimated a construction cost of 1,409 USD/kWh without peripheral development and 2,383 USD/kWh including peripheral development. Similarly, development of the Orto-Tokoi Dam SHP site was estimated at 770 USD/kWh without peripheral development and at 1,252 USD/kWh with peripheral development included.[40]

Electricity generated by SHP plants in Kyrgyzstan produces energy savings at the Toktogul hydropower cascade and, in turn, eliminates the need to operate the Bishkek thermal power plant or import electricity. Furthermore, SHP plants could be useful to help maintain the water level of the Toktogul Reservoir in a state of readiness to cover additional hours of peak consumption in winter time. Essentially, the economic benefit of operating an SHP plant in Kyrgyzstan is equal to the difference between the cost of operating that plant and the costs of operating the Bishkek thermal power plant, the power plant acting as a marginal price setter, with the highest cost of electricity generation in the country.[40] In 2019, the average cost of electricity production at the Bishkek thermal power plant was 3.58 KGS/kWh ($0.032 USD/kWh).[57] Thus, the Government of Kyrgyzstan has every reason to encourage the development of all SHP sites whose economic cost of generation is below this threshold.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Projected climate change in Kyrgyzstan is expected to lead to a decrease in hydropower potential, so adaptation and mitigation measures are necessary. For example, expected climate change after the 2030s will lead to changes in water flows and a reduction in the potential of hydropower resources. One significant consequence of the temperature increase is the expected reduction in the duration of the heating period, by 16 per cent by 2050 and by more than 30 per cent by 2080.[4] As a result, an annual Gross Domestic Product (GDP) growth of even 4 per cent would result in the exhaustion of the hydropower potential in Kyrgyzstan within a few decades. This may mean that the development of small and micro-hydropower plants, which in the short term may help to mitigate energy shortages, particularly in remote areas, in the long term may prove unsustainable.[5]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In the absence of state funding for projects to build SHP plants, Kyrgyzstan is in need of ensuring conditions that would attract capital from private investors, as well as concessional loan financing from international financial institutions. At the moment, the most significant barriers and risk factors deterring additional investment in the SHP sector in Kyrgyzstan include the following:

- Natural risks including, siltation, flooding, and bank erosion, potential seismic risk, severe winter weather including ice drift and seasonal instability in water availability;
- Instability in the country's political system, frequent changes in state leadership and the composition of government bodies, corruption in government bodies, including the courts, which investors face when applying to authorized bodies or participating in court hearings;
- Ineffectiveness of the ongoing reforms in the energy sector, lack of a strategic vision for RES development, lack of a government body responsible for RES development, overlapping functions of authorized bodies and lack of an interagency unified approach to RES

development;
- Legal obstacles including the absence of a “water right” concept in the water legislation, difficulties with land allocation, and the lack of hydrological and land cadastral data for regional planning;
- Shortage of state funds and high external debts of the energy sector;
- Shortage of qualified engineering and operational staff in the SHP sector;
- Low demand for alternative energy sources from the general population due to highly subsidized electricity, and lack of environmental awareness;
- Lack of detailed studies of SHP potential and modern best practices in SHP development and operation, as well as a lack of public outreach on the advantages of small-scale power generating facilities.[58,59,60]

Factors beneficial to the development of SHP in Kyrgyzstan include:
- Large untapped SHP potential;
- Available data developed through prior feasibility studies on potential SHP sites and their cost of development;
- Existing framework of preferential tariffs and quotas for RES including SHP;
- The high cost of producing electricity at the Bishkek thermal power plant that creates a need for alternative energy sources.

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Tajikistan

Georgy Petrov, National Academy of Sciences of Tajikistan; and Danila Podobed, International Center on Small Hydro Power (ICSHP)

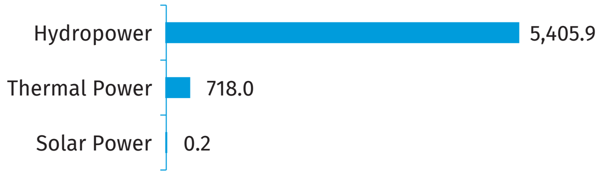
KEY FACTS

Population	9,506,000 (2021)[1]
Area	141,400 km^2 [1]
Topography	Tajikistan is a mountainous country with elevations ranging from 320 metres to 7,495 metres. Ninety-three per cent of the country's territory is covered with mountains, with the Turkestan, Zeravshan, Gissar and Alai Ranges in the north-western and central parts of the country and the Pamir Range in the south-east. Major valleys include the Fergana Valley in the north as well as the Vakhsh and Gissar Valleys in the south-west. The highest point in the country is Ismail Somoni Peak at 7,495 metres.[2]
Climate	The climate in Tajikistan is subtropical, sharply continental and dry, with significant daily and seasonal variations in air temperature. January temperatures range from 22 °C in Panj to -63 °C at Lake Bulunkul in the Gorno-Badakhshan Autonomous Region (GBAO), while July temperatures range from 48 °C (Lower Panj) to -8 °C (Lake Bulunkul). The country receives between 2,100 and 3,170 hours of sunshine per year.[3,4]
Climate Change	Between 1936 and 2014, average annual temperatures increased by 0.1–0.2 °C per decade in the lowlands, by 0.3–0.5 °C per decade at elevations of 1,000–2,500 metres and by 0.2–0.4 °C per decade at elevations above 2,500 metres. An increase in extreme temperatures has also been observed between 1940 and 2005. Climate change projections predict an increase in average annual temperatures of 0.2–0.4 °C by 2030 across all areas of the country, relative to the 1961–1990 baseline period. This is consistent with observed trends over the past 15–20 years. By the end of the 21st century, an increase of up to 5 °C is expected in the southern parts of the country as well as in mountainous areas.[3,4]
Rain Pattern	The average annual amount of precipitation in Tajikistan varies from 273 mm/year to 514 mm/year, averaging 400 mm/year over the last 20 years. However, there is significant regional disparity in rainfall, with the Fedchenko Glacier averaging 2,236 mm/year, while the Ferghana Depression receives only 100 mm. The Eastern Pamirs experience an extreme lack of precipitation, receiving almost no snow or rain.[2,5]
Hydrology	There are more than 25,000 rivers in Tajikistan with a total length of 69,200 km. Of these, 947 rivers are 10–100 km long, 16 rivers are 100–500 km long and 4 rivers are longer than 500 km. The average total annual flow of all rivers in the country is approximately 64 km^3, with average runoff from one square kilometre four times higher than the average for the Central Asia region. A significant part of the surface flow in Tajikistan is fed by glaciers and snowmelt. There are between 8,000 and 14,500 glaciers in Tajikistan, covering 6-8 per cent of the territory of the country. The number of glaciers has been fluctuating as climate change has fractured larger glaciers into multiple smaller ones. The share of glacier discharge in total annual flow of rivers of Tajikistan is 13 km^3. Tajikistan contains approximately 1,300 lakes with a total area of 705 km^2 in additional to 11 artificial reservoirs with a total area of 664 km^2 and a total volume of 15.3 km^3.[6,7,8]

ELECTRICITY SECTOR OVERVIEW

The electricity sector of Tajikistan is dominated by the state-owned Barki Tojik, which operates electric energy infrastructure across the entire country with the exception of the GBAO, a geographically and topographically isolated region in the east part of the country. The private-public company Pamir Energy is the primary power supplier in the GBAO. The total installed capacity of Tajikistan was 6,124.1 MW in 2021, including 6,054.4 MW operated by Barki Tojik, 44.8 MW operated by Pamir Energy, with the remaining 24.9 MW accounted for by small hydropower (SHP) plants operated by independent power producers (IIPs). Hydropower provided 5,405.9 MW (88 per cent) of the total installed capacity, while thermal power provided 718.0 MW (12 per cent) and solar power provided 0.2 MW (less than 1 per cent) (Figure 1).[9]

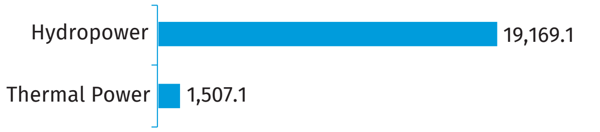
Figure 1. **Installed Electricity Capacity by Source in Tajikistan in 2021 (MW)**



Source: MEWR[9]

Electricity generation in 2019 amounted to 20,676.2 GWh, of which hydropower provided 19,169.1 GWh (93 per cent) and thermal power 1,507.1 GWh (7 per cent), while generation from solar power was negligible (Figure 2).[1] Exports of electricity to Afghanistan, Uzbekistan and Kyrgyzstan amounted to 1,528.4 GWh in 2020, having decreased from 3,175.0 GWh in 2019.[1,10]

Figure 2. **Annual Electricity Generation by Source in Tajikistan in 2019 (GWh)**



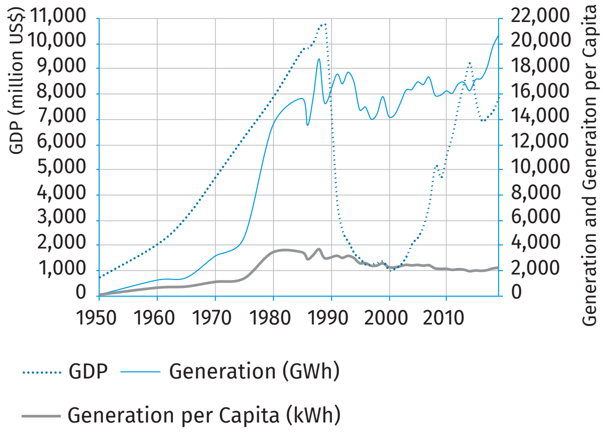
Source: Agency on Statistics[1]

Domestic electricity consumption in Tajikistan amounted to 15,350 GWh in 2019. Electricity consumption in areas serviced by Barki Tojik is dominated by households, industry and agriculture, while consumption in the GBAO is accounted for almost exclusively by household users. Access to electricity in Tajikistan was nearly 100 per cent as of 2019, including 98 per cent in the GBAO. At the same time, temporary caps on electricity use are a common occurrence, particularly in the winter when generation from hydropower declines due to reduced water availability. Per capita annual electricity consumption averages 788 kWh in the GBAO and 1,043 kWh in the rest of Tajikistan. However, accounting for the fact that the GBAO is almost completely deprived of industry, electric transport and mechanized irrigation, per capita consumption in households is nearly the same across all parts of the country.[1,10,11,12,13,14,15,16]

The transmission and distribution grid operated by Barki Tojik includes 489 kilometres of 500 kV power lines, 1,860 kilometres of 220 kV lines, 4,327 kilometres of 110 kV lines, 2,476 kilometres of 35 kV lines and 21,500 kilometres of 6-10-20 kV lines. The distribution system includes 3 500 kV substations, 28 220 kV substations, 174 110 kV substations and 223 35 kV substations. Pamir Energy operates a total of 4,300 kilometres of power lines with distribution substations.[10]

Hydropower has historically been and remains the mainstay of the electric power sector in Tajikistan, providing the bulk of installed electricity capacity and being responsible for almost all generation in the country. Generation from hydropower did not decrease even during the 1990–2000 period, which was marked by an acute crisis across most other economic sectors in the country. At the same time, the per capita annual generation of electricity decreased from 3,700 kWh in 1988 to 1,944 kWh in 2014 due to population growth, increasing again slightly in recent years (Figure 3).[1,8,10,17]

Figure 3. **Dynamics of Generation and Economic Development in Tajikistan in 1950–2010**



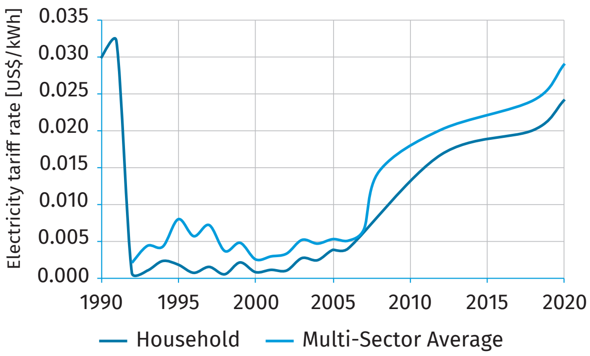
Source: Agency on Statistics,[1] MEWR,[8] Petrov & Akhmedov[17]

Further development of the hydropower sector is a key strategic priority for Tajikistan. The theoretical annual generation potential for hydropower in Tajikistan is estimated at 527 TWh, while the technically and economically feasible potential is estimated at 316 TWh.[10] In order to more fully realize this potential, the country is pursuing several development vectors, including the completion of the 3,600 MW Rogun hydropower plant (with an installed capacity of 400 MW as of 2021), as well as further development of SHP. An expansion of thermal energy capacities as well as of non-hydropower renewable energy sources (RES) is also planned.[9,10,18]

Electricity tariffs in Tajikistan are regulated by Barki Tojik, which uses the cost-based method of price formation. The average electricity tariff for households was 0.032 USD/kWh in 1990, dropping to 0.0042 USD/kWh in the economic crisis following the dissolution of the Soviet Union and has subsequently never recovered to previous levels, equalling only 0.024 USD/kWh in 2020 (Figure 4). Electricity tariffs for state-funded institutions in 2020 likewise equalled 0.024 USD/kWh, while for industry they equalled 0.057 USD/kWh, with the exception of the Tajikistan Aluminium Plant which pays 0.0074 USD/kWh in the summer and 0.0122 USD/kWh in the winter.[19,20,21,22,23]

The World Bank's recommendations issued along with a USD 134 million support package for Barki Tojik in 2020 stipulated raising the household tariff to at least 0.035 USD/kWh in order to ensure the financial stability of the company. The production cost of electricity from generating facilities in Tajikistan that have already paid back their investment costs is estimated at 0.0042 USD/kWh for hydropower and 0.0083 USD/kWh for other energy sources. However, studies have shown that newly built facilities can only pay back their construction cost under the current tariff regime at a construction cost of 1,000 USD/kW or less, suggesting tariffs must be raised if construction of more expensive facilities is to be possible.[17,20,23,24,25]

Figure 4. **Dynamics of Electricity Tariffs in Tajikistan in 1990–2020 (USD/kWh)**

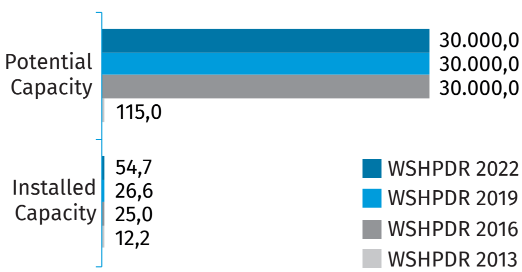


Source: Radio Ozodi,[20] MEWR,[21] Government of Tajikistan[22,23]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of SHP in Tajikistan encompasses hydropower plants with an installed capacity of up to 30 MW.[19] As of 2021, the total installed capacity of SHP up to 30 MW in the country was 142.1 MW, including 44.8 MW operated by Pamir Energy and 24.9 MW operated by IPPs, while the installed capacity of SHP of up to 10 MW was 54.7 MW.[9,10] Potential capacity for SHP of up to 10 MW in Tajikistan has been estimated at 30,000 MW, suggesting that only a small fraction of this potential has been developed.[26] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP of up to 10 MW has more than doubled due to the installation of additional SHP plants and the availability of more accurate data, while the estimate of potential capacity has remained the same due to the absence of recent studies (Figure 5).[27]

Figure 5. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Tajikistan (MW)**



Source: MEWR,[9] Petrov,[10] Valamat-zade,[26] *WSHPDR 2019*,[27] *WSHPDR 2013*,[28] *WSHPDR 2016*[29]

Note: For SHP up to 10 MW.

The first SHP plant was constructed at the Khorog border station in 1913 and several additional SHP plants were built in the 1920s and 1930s. However, large-scale SHP development in the country only began after the Second World War, following the formulation and adoption in 1949–1950 of the Scheme of Use of Hydropower Resources of Small Watercourses for the Electrification of Agriculture in the Tajik Soviet Socialist Republic (SSR). The scheme substantiated the possibility of constructing 784 SHP plants on the territory of the Republic, of which 260 with a total capacity of 44.06 MW were initially scheduled for construction. By 1978, 69 SHP plants had been built with a total capacity of 32 MW. Subsequently, due to a policy reorientation in favour of large hydropower, the implementation of the scheme was suspended.[30,31,32,33]

Interest in SHP development in Tajikistan revived in the early 1990s. Schemes for the development of SHP in the Staro-Matchinskiy, Garmskiy and Jirgitalskiy districts of Tajikistan as well as in the GBAO were drafted in 1991 and 1995, outlining the construction of 112 additional SHP plants with a total installed capacity of nearly 429 MW. A nationwide Programme for the Construction of Small Power Plants for 2007–2020 was developed and adopted between 2006 and 2009. It included 189 SHP plants with a total capacity of 103.2 MW at a total cost of USD 123 million.[25,32,33,34] Under the framework established by these programmes, 155 run-of-river SHP plants were constructed in Tajikistan between 1995 and 2021 (Table 1).[24] A partial list of SHP plants constructed during these years is provided in Table 2.

Table 1. **Small Hydropower Construction in Tajikistan in 1995–2021**

Region	*Active SHP plants*		*Inactive SHP plants*		*Total*	
	Number	*Capacity (MW)*	*Number*	*Capacity (MW)*	*Number*	*Capacity (MW)*
GBAO	15	0.73	20	2.70	35	3.43
Districts of Republican Subordination	53	2.96	21	1.73	74	4.69
Khatlon Region	0	0	8	2.19	8	2.19
Sughd Region	37	1.00	1	0.88	38	1.88
Total	**105**	**4.69**	**50**	**7.50**	**155**	**12.18**

Source: Shupletsov et al.[24]

Table 2. **List of Selected Existing Small Hydropower Plants in Tajikistan**

Name	*Location*	*Capacity (MW)*	*Launch year*
Khatfat	Bartang Valley	0.450	2020
Tajikistan SHP	Murghab	1.500	2018
Tutak	Rasht	0.586	2013
Pitavkul-2	Jirgital	1.104	2012
Kukhistan-1	Gornaya Matcha	0.500	2012

Name	Location	Capacity (MW)	Launch year
Kukhistan	Gornaya Matcha	0.500	2012
Sangikar	Rasht	1.006	2011
Khorma	Baljuvan	0.180	2011
Shirkent	Tursunzade	0.576	2011
Panjrud	Penjikent	0.500	2011
Marzich	Ayni	4.299	2011
Dijik	Ayni	0.260	2011
Shashboloi	Nurobod	0.183	2010
Fatkhabad	Tajikabad	0.282	2010
Artuch	Penjikent	0.500	2008
Khazora-2	Varzob	0.250	2000
Khazora-1	Varzob	0.250	1999

Source: Barki Tojik[14]

The most significant prospects for SHP development in Tajikistan are currently found in the GBAO, as outlined in the Tajikgidroenergproekt study from 1995.[25] Several additional prospective SHP sites identified in central Tajikistan are listed in Table 3.

Table 3. **List of Selected Potential Small Hydropower Sites in Tajikistan**

Location	Potential capacity (MW)
Yormazor	2.3
Nazarmerghan	4.7
Sebzor	11.0
Dombachi	15.0
Khaftkul	18.0

Source: Petrov[10]

RENEWABLE ENERGY POLICY

Tajikistan has adopted a comprehensive package of legislation aimed at regulating, stimulating and creating a preferential environment for the construction and operation of SHP plants and other RES, including the following:

-
- The 1993 Resolution No. 1350 of the Presidium of the Supreme Council of the Republic of Tajikistan providing tax exemptions for SHP plants, non-conventional energy sources and small enterprises for coal mining and processing under construction, as well as outlining the order of construction and operation of RES facilities;
- The 1993 Resolution No. 139 of the Council of Ministers of the Republic of Tajikistan on measures to stimulate the development of small-scale power plants and to increase coal production in the Republic of Tajikistan, authorizing the construction of SHP plants at all operating non-powered hydraulic structures and reservoirs irrespective of their departmental affiliation.[10,35]

These measures have subsequently been superseded by more recent legislation, including:

- The 2007 Law on Investments, which established a system of incentives for foreign investors to participate in the construction of SHP plants;
- The 2015 Law on the Use of RES, which provides a number of benefits and preferences that significantly increased the economic efficiency of SHP plants;
- The 2015 Decree of the Government of the Republic of Tajikistan on the Programme of Development of RES and Construction of SHP plants for 2016–2020.[19,36,37]

The adopted legislative framework stipulates the following specific benefits for SHP plants and other RES facilities:

- Recognition of the use of RES as an environmentally friendly and/or energy saving activity;
- Connection of RES producers to power grids on a preferential basis;
- Obligation of power grid operators to purchase all power generated by RES facilities;
- Exemption from a tax on profits for three years following the start of commercial operation;
- Establishment of accelerated depreciation for RES facilities;
- RES tariff subsidies taking into account the costs of energy production and supporting their development for sale to grid operators.[10,19,35,36,37]

COST OF SMALL HYDROPOWER DEVELOPMENT

The majority of SHP development in Tajikistan takes place with the support of foreign grants, the financial resources of Barki Tojik as well as the developers' private funds. The cost of construction can fluctuate anywhere from 1,420 USD/kW as in the case of a 175 kW SHP plant constructed in Basid Village of the Bartang Valley in 2016 with the support of donations from the Government of Switzerland and private donors to the 10,000 USD/kW required for the reconstruction of the 1.5 MW Ok-su SHP plant in Murghab, completed in 2018. The economic efficiency and payback period of the projects are generally not considered, with the exception of projects taking place in the GBAO, where Pamir Energy takes investment costs into account in electricity tariffs.[10,38,39]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The hydropower resources of Tajikistan are significantly larger than the country's current and projected needs for electricity. Given the low level of utilization of the country's technically and economically feasible hydropower potential (approximately 7 per cent), even the expected reduction in glacier volume and runoff is unlikely to have a significant negative impact on the functioning and development of hydropower in Tajikistan. However, global warming may affect large hydropower used for both electricity generation and irrigation purposes, requiring the construction of additional regulating reservoirs.[10]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The primary barriers to SHP development in Tajikistan include the following:

- Low electricity tariffs that are sufficient to ensure the continuous operation of existing hydropower infrastructure but insufficient to recoup the costs of new construction;
- The established practice of micro-hydropower construction, which are less cost-effective than SHP plants of 500 kW and above;
- Insufficient technological, economic and hydrological data on the feasibility of SHP construction on specific sites;
- The fragmentary and uncoordinated nature of the SHP planning, financing, construction, operation and regulation processes, distributed among a variety of private, public and international stakeholders.

The aforementioned issues can be overcome by the adoption of a systemic approach to the SHP sector that would ensure sufficient data collection on existing and prospective SHP sites, proper planning of the development of supporting infrastructure as well as sectors tangential to SHP, including domestic manufacturing of equipment and the training of technical personnel. Future SHP development can take advantage of several enabling factors, including:

- Massive untapped SHP potential;
- The advantage SHP enjoys over large hydropower with regard to access to sufficient financing.

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Turkmenistan

Ahmet Penjiyev, Turkmen State Institute of Architecture and Civil Engineering*

KEY FACTS

Population	5,942,089 (2019)[1]
Area	491,210 km^2 [2]
Topography	More than 80 per cent of Turkmenistan is occupied by the Kara-Kum Desert, which is bounded in the east by the Amu Darya River and in the west by the Caspian Sea. Major mountain ranges include the Kopet Dagh Range on the southern border with Iran and the Köýtendag Range in the east, which includes Mount Ayrybaba (3,139 metres above sea level), the highest point in the country.[3]
Climate	Turkmenistan has a very dry, continental climate, experiencing extremely hot summers and moderate winters with frequent rain and occasional, but rare, snowfall. Daytime temperatures between May and September can exceed 40 °C, while temperatures in January range between −6 °C and 4 °C.[4]
Climate Change	Turkmenistan is a country at particular risk from climate change, especially in the areas of agriculture, water resources, public health and the integrity of ecosystems. Climate change in Turkmenistan is proceeding at a rapid pace. Between 1993 and 2003, the mean annual temperature increased by 0.18–0.2 °C. By 2100, further temperature increases are projected to range anywhere from 2–3 °C to 6–7 °C. Other shifts in the climate of Turkmenistan have included an increase in the difference of maximum and minimum temperatures as well as an increase in rainfall variability. This has led to prevailing drought-type conditions, on the one hand, and more extreme rainfall events, on the other, with flooding and mudflows becoming more common.[5]
Rain Pattern	Average yearly rainfall in Turkmenistan ranges between 80 and 200 mm. However, the intra-annual as well as the inter-annual distribution of precipitation is highly variable. Most annual precipitation occurs over the course of a few days (typically, two–six); the maximum recorded single-day rainfall was 124 mm. The total amount of annual precipitation in the Kara-Kum Desert can vary from 24 mm to 564 mm.[6]
Hydrology	Major rivers in the country include the Amu Darya (2,540 km), Heray Rud (1,124 km), Morghab (852 km) and Atrek (660 km). The Amu Darya is the longest river in Central Asia and provides 88 per cent of the water resources in the country. Artificial bodies of water include the Kara Kum Canal, one of the largest irrigation and water supply canals in the world, which brings water from the Amu Darya, Morghab and Heray Rud Rivers to the south. The canal enables the irrigation of more than 1 million hectares of land and has a total irrigation potential of 2,353,000 hectares. Meanwhile, the Altyn Asyr reservoir, commissioned in 2009, is supplied by irrigation runoff from territories in the south via a network of collection and conveyance canals and is the most important water resources facility in the north-western desert region.[7,8,9]

ELECTRICITY SECTOR OVERVIEW

The electricity sector of Turkmenistan is dominated by thermal power plants running on natural gas, in addition to a single hydropower plant. In 2017, there were reported to be twelve power plants in operation equipped with a total of 14 steam turbines, 32 gas turbines and three hydropower turbines, with a total installed capacity of 5,178.4 MW.[10,11,12] There is some ambiguity on current total installed capacity, which has been increasing due to upgrades to existing thermal plants. The most recent estimates suggest a total installed capacity of 6,511.2 MW as of January 2021, with the number of power plants remaining the same as in 2017.[13,14] The 2021 installed capacity by energy source is displayed in Figure 1; while more recent data on the individual installed capacities of the power plants currently operational in Turkmenistan are difficult to acquire, available 2017 figures are displayed in Table 1. Table 1 does not account for the upgrades conducted on the Mary steam and gas power plant in 2018, which raised the plant's installed capacity to 3,400 MW.[15]

Figure 1. **Installed Electricity Capacity by Source in Turkmenistan in 2021 (MW)**

Source: Turkmenistan Today,[13] Central Asia News[14]

Table 1. **Major Power Plants in Operation in Turkmenistan in 2017**

Plant	*Type*	*Installed capacity (MW)*
Mary	Steam and gas	1,831.7
Ahal	Gas	648.1
Derweze	Gas	504.4
Turkmenbashy	Steam	420.0
Balkanabat	Gas	380.2
Abadan	Steam and gas	321.0
Awaza	Gas	254.2
Ashgabat	Gas	254.2
Dashoguz	Gas	254.2
Seydi	Steam	160.0
Lebap	Gas	149.2
Hindigush	Hydropower	1.2
	Total	**5,178.4**

Source: Ministry of Energy,[10] Turkmenportal.com,[11] IEEJ,[12] Ministry of Energy[16]

In 2016, annual electricity generation exceeded 24 TWh and electricity exports equalled 3.2 TWh.[17] By comparison, in the first three quarters of 2020, generation equalled 19.3 TWh (a 16.3 per cent increase over the analogous period of 2019), while 3.6 TWh were exported.[13] Electricity consumption for the most recently available year (2016) equalled 16.4 TWh, dominated by the commercial and public services sector and the transport sector.[17,18]

Electricity tariffs in Turkmenistan are set by the state-owned company Turkmenenergo, which owns and operates the grid, manages the electricity market and distributes electricity to the end consumers.[19] Electricity tariffs valid from 1 November 2017 are shown in Table 2.

Table 2. **Electricity Tariffs in Turkmenistan**

Consumer type	*Rates per 100 kwh*
Legal entities financed from the state budget and their equivalents	TMT 3.31 (USD 0.95)
State-owned self-supporting legal entities, non-state-owned legal entities engaged in business, individual entrepreneurs	TMT 6.28 (USD 1.80)
Foreign citizens, stateless persons and refugees	TMT 2.17 (USD 0.62)
Foreign legal entities	USD 3.58
Diplomatic missions, international and intergovernmental organizations	TMT 3.31 (USD 0.95)
Citizens of Turkmenistan who do not engage in entrepreneurial activity	TMT 2.50 (USD 0.71)*

*for consumption above the free-of-charge limit of 35 kWh

Source: News Central Asia[20]

The development plans of Turkmenistan for the years 2019–2025 include the construction of seven additional large-scale energy facilities.[14] By 2035, annual generation is expected to reach 35.5 TWh.[21] Ongoing projects include a gas power plant in the Lebap Region of 432 MW capacity being installed by a joint Japanese-Turkish venture and two gas power plants of 70 MW capacity at the Turkmenbashi Complex of Oil Refineries, whose installation began in September 2020.[22,23] A 10 MW combined solar-wind power plant is planned near the Altyn Asyr reservoir region by 2025.[24] There are also plans to construct high-voltage lines along the Mary–Serakhs–Mashhad route in order to increase electricity exports to Iran. Of additional importance is the planned Turkmenistan–Afghanistan–Pakistan energy bridge, with the Mary-Herat section under construction as of 2020.[14] This 500 kV transmission line will provide upwards of 4 GW of electricity from Turkmenistan, providing for the long-term energy needs of the other two countries and facilitating power trade and exchange among all three participating partners.[17]

SMALL HYDROPOWER SECTOR OVERVIEW

There has been little development of hydropower in Turkmenistan in the last century. There is no nationally-adopted definition of small hydropower (SHP), so the 10 MW definition is adopted for the purposes of the current chapter. The country's only SHP plant, the Hindigush hydropower plant on the Murgab River, was built in 1913 with a capacity of 1.2 MW and remains operational to this day. The country's SHP potential is estimated at 1,300 MW, of which less than 0.1 per cent has been developed. Most of the hydropower potential is located in the Murgab and Amu-Daria River basins, on the Tejen River and the Kara Kum Canal. With Turkmenistan having the world's fourth-largest reserves of natural gas, the cheap cost of gas has discouraged investment in renewable energy.[17,19] Since the *World Small Hydropower Development Report (WSHPDR) 2019*, the SHP sector of the country has not seen any changes, neither in installed nor potential capacity (Figure 2).

Figure 2. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Turkmenistan (MW)**

Sources: *WSHPDR 2019*,[17] UNDP,[19] *WSHPDR 2013*,[25] *WSHPDR 2016*[26]

Previous editions of the *WSHPDR* have reported on plans to expand the hydropower sector in Turkmenistan. These have included the 2011 plans for refurbishment of the Kaushut-Bent and Kolkhoz-Bent SHP plants by the European Bank for Reconstruction and Development, as well as the construction of additional plants along the Kara Kum Canal and the Murgab and Tenjen Rivers.[17,25,26] The proposed projects are listed in Table 3 and Table 4; as of 2021, no progress has taken place with respect to any of these proposals.

Table 3. **Proposed Programme for Small Hydropower Development in Turkmenistan**

Type of construction	*Quantity*	*Potential Capacity (MW)*	*Note*	*Region*
Construction and rehabilitation of existing hydropower plants	3	4.7	Mostly former rural hydropower plants of capacity between 0.8 and 2.7 MW	Lolontan region on Murgab River
Addition of hydropower plants to water management projects	6	52.3	Hydropower plants of capacity between 2.6 and 15 MW	South Turkmenistan, Kara Kum Canal, Murgab and Tenjen Rivers
Total	**9**	**57.0**		

Source: *WSHPDR 2013*[25]

Table 4. **Priority Hydropower Projects in Turkmenistan**

Project	*Potential installed capacity (MW)*	*Location*
Hauznan reservoir HPP	11.7	Kara Kum Canal, Mary
Kopetdag reservoir HPP	15.0	Kara Kum Canal, Ashkhabad
Saryyazin reservoir HPP	12.0	Murgab River, Mary
Tashkeprin HPP	7.0	Murgab River, Mary

Source: *WSHPDR 2013*[25]

While no SHP development is currently taking place in Turkmenistan, the ongoing extension of the return water conveyance network into the Altyn Asyr reservoir could present an opportunity for SHP in the future. The purpose of this project is to redirect irrigation runoff from all irrigated territories in Turkmenistan into the reservoir, thereby accomplishing the following:

- Irrigation of agricultural and marginal pastureland in the north-western part of the country;
- Reversal of soil salinization of irrigated areas by lowering the water table;
- Prevention of evaporative and infiltration losses of irrigation runoff;
- Prevention of the contamination of natural streams, such as the Amu Darya, with irrigation runoff;
- Provision of additional economic opportunities for the region in the form of aquaculture and ecotourism.

The total length of the collection and conveyance channels in the network will be 2,654 km, with the main channel having a length of 720 km and a discharge of 240 m^3/s at the mouth.[9,27] As reduction of evaporative losses is one of the primary goals of the Altyn Asyr project and the associated channel network, installation of solar photovoltaic (PV) panels over the surface of the channels to provide shade while producing energy, as has been proposed in similar environments, presents an additional opportunity. The generated energy could be used in combination with small reservoirs and hydropower turbines to provide energy to pumping stations for irrigation or energy storage, or feed directly into the grid.[17,28]

RENEWABLE ENERGY POLICY

Due to the abundant natural gas reserves in Turkmenistan, development of renewable energy policies and capacities has been slow. The country is estimated to have significant renewable energy potential (Table 5), but some earlier projections estimate a contribution of less than 1 per cent from renewable energy to the overall energy mix of Turkmenistan by 2030.[29]

Table 5. **Estimated Potential of Renewable Energy Resources in Turkmenistan**

Resource	*Technical potential (MW)*
Solar power	655,000
Wind power	10,000
SHP (< 10 MW)	1,300
Total	**666,300**

Source: UNDP[19]

Renewable energy policy in Turkmenistan has been evolving over the last decade. The Law on Renewable Sources of Energy has been in development since 2011, but has not been passed into law as of 2021.[30] In 2014, Turkmenistan established the Solar Energy Institute within the Academy of Sciences of Turkmenistan and in 2018 adopted a plan for the development of cooperation with the International Renewable Energy Agency (IRENA) by 2023.[31,32] Also in 2018, Turkmenistan adopted the State Programme on Energy Efficiency for 2018–2024, which includes stipulations on reducing energy losses and controlling pollution from traditional energy sources.[33] Developments in renewable energy policy in 2020 included negotiations with Turkey and Azerbaijan on trilateral cooperation in the area of renewable energy as well as initial studies on implementing a large-scale solar energy project near the Altyn Asyr reservoir.[34,35]

A key development was the establishment of the Interdepartmental Working Group to draft a National Strategy of Turkmenistan for the Development of Renewable Energy until 2030 in June 2020 and approval of the National Strategy in December of the same year. The strategy puts a particular emphasis on the reduction of greenhouse gas emissions and the development of solar power, taking advantage of the country's considerable solar power potential. Additional plans include the establishment of a National Agency of Renewable Energy.[36]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change in Turkmenistan is expected to increase the incidence of extreme weather events, including both droughts and flooding.[5] This will cause discharge in available water courses to become less predictable and undermine the reliability of potential SHP projects, especially those without a reservoir. An additional hazard for SHP is the observed and projected increase in mudflows during extreme rain events, which could cause significant damage to facilities.[5]

Overall, the hydrological outlook for Turkmenistan projects an expected decrease in precipitation of 8–17 per cent by 2100. The total discharge of the Amu Darya, the country's largest river, is expected to decrease by 5–10 per cent by 2050, while that of the smaller Murgab, Tenjen and Atrek Rivers is expected to decrease by 5–8 per cent by 2030. Local rivers could experience discharge decreasing by as much as 30 per cent during the vegetation period.[5,9]

While these changes would not significantly affect the overall near-term prospects of SHP in the country, given the large gap between the installed capacity and the undeveloped potential, they could outsize local impacts if certain streams were to dry up or change course as a result of shifting precipitation patterns.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers to the development of SHP in Turkmenistan are:

- The low prices for energy produced with traditional fossil fuels (natural gas);
- The continuing lack of a comprehensive regulatory framework and policies for the promotion of renewable energy.[19]

However, in recent years, several factors enabling the development of SHP in Turkmenistan have also emerged, including:

- The increased international emphasis on renewable energy as a whole and the active participation of Turkmenistan in multilateral and bilateral agreements with neighbouring countries as well as international agencies on the development of renewable energy;
- Development of national policy instruments dedicated to promoting renewable energy, of which the most important are the draft Law on Renewable Sources of Energy and the National Strategy of Turkmenistan for the Development of Renewable Energy until 2030;
- The ongoing construction of the return waters conveyance network and the Altyn Asyr project, which can be expected to provide both additional potential capacity and additional demand for SHP in previously remote desert regions of the country once complete.

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38.

Uzbekistan

International Center on Small Hydropower (ICSHP)

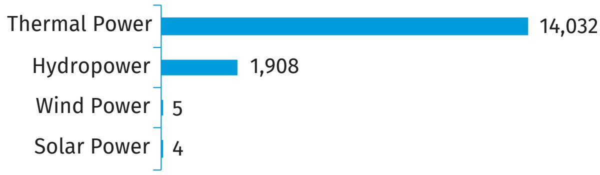
KEY FACTS

Population	35,271,300 (2022)[1]
Area	447,400 km^2[2]
Topography	Uzbekistan can be divided into three physiographical zones: the arid and semi-arid regions, located mainly in the central and western parts of the country and covering 60 per cent of the country's territory; valleys along the Amu Darya and Syr Darya Rivers; and the mountainous region in the east consisting of the Tien Shan and Gissaro-Alay Mountain Ranges.[3] The highest point in the country is Khazret Sultan, at 4,643 metres, while the lowest point is Sariqarnish Kuli, at 12 metres below sea level.[4]
Climate	The climate of Uzbekistan is continental, with hot summers and cool winters. Summer temperatures range from 42–47 °C on the plains to 25–30 °C in the mountains. In winter, temperatures are between -11 °C in the north and 2–3 °C in the south.[3]
Climate Change	Observed effects of climate change in Uzbekistan have included an increase in minimum and maximum air temperatures of 2.0 °C and 1.6 °C, respectively, between 1950 and 2013. Average annual temperatures rose by an average of 0.27 °C per decade over the same period. Climate change projections across several scenarios predict an increase in average annual temperatures of 1.9–5.7 °C by 2071–2090, relative to the 1980–1999 baseline period.[5]
Rain pattern	Most of the country is quite arid, with rainfall occurring mainly between October and April. Average annual rainfall is 264 mm and ranges from 97 mm in the north-west to 425 mm in the mountains in the centre and the south.[3]
Hydrology	Two river basins are found in Uzbekistan, which form the Aral Sea basin: the Amu Darya basin, which covers nearly 82 per cent of the country, and the Syr Darya basin covering approximately 14 per cent of the country. The total average water inflow of the two basins in Uzbekistan is approximately 102.2 km^3.[3] There are 656 rivers in the country, and thousands of small streams that disappear in the desert. Many rivers are redirected for irrigation via extensive canal systems, such as the Amu-Bukhara canal. There are also artificial lakes and reservoirs, many of which are fed by the irrigation runoff.[5,6]

ELECTRICITY SECTOR OVERVIEW

The total installed capacity of Uzbekistan in 2019 was approximately 15,949 MW. The largest share of this total, 14,032 MW (88 per cent) was provided by thermal power, while 1,908 MW (12 per cent) was provided by hydropower, and wind power and solar power contributed a combined 9 MW (less than 1 per cent) (Figure 1).[7]

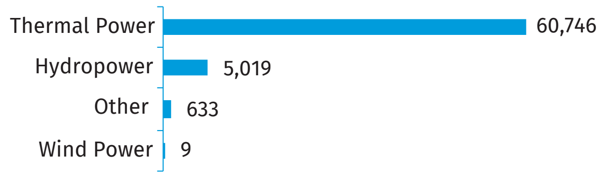
Figure 1. **Installed Electricity Capacity by Source in Uzbekistan in 2019 (MW)**



Source: EES EAEC[7]

Total gross electricity generation in Uzbekistan reached approximately 66,407 GWh in 2020, with thermal power providing 60,746 GWh (91 per cent) of the total, hydropower providing 5,019 GWh (8 per cent), other sources providing 633 GWh (1 per cent) and wind power providing 9 GWh (less than 1 per cent) (Figure 2). Imports of electricity amounted to 11,266 GWh, while exports were 8,627 GWh, with imports exceeding exports for the third year in a row since 2018, reversing the trend of exports exceeding imports observed in 2010–2018.[8]

Figure 2. **Annual Electricity Generation by Source in Uzbekistan in 2020 (GWh)**



Source: CIS Electric Power Council[8]

Access to electricity in Uzbekistan is 100 per cent.[9] Electricity consumption by end users in 2019 amounted to 54,175 GWh, including 17,382 GWh by the industrial sector, 15,058 GWh by agriculture, forestry and fisheries, 13,479 GWh by households, 4,971 GWh by the commercial sector, 2,115 GWh by transport and 1,170 GWh by other users. Transmission losses in 2019 accounted for 3,858 GWh, or approximately 6 per cent of gross generation.[7]

All hydropower plants of Uzbekistan are owned by Uzbekgidroenergo JSC, established in 2017.[10,11] Uzbekgidroenergo JSC was appointed by the Government as the co-coordinating body responsible for the implementation of the Programme for Hydropower Development in Uzbekistan in 2017–2021.[12]

Most of the power generation, transmission and distribution assets in Uzbekistan used to be owned and operated by Uzbekenergo JSC, which was reorganized in 2018–2019 with a view of improving efficiency of the electricity sector in the country following the World Bank recommendations. Uzbekenergo JSC was split into three independent companies: Thermal Power Plants JSC, Uzbekistan National Electric Power Networks JSC and Regional Electric Power Networks JSC.[11] The hydropower assets of Uzbekenergo JSC were transferred to Uzbekgidroenergo JSC in 2017. All these companies are state-owned, although there are plans for the privatization of the energy sector in the country.[13,14]

Uzbekistan used to be part of the Central Asia Integrated Power System (CAIPS), which was established for mutual power trade among the Central-Asian republics of the Soviet Union. In 2009 Uzbekistan halted its participation in CAIPS, although the interconnections between Uzbekistan and other Central Asian countries remained functional.[15]

All consumers in Uzbekistan are connected to the centralized power supply system, except for some remote rural areas that rely mostly on off-grid power generation.[16] The total length of power transmission and distribution lines of all voltages was nearly 264,088 kilometres in 2019, with much of the network's lines being 30 years old on average.[8,17] Aging infrastructure and insufficient investments have increasingly resulted in reliability problems with the power supply, with periodic failures of old transmission and distribution infrastructure and transmission capacity bottlenecks leading to disruptions.[18]

Recognizing these challenges, the Government of Uzbekistan places high priority on energy sector reforms, with the aim of attracting foreign investment funds to carry out reconstruction, modernization and further development of power generating facilities and the power grid.[19] A roadmap to modernize the electricity sector over 2018–2020 was approved in 2018, providing for the implementation of seven investment projects for the modernization of existing and commissioning of new generating capacities of 1,984 MW and with a project cost of USD 2.6 billion.[20] The long-term plans of the roadmap included significantly increasing the installed capacities of all existing energy sources as well as building the first nuclear power plant.[21]

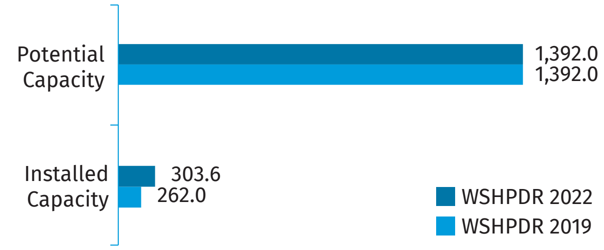
In 2019, the Government introduced a long-term tariff policy for the electric power industry up to 2030, which provides for the financial stability and investment potential of the industry.[22] As of August 2019, electricity tariffs for residential users were 295 UZS/kWh (0.027 USD/kWh) and 450 UZS/kWh (0.041 USD/kWh) for other users.[23]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Uzbekistan is up to 30 MW as stated in the Law of the Republic of Uzbekistan on the Use of Renewable Energy Sources and the Programme of actions for further development of renewable energy and increase of energy efficiency in 2017–2020.[24,25]

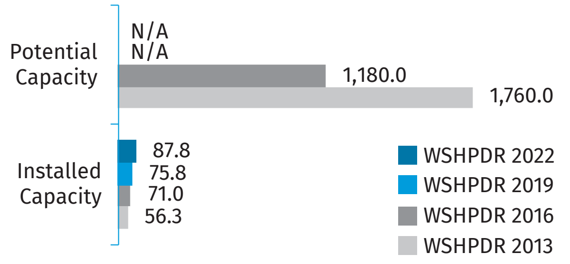
There were over 250 SHP plants up to 30 MW in Uzbekistan at the beginning of the 1960s, operating without a connection to the national grid, but most of these are no longer in use.[26] In 2018, there were 27 SHP plants with installed capacities of up to 30 MW and a total installed capacity of approximately 278 MW. This included 15 SHP plants with installed capacities of up to 10 MW, whose combined installed capacity was 75.8 MW.[2,27] In 2019, several additional SHP plants were commissioned in Uzbekistan, including the 12 MW Tuyabogiz SHP plant in Tashkent Province and two 6 MW SHP plants on the Grand Fergana Canal, while upgrades to the Oktepa SHP plant completed in 2020 increased the installed capacity of the plant from 15 MW to 16.6 MW.[28,29,30] Consequently, the total installed capacity of SHP in Uzbekistan as of 2020 is estimated at 303.6 MW for SHP up to 30 MW and at 87.8 MW for SHP up to 10 MW, increasing by approximately 16 per cent for both SHP categories relative to the *World Small Hydropower Development Report (WSHPDR) 2019*. The technical potential of SHP up to 30 MW has been estimated at approximately 1,392 MW, indicating that nearly 22 per cent has been developed (Figure 3).[27,31] No data on the potential of SHP up to 10 MW are currently available (Figure 4).

Figure 3. **Small Hydropower Capacities up to 30 MW in the WSHPDR 2019/2022 in Uzbekistan (MW)**



Source: Nurmatov,[2] CER & UNDP,[27] The Tashkent Times,[28,29] Uzbekhydroenergo,[30] *WSHPDR 2019*[31]

Figure 4. **Small Hydropower Capacities up to 10 MW in the WSHPDR 2013/2016/2019/2022 in Uzbekistan (MW)**



Source: CER & UNDP,[27] The Tashkent Times,[29] *WSHPDR 2019*,[31] *WSHPDR 2013*,[32] *WSHPDR 2016*[33]

The Government of Uzbekistan is gradually increasing investments in the SHP sector by implementing programmes for building new SHP plants and upgrading the existing ones. For example, the Programme for Hydropower Development in 2017–2021, subsequently amended to extend the planning horizon to 2030, included plans for the construction of 35 SHP plants up to 30 MW with a total installed capacity of 349 MW, as well as plans for increasing the installed capacity of 23 existing SHP plants up to 30 MW to a total capacity of 251.4 MW. These projects were provided with investments from international lenders under credit guarantees by the Government of Uzbekistan.[31,34]

Table 1. **Small Hydropower Projects under Construction in Uzbekistan as of 2021**

Name	*Location*	*Water-course*	*Capacity (MW)*	*Plant type*	*Developer*
Tam-shush	Shahrisabz district, Kash-kadarya region	Aksu River	10.0	Run-of-river	Uzbekhy-droenergo JSC
Kamo-lot	Chirchik, Tashkent region	Chirchik River	8.6	N/A	Uzbekhy-droenergo JSC
Chap-pasu	Shahrisabz district, Kash-kadarya region	Aksu River	8.0	Run-of-river	Uzbekhy-droenergo JSC
Rabat	Shahrisabz district, Kash-kadarya region	Aksu River	6.0	Run-of-river	Uzbekhy-droenergo JSC

Source: Uzbekenergo,[35] Renewable Energy World,[36] Mutin[37]

In 2021, a new programme of hydropower development was announced, targeting the accelerated development of micro- and small hydropower. Planned legislative changes to be enacted as part of the programme include redefining SHP as hydropower plants up to 5 MW, with plants between 5 MW and 30 MW classified as medium hydropower.[38]

Table 2. **Potential Small Hydropower Sites in Uzbekistan**

Name	*Location*	*Watercourse*	*Planned capacity (MW)*	*Planned launch year*
Tashbulak	Shahrisabz district	Tankhizydarya River	3.8	2021-2023
Shurdzhin	Shahrisabz district	Tankhizydarya River	3.8	2023-2025
Suvlisay	Yakkabag district	Kyzyldarya River	7.7	2022-2024
Khitai	Shahrisabz district	Tankhizydarya River	3.0	2026-2028
Samak	Yakkabag district	Kyzyldarya River	6.5	2026-2028
Karatut	Shahrisabz district	Tankhizydarya River	3.0	2028-2030
Kineguzar	Denau district	Sangardak-darya River	22.0	2028-2030

Source: President of the Republic of Uzbekistan[34]

RENEWABLE ENERGY POLICY

Uzbekistan has a legal framework targeting the rational use of natural resources and developed in line with international standards.[39] In particular, in 2019 the Parliament of the Republic of Uzbekistan approved Law of the Republic of Uzbekistan on the Use of Renewable Energy Sources.[24] This law introduced some financial and tax privileges for renewable energy projects. Several state programmes and national action plans are also being implemented with regard to renewable energy, including the Presidential Decree No. PP-3012 On the Programme of Actions for the Further Development of Renewable Energy and Energy Efficiency in Sectors of the Economy and Social Services in 2017–2021.[25,40] Uzbekistan has ratified major United Nations conventions and other international instruments in the field of environmental protection and sustainable development.

A selective review of the current use of alternative energy sources in Uzbekistan carried out in April 2018 by the Uzbekistan State Committee for Statistics found that approximately 3.9 per cent of enterprises in the country had installed at least one type of renewable energy source on the premises, with biogas installations being most popular (2.7 per cent). This indicated a modest increase in the use of alternative energy sources relative to the 3.7 per cent of enterprises using renewable energy in 2017.[39]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key challenges for the development of SHP in Uzbekistan are:

- High availability of thermal power sources such as natural gas and coal;

- Aging energy infrastructure;
- Lack of financing and investment in the renewable energy sector;
- Low electricity prices;
- Lack of clear support mechanisms for SHP development;
- Lack of feasibility studies and available data on SHP potential.

Enabling factors for the development of SHP include the following:

- Large number of formerly operating SHP plants that may potentially be refurbished or rebuilt;
- Significant untapped SHP potential of natural watercourses and canals;
- New policies supporting the development of SHP and other renewable energy sources.

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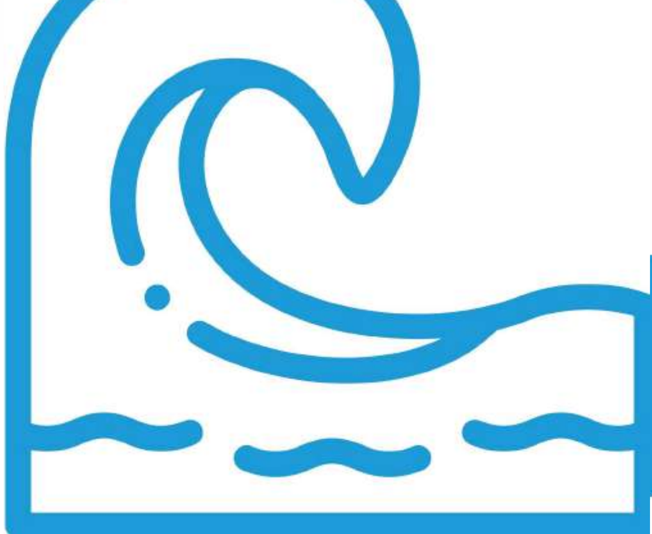


3.2. Eastern Asia

Countries: China, Democratic People's Republic of Korea, Japan, Mongolia, Republic of Korea

INTRODUCTION TO THE REGION

In Eastern Asia, the large and highly diversified electricity sectors of China, Japan and the Republic of Korea (RoK) contrast with those of Mongolia and the Democratic People's Republic of Korea (DPRK), which are comparatively smaller and less diversified. In China, the electricity grid is operated by two state-owned companies. While thermal power remains the dominant energy source, renewable energy sources including hydropower and wind power are expanding as part of the country's energy transition. The electricity sector in the DPRK is entirely state-owned and largely reliant on hydropower and thermal power. By contrast, the electricity sector of Japan is dominated by 10 large regional power utilities, with hundreds of smaller companies entering the electricity market following years of gradual liberalization. In the RoK, nearly 100 per cent of electricity is produced by public utilities, although private electricity companies have a significant presence. Both countries utilize a mix of thermal power sources in addition to nuclear power and renewable energy sources. The electricity sector of Mongolia is fully state-owned. Unlike other countries in Eastern Asia, Mongolia is highly dependent on electricity imports, receiving approximately 20 per cent of its electricity from Russia and China, while domestic generation is heavily dominated by coal-fired power plants.

All countries in the Eastern Asia region possess considerable hydropower capacities, with the exception of Mongolia. Hydropower is the leading source of power generation in the DPRK in terms of installed capacity and second in terms of annual generation. In China and Japan, hydropower plays a supporting role, accounting for approximately 17 per cent of installed capacity in both countries. The RoK also maintains a considerable hydropower capacity, but hydropower plays a comparatively minor role in electricity generation, accounting for approximately 1 per cent of annual generation in 2020. The installed hydropower capacity of Mongolia is less than 2 per cent of the total installed capacity of the country and its contribution to annual electricity generation is minor.

An overview of the electricity sectors of the countries in the Eastern Asia region is provided in Table 1.

Table 1. **Overview of Eastern Asia**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
China	1,411	100	N/A	2,200,000	7,623,600	370,160	1,355,200
DPRK	26	N/A	N/A	8,192	23,854	4,790	11,000
Japan	13	100	N/A	293,897	970,770	50,033	86,314
Mongolia	3	N/A	N/A	1,488	7,135	26	83
RoK	52	100	N/A	133,392	552,160	6,506	7,148
Total	-	-	-	**2,636,969**	-	**431,515**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in Eastern Asia varies across countries. In China, SHP refers to hydropower plants with capacities up to 50 MW, with a further subdivision into mini-hydropower (between 100 kW and 2 MW) and micro-hydropower (up to 100 kW). Plants up to 10 MW are considered small-scale in Mongolia and Japan, although no formal definition of SHP exists in either country. In the RoK, SHP is defined as hydropower plants with a capacity of up to 5 MW. No known official definition of SHP exists in the DPRK.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Eastern Asia (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (<10 MW)*	*Potential capacity (<10 MW)*
China	Up to 50 MW	81,300.0	128,000.0	41,985.0	63,500.0
DPRK	N/A	N/A	N/A	522.1	522.1*
Japan	Up to 10 MW	3,577.0	10,330.0	3,577.0	10,330.0
Mongolia	Up to 10 MW	4.7	129.5	4.7	129.5
RoK	Up to 5 MW	N/A	N/A	199.5	1,500.0
Total	-	-	-	**46,288.3**	**75,981.6**

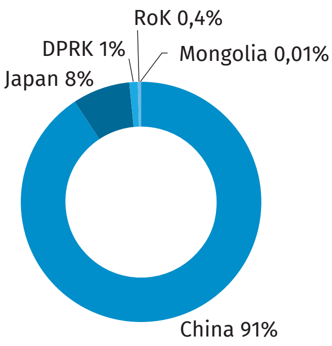
Source: *WSHPDR 2022*[1]

Note: *Based on installed capacity.

In the countries of Eastern Asia, installed capacity for SHP up to 10 MW stands at 46,288.3 MW, or approximately 11 per cent of the total hydropower capacity of the region, while the potential capacity is estimated at 75,981.6 MW. The capacity of SHP up to 10 MW has increased by 1 per cent relative to the *World Small Hydropower Report (WSHPDR) 2019*, mainly due to a re-evaluation of the total installed capacities of the DPRK based on newly available data, as well as increases in the installed capacity of Japan and the RoK. The potential capacity of SHP up to 10 MW in the region has also increased by approximately 1 per cent as a consequence of the re-evaluation of the SHP potentials of the DPRK and Mongolia. Most of the growth in regional SHP capacity over the last decade has been accounted for by the SHP sector of China, although a direct comparison to the dynamics of SHP development in Japan and the RoK is difficult due to differing definitions of SHP. At the same time, the most prospective locations for SHP in China, under both the 50 MW and the 10 MW definition of SHP, have already been developed, while the SHP potential of Japan, the RoK and Mongolia remains largely untapped. No reliable estimate of undeveloped SHP potential in the DPRK is available, but circumstantial evidence suggests the country retains significant untapped hydropower resources.

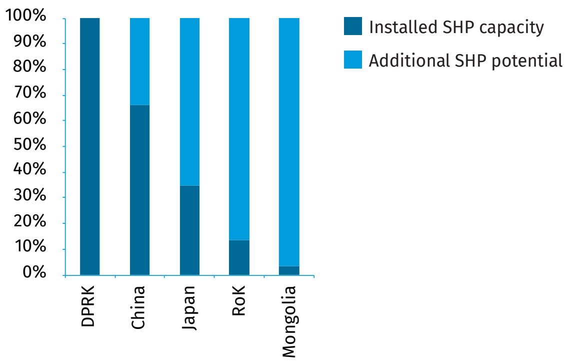
The national share of regional installed capacity for SHP up to 10 MW by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Eastern Asia (%)**



Source: *WSHPDR* 2022[1]

Figure 2. **Utilized Small Hydropower Potential by Country in Eastern Asia (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP up to 10 MW in the case of the DPRK, Japan, RoK and Mongolia. In the case of China, the up to 50 MW definition is used in order to reflect the latest data on domestic SHP development.

In **China**, SHP is a mature technology and is widely adopted all over the country, with 43,957 SHP plants up to 50 MW in operation as of 2020. China has added approximately 2,000 MW of SHP up to 50 MW since the publication of the *WSHPDR 2019*. As of 2020, the installed capacity for SHP up to 50 MW in China was approximately 81,300 MW and potential capacity is estimated at 128,000 MW, indicating that nearly 64 per cent of SHP potential up to 50 MW has been developed. For SHP up to 10 MW, the installed capacity was 41,985 MW as of 2020 while potential capacity is estimated at 63,500 MW, indicating that approximately 66 per cent of the potential for SHP up to 10 MW has been developed. China has set ambitious targets for hydropower development, including building an additional 70,000 MW of hydropower capacity by 2030 and another 70,000 MW by 2050, with SHP intended to account for a share of this additional capacity. Responsibility for SHP development in the country has gradually been shifting towards the private sector.

The estimated total installed capacity of SHP up to 10 MW in the **DPRK** is 522.1 MW. Of this total, 470.9 MW is accounted for by plants constructed prior to 2005, while the remaining 51.2 MW was added between 2016 and 2019. In 2015, the construction of new hydropower projects was announced at six different sites, but no specific data on the potential SHP capacity or current status of these projects are available. Likewise, there is no reliable estimate of the existing SHP potential in the country beyond that which has already been developed. Circumstantial evidence including the topography and hydrological conditions of the DPRK suggest that untapped hydropower potential in the country is considerable. Additionally, many of the previously installed SHP plants, particularly those in the micro- and mini-hydropower capacity range, may no longer be operational or are in need of extensive refurbishment.

In **Japan**, the total installed capacity of SHP under 10 MW is 3,577 MW, while potential capacity is estimated at 10,330 MW, indicating that approximately 35 per cent of the SHP potential in the country has been developed. Japan has a long history of hydropower development, but opportunities for construction of additional large-scale hydropower plants are limited.

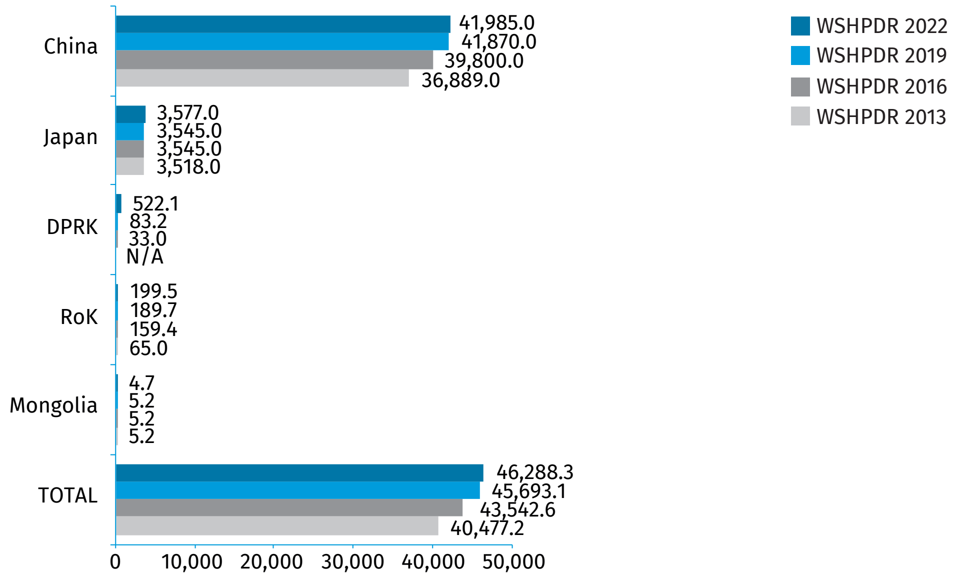
Consequently, construction of SHP plants represents the most active subsector of hydropower development in the country and is promoted by national government policy as well as by non-governmental organizations, agricultural cooperatives and other local organizations.

Mongolia has 10 SHP plants up to 10 MW with a total installed capacity of 4.7 MW. The potential capacity of SHP up to 10 MW in Mongolia is estimated at 129.5 MW, indicating that approximately 3 per cent has been developed. However, five of the existing SHP plants require major restoration work and are currently out of operation, while the other five only operate during the summer. Consequently, SHP in Mongolia is considered a seasonal energy source.

The **RoK** currently has 169 operating plants up to 10 MW with a combined installed capacity of 199.5 MW. Potential capacity for plants up to 10 MW in the RoK is estimated at 1,500 MW, indicating that over 10 per cent has been developed. The SHP sector in the country is undergoing active development, with 14 new plants commissioned in 2018–2019. Ongoing projects include several SHP plants being constructed as auxiliary facilities at the sites of existing thermal power plants.

Changes in the installed SHP capacities of countries in the Eastern Asia region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in Eastern Asia (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

Note: For China, the up to 50 MW definition of SHP is used.

Climate Change and Small Hydropower

Glaciers feeding the two river basins in the Eastern Asia region with the highest degree of hydropower development (the Yellow River and Yangtze River basins) have experienced significant melting with increased temperatures. However, the direction of future changes in precipitation is unclear. In the Yellow River basin, other human economic activities, such as agriculture, have a significantly higher impact on the seasonal changes and streamflow reduction than climate change. Analysis of existing hydropower projects on the Yalong River suggests that modified reservoir operations could help manage the expected future variability in streamflow. Rivers in Mongolia appear to be more sensitive to small changes in temperature and precipitation, affecting generation from hydropower. An example is the Uvurkhangai SHP plant which was abandoned due to insufficient water levels. In Japan, heavy rainfall and suspended sediment in rivers are both projected to increase by up to 25 per cent by 2100, which is expected to increase the operation and maintenance costs of SHP plants.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

One of the greatest barriers to SHP development in **China** are regional development disparities. While nationally, the rate of utilization of existing SHP potential stands at 64 per cent, many provinces in the eastern part of the country have reached a rate of 80 per cent. As the number of available sites for SHP projects decreases, new projects encounter increasing difficulties in terms of land compensation, labour cost, environmental impacts and issues pertaining to resettlement of people in affected areas. Other issues include the overexploitation of the natural environment as a consequence of previous projects and the aging of SHP facilities. Measures adopted to support SHP development in the country have included subsidization of construction and rehabilitation of SHP projects in rural areas, ecological restoration in overexploited regions and improvement of the legal and regulatory system for rural hydropower, among others.

Barriers to SHP development in the **DPRK** include a lack of accurate data on SHP potential, insufficient government funds and international financing options, extreme weather events, aging infrastructure and a lack of domestic capacity to produce generation and automation equipment. At the same time, topographical data suggest that much of the SHP potential in the DPRK remains untapped and many old SHP plants constructed in previous decades can be renovated and rebuilt to meet modern standards.

Barriers to SHP development in **Japan** include insufficient human resources for implementing SHP projects, difficulties with building a wholesale electricity market as well as with researching and developing community grids, lack of clarity on the practicalities of market liberalization and recent legislative focus on the development of wind and solar power. The implementation of SHP projects is additionally complicated by the community-based nature of typical SHP projects, which requires extensive engagement and consultation with local communities. Conditions conducive to SHP development include abundant remaining hydropower potential, extensive local experience and expertise in SHP as well as established financial support schemes.

Today, **Mongolia** faces several problems in developing its SHP potential, which include the lack of specific regulations and legislation, severe winter weather, low feed-in tariffs (FITs), a lack of human resources as well as political and social concerns regarding hydropower development in general. At the same time, the Government of Mongolia has signalled its intention to adopt legislation favourable for SHP development including more attractive FITs. Government agencies have also stepped in to help facilitate private investment in hydropower projects.

Barriers to SHP development in the **RoK** include limited water resources, insufficient development of local technology, dependence on foreign companies in the SHP sector, complaints from environmental groups and local residents, and high initial investment cost for SHP projects. Enabling factors include government support for new and renewable energy projects, abundant untapped SHP undeveloped potential and a broad range of tools to facilitate and attract investment in the SHP sector.

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China

Lina BAO, International Center on Small Hydro Power (ICSHP)

KEY FACTS

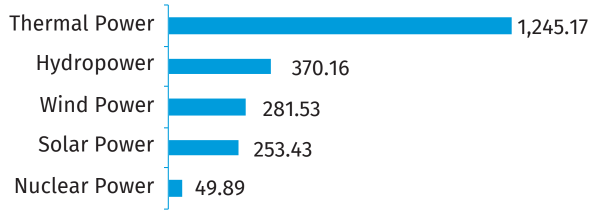
Population	1,410,929,360 (2020)[1]
Area	9,600,000 km^2 [2]
Topography	China is roughly divided into two parts: lowlands in the east, which account for approximately 20 per cent of the total territory, and mountains and plateaus in the west, which constitute the remaining 80 per cent of the country's territory. The highest mountain in China, as well as in the world, is Mount Everest, situated in the Himalayas in the Tibet Autonomous Region, on the border with Nepal. Its summit is 8,848 metres above sea level. The lowest point in China is Ayding Lake, located in Xinjiang Uyghur Autonomous Region, situated at 154 metres below sea level.[2]
Climate	Climate in China is extremely diverse, ranging from tropical in the south to subarctic in the north. Eastern China has subtropical monsoon, temperate monsoon and tropical monsoon climates, whereas north-western China has a temperate continental climate and the Qinghai-Tibet Plateau has an alpine climate. The climate of China is significantly impacted by monsoons, with humid, hot summers and dry, cold winters. The prevailing northerly wind in winter occurs in the inland. It is cold and dry in nature, so there is generally less precipitation and temperatures are lower, especially in the north. The summer monsoon comes from the south-east (Pacific Ocean) and the south-west (Indian Ocean). It is warm and humid and generally leads to a precipitation increase. Minimum temperatures in winter (December–February) range from -27 °C in northern Manchuria to -1 °C in the North China Plain and southern Manchuria, to 4 °C along the middle and lower valleys of the Yangtze River and to 16 °C farther south. Summer temperatures in southern and central China average approximately 27 °C in July. Northern China has a shorter summer season and much cooler nights.[2]
Climate Change	Between 1901 and 2010, the average temperature in mainland China increased by 0.98 °C. While annual average precipitation did not show any statistically significant changes between 1960 and 2010, spring and autumn precipitation declined and summer precipitation increased. Under PCP8.5, temperatures are projected to increase by 4.3 °C in the south-west of the country and by 5.5 °C in the north-west. Under most scenarios, further increases in precipitation across the country are most likely.[3,4]
Rain Pattern	Given its vastness, many degrees of latitude and complex terrain, China has a variety of precipitation levels, including continental monsoon areas. Annual mean rainfall varies from 0 mm in desert regions to 1,500 mm on the east coast, with precipitation levels usually peaking in the summer months between June and August.
Hydrology	There are over 1,500 rivers, each with a drainage area of over 1,000 km^2. The great rivers of China generally flow from west to east, flowing out into the Pacific Ocean. The largest river in China, the Yangtze, is approximately 5,525 kilometres in length and drains an area of approximately 1.8 million km^2. The main river in northern China and the second largest in the country is the Yellow River, approximately 4,671 kilometres in length. The valley of the Yellow River covers an area of 1.5 million km^2.[2]

ELECTRICITY SECTOR OVERVIEW

By the end of 2020, total installed capacity in China had reached approximately 2,200 GW. This consisted of 1,245.17 GW of thermal power (almost 57 per cent), 370.16 GW of hydropower (17 per cent), 281.53 GW of wind power (13 per cent), 253.43 GW of grid-connected solar power (12 per cent) and 49.89 GW of nuclear power (2 per cent) (Figure 1).[5] China has the largest installed capacity of hydropower in the world.

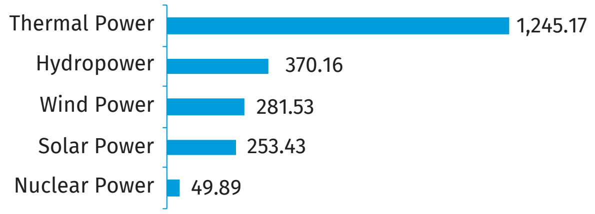
In 2020, electricity generation in China totalled 7,623.6 TWh. Hydropower generation, at 1,355.2 TWh, accounted for 18 per cent of the total generation. Renewable energy generation amounted to 2,082.8 TWh (27 per cent) (Figure 2).[6] Hydropower is still the main source of renewable energy in China, accounting for 65 per cent of total renewable energy generation in 2020.[6]

Figure 1. **Installed Electricity Capacity by Source in China in 2020 (GW)**



Source: NEA[5]

Figure 2. **Annual Electricity Generation by Source in China in 2020 (TWh)**



Source: CEC[6]

China has two grid operating companies, the State Grid Corporation and the South China Grid Corporation. The national grid is divided into six parts. The North-Eastern China Grid, Northern China Grid, Eastern China Grid, Central China Grid, and North-Western China Grid are managed by the State Grid Corporation, while the Southern China Grid is managed by the South China Grid Corporation. Provincial and municipal grid utilities are typically the sole buyers of power from generators and they resell to customers and distribution companies in their service areas.

The National Development and Reform Commission (NDRC) and the State Electricity Regulatory Commission (SERC) share the responsibility for the regulation of the power sector of China. The NDRC's responsibilities include investment, pricing and power plant approval, while the SERC is responsible for the design and oversight of generation markets and implementation of power sector reforms. The SERC also provides advice to the NDRC on pricing and market reforms.[7]

In July 2012, China adopted a Multistep Electricity Price Mechanism, which increased the consumer tariff in multiple steps as the consumption level rose. Peak and off-peak tariffs were also implemented. Consumer tariffs vary across provinces. In 2021, the average tariff for household consumers was 0.542 CNY/kWh (USD 0.085) and the average industrial tariff was 0.635 CNY/kWh (0.100 USD/kWh).[8]

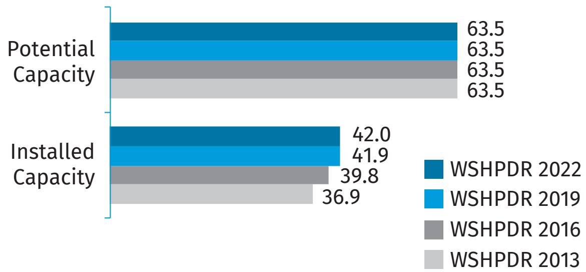
SMALL HYDROPOWER SECTOR OVERVIEW

In China, small hydropower (SHP) refers to capacities of up to 50 MW, with a further classification into mini-hydropower (up to 2 MW) and micro-hydropower (up to 100 kW).

Hydropower in China is a mature technology and SHP is widely used across the country, with plants present in more than 1,700 counties and over 30 provinces, regions and municipalities. China has a unique management system for SHP. Projects in the east connect to the grid directly, while projects in the central and western regions form local grids or isolated mini-grids with their own supply areas.

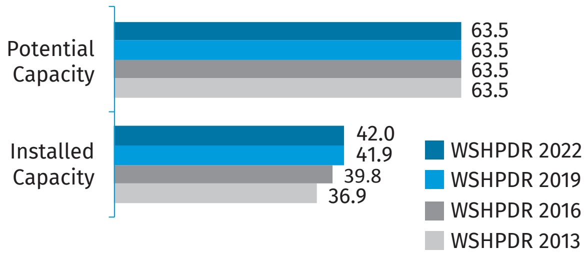
In 2020, there was a total of 43,957 SHP plants up to 50 MW in operation in China, with a total installed capacity of 81,338.28 MW and an annual power generation of approximately 242 TWh.[9] Total potential capacity for SHP up to 50 MW is estimated at 128 GW, indicating that almost 64 per cent of available potential has already been developed. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, potential capacity for SHP up to 50 MW has remained unchanged, whereas the installed capacity increased by approximately 3 per cent due to the commissioning of new plants (Figure 3). For SHP up to 10 MW, the total installed capacity was 41,985 MW as of 2020, and annual power generation in 2020 amounted to approximately 112 TWh. Potential capacity for SHP up to 10 MW is estimated at 63.5 GW, indicating that 66 per cent has been developed.[10] Relative to the *WSHPDR 2019*, the installed capacity of SHP up to 10 MW increased by less than 1 per cent due to the commissioning of new plants, while the estimated potential capacity has remained unchanged (Figure 4).

Figure 3. **Small Hydropower Capacities up to 50 MW in the WSHPDR 2013/2016/2019/2022 in China (GW)**



Source: MWR,[9] *WSHPDR 2013*,[11] *WSHPDR 2016*,[12] *WSHPDR 2019*[13]

Figure 4. **Small Hydropower Capacities up to 10 MW in the WSHPDR 2013/2016/2019/2022 in China (GW)**



Source: ICSHP,[10] *WSHPDR 2013*,[11] *WSHPDR 2016*,[12] *WSHPDR 2019*[13]

In 2020, 69 new SHP plants with a combined capacity of 804.66 MW were put into operation in rural areas of China. Of the newly commissioned plants, almost 67 per cent were within the 10–50 MW capacity range and the remaining 33 per cent were of up to 10 MW capacity. The newly installed capacity is mainly concentrated in the south-west of the country. The total investment cost of these projects equalled CNY 5.86 billion (USD 0.92 billion).[9]

The Government of China has always attached great importance to SHP development, actively supporting and promoting the construction of new power plants for rural electrification and as a green energy replacement for fossil fuel sources. SHP projects have made important contributions to the promotion of river governance, ecological improvements, environmental protection and local social and economic development. At the same time, it should be noted that there are still many weak spots in the planning, design, construction, operation and management of SHP plants in some areas and incentives and restrictions promoting green development of SHP need to be further established. In particular, to ensure the development of green SHP, it is critical to actively adjust to climate change and realize the upgrading of plant quality and efficiency.

RENEWABLE ENERGY POLICY

The Energy Development Strategy Action Plan 2014–2020, launched on 19 November 2014 by the State Council, aims to: (a) increase the share of non-fossil fuel sources in total energy consumption to 15 per cent; (b) reduce the share of coal to less than 62 per cent and (c) reach a more than 10 per cent share of natural gas in the total primary energy mix by 2020.[14] Specific measures include optimizing industrial and energy structures, adjusting the fossil fuel energy structure, further developing hydropower, safely developing nuclear power, actively developing wind power, promoting multipurpose utilization of solar energy and developing biomass energy, along with other renewable energy sources.

The country's target for hydropower development, including SHP, was set to increasing the capacity to 350 GW by 2020 (which was achieved on time), with an additional capacity of 70 GW by 2030 and another 70 GW by 2050. This will bring the total hydropower installed capacity to 490 GW.[15]

The targets for wind energy development are to achieve installed capacities of 200 GW, 400 GW and 1,000 GW by 2020, 2030 and 2050, respectively, and to meet 17 per cent of the total electricity demand in the country through wind power by 2050.[16] The national solar energy utilization target is for solar energy to replace 150 million tons, 310 million tons and 860 million tons of coal and generate approximately 150 TWh, 510 TWh and 2,100 TWh of electricity by 2020, 2030 and 2050, respectively.[17]

The Renewable Energy Law of the People's Republic of China aims to promote the development and utilization of renewable energy, increase energy supply, improve energy efficiency, ensure energy security, protect the environment and achieve sustainable economic and social development goals.[18]

Prices for electricity generated by on-grid plants powered by renewable energy sources are to be determined by the administrative department of price of the State Council according to the renewable energy technology, the regional conditions, the principles of promoting the development and utilization of renewable energy and economic rationality. The prices for each technology should be adjusted in time.[18]

Renewable energy projects are granted financial subsidies under the National Renewable Energy Industry Development Guidance Catalogue, Renewable Energy Industry Development Guidance Catalogue and Renewable Energy Development Conditions. The state grants preferential taxation to projects listed in the Renewable Energy Industry Development Guidance Catalogue.[18]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The Government of China has passed a series of policies to support and encourage local governments and local people to develop SHP resources. These policies include: Self-Construction, Self-Management and Self-Consumption; Electricity Generates Electricity; Small Hydropower Should Have Its Own Supply Area; Small Hydropower Has Priority to Dispatch; Fully Absorb by Grid; and Same Grid Same Tariff. A value-added tax (VAT) for SHP has stood at 6 per cent since 1994, making it much more favourable than the 17 per cent tax levied on large hydropower plants. The Bureau of Hydropower and Rural Electrification Development is also working to promulgate a specialized regulation on rural hydropower development and management.

The Thirteenth Five-Year Plan (2016–2020) set an explicit target to increase SHP capacity by 10 GW. This included 7 GW from the Rural Electrification Programme, the SHP Replacing Firewood Programme and the Refurbishment and Upgrading Programme (for plants built before 2000) and another 3 GW from social investment.[19] At the moment of writing of the present chapter, the Fourteenth Five-Year Plan was being developed.

In 2019, the Ministry of Water Resources and the Ministry of Finance jointly issued the Fourteenth Five-Year Plan for Rural Hydropower Efficiency Expansion and Reconstruction Performance Management Measures, which aims to guide provinces in entrusting third-party agencies to carry out performance evaluations for hydropower projects and to put forward clear requirements for various tasks.

There is no unified feed-in tariff (FIT) for SHP in China. Each province has the right to establish a benchmark price for SHP projects on its territory. These prices are based on the average purchasing price of the provincial electricity grid company as well as the consideration of the supply and demand trends of the electricity market and SHP development costs. In 2017, the average FIT for SHP plants up to 50 MW connected to national grids and local grids was between 0.316 CNY/kWh (0.05 USD/kWh) and 0.252 CNY/kWh (0.04 USD/kWh).[20]

On 6 February 2016, the Ministry of Finance and the Ministry of Water Resources jointly issued the official document Financial Construction (2016) No.27 regarding the extension of the implementation of the SHP Capacity Expansion and Efficiency Improvements Programme. This national SHP refurbishment programme follows the principle of "focus on nature restoration, complemented by artificial modification". The document set the requirements for ecological flow and ecological restoration downstream of SHP plants for the purpose of ecological river recovery at SHP locations. The required measures to ensure green SHP include the following:

- SHP plants should install eco-hydroturbines or other ecological flow discharge facilities to meet the river ecology requirement;
- SHP plants should be equipped with an ecological flow discharge monitoring system or a joint operation system for cascade plants;
- If difficulties with ensuring natural recovery of river ecology after the installation of ecological flow discharge facilities persist, the SHP plant can adopt such measures as connectivity and habitat restoration.[21]

Moreover, a set of technical standard systems, including an SHP programme encompassing design, construction, installation, testing, operation and equipment manufacturing, was established to provide technical support and services for SHP development.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

In July 2011, the Ministry of Finance and the Ministry of Water Resources jointly issued the Interim Measures for the Management of Financial Subsidy Funds for Rural Hydropower Efficiency Expansion and Reconstruction. Through this document, the Government of China allocated financial resources from a dedicated fund for renewable energy development to support measures aimed at improved efficiency, capacity expansion and renovation for rural hydropower. The Government provides fixed subsidies for efficiency enhancement and capacity expansion projects based on the installed capacity after the transformation. The subsidy standard is: 700 CNY/kW (110 USD/kW) in the eastern region, 1,000 CNY/kW (158 USD/kW) in the central region and 1,300 CNY/kW (205 USD/kW) in the western region. The state subsidy funds for a single project shall not exceed 50 per cent of the total investment in the project's efficiency enhancement and capacity expansion.[22]

In addition to investments made by the Government, many private investors have become increasingly involved in hydropower development in the country. Between 1990 and 2000, SHP investment experienced a gradual transition away from central and local government sources, shifting towards corporate enterprises, including foreign ones, with joint ventures and private hydropower plants accounting for an increasing proportion of the newly installed capacity. Projects in which local governments are the investors are more focused on social and public welfare, whilst projects where communities or private entities are the investors are more profit-oriented.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

In the case of China, climate change can have both positive and negative impacts on the hydropower sector. For example, on the one hand, the increase in temperature in spring will reduce the utilization hours of power plants, while, on the other hand, the increase in temperatures and precipitation in winter will increase utilization hours. SHP generation also remains vulnerable to such climate change-induced factors as changes in precipitation, temperature drop and increased frequency and intensity of droughts.[23,24]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key factors hindering SHP development in China include the following:

- It is becoming increasingly difficult to develop the remaining SHP potential due to development disparities across regions. For example, although SHP development has reached 64 per cent of the total potential (SHP up to 50 MW) nationwide, it is actually much higher in some eastern provinces, with some areas reaching a development rate of 80 per cent. Aside from technical difficulties, constraints caused by land compensation, labour cost, environmental and resettlement issues should also be taken into consideration.
- For some rivers, the environment has been damaged by projects that did not strictly implement measures for soil and water conservation and environmental protection. Some rivers were overexploited and some sections dehydrated, affecting the availability of drinking water downstream and the ecology of the whole river.
- The allocation of hydropower resources in some river basins is unreasonable due to past limitations in technology, funding and layout. Some medium and small rivers lack a combined dispatching system.
- Some of the existing plants are already ageing and in a state of disrepair.[25]

The Government of China has implemented various measures to support SHP in the country, particularly focusing on the sustainable development of the technology, including the following:

- Provision of subsidies for the construction and rehabilitation of SHP projects in rural areas, particularly low-income communities;
- Conduct of efficiency enhancement and capacity expansion programmes for rural SHP;

- Ecological restoration of water courses affected by SHP;
- Improvement of the legal and regulatory system for rural hydropower;
- Establishment of a multi-sectoral joint supervision mechanism;
- Conduct of large-scale unannounced investigations and inspections;
- Construction management and social supervision systems.

Further development of the remaining SHP potential in China requires promoting local legislation, strengthening supervision of SHP development and operation as well as strengthening social supervision and resource management. Furthermore, it is necessary to steadily increase the investment in rural SHP projects and ensure the support of SHP development through the national fiscal and tax policy. Finally, new mechanisms for the participation of farmers in SHP development, as a long-term stable source of income, can be explored.[26]

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Democratic People's Republic of Korea

International Center on Small Hydro Power (ICSHP)

KEY FACTS

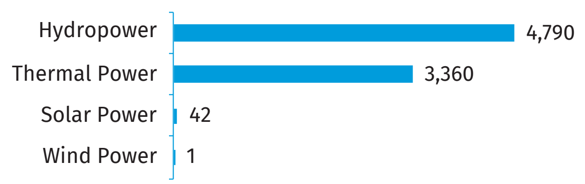
Population	25,778,815 (est. 2020)[1]
Area	120,540 km^2 [1]
Topography	Approximately 80 per cent of the territory of the Democratic People's Republic of Korea (DPRK) is mountainous and rugged.[2] The north and east of the country are composed mainly of high mountains and there are some small plains along the southern and western coastlines.[3] The largest ones are the Pyongyang and Chaeryng Plains, each covering approximately 500 km^2.[4] The highest point is Mount Paektu at 2,744 metres.[5]
Climate	The DPRK is located in the northern part of the Korean Peninsula and the climate of the country is influenced by the Asian continental landmass as well as by oceans to its east and west. The DPRK has a mild temperate climate with four distinct seasons. Summers (from June to August) are hot and humid, with average temperatures of 24 °C, while the spring and winter are dry and cold, with temperatures in the winter (from November to February) averaging -5.5 °C. The annual average temperature is 9–10 °C.[2] In the capital, Pyongyang, daily average minimum and maximum temperatures are -13 °C and -3 °C in January and 20 °C and 29 °C in August.[6]
Climate Change	Observed climate change on the territory of the DPRK has included a rise in winter and spring temperatures of 4.9 °C and 2.4 °C, respectively, between 1918 and 2000. Climate change models predict an increase in summer maximum temperatures of 1.04–6.84 °C by 2100 relative to the 1960–1990 baseline period, depending on the severity of the scenario.[2]
Rain Pattern	Annual precipitation in the DPRK ranges from 810 mm to 1,520 mm and average annual precipitation is 1,054 mm. More than 60 per cent of all rainfall takes place between June and September.[7]
Hydrology	The Yalu River, also known as the Amnok River and located on the border between the DPRK and China, is the longest river in the country, at 790 kilometres. The Yalu River flows from Mount Paektu and continues in a westerly direction into the Yellow Sea. The second longest river in the country is the Tumen River, at 521 kilometres, also begins at Mount Paektu, passing through the DPRK border with Russia and China before draining into the Sea of Japan. The Taedong River is the third longest at 397 kilometres. It originates in the Rangrim Mountains and also drains into the Yellow Sea. Natural lakes in the DPRK are usually small and there are approximately 1,000 artificial lakes, most of which were formed as part of irrigation and hydropower construction projects.[3,4,8]

ELECTRICITY SECTOR OVERVIEW

The net installed capacity of electricity plants in the Democratic People's Republic of Korea (DPRK) was estimated at 8,192 MW in 2020, including 4,790 MW (58 per cent) provided by hydropower, 3,360 MW (41 per cent) provided by thermal power, 42 MW (1 per cent) provided by solar power and approximately 1 MW (less than 1 per cent) provided by wind power (Figure 1).[9,10]

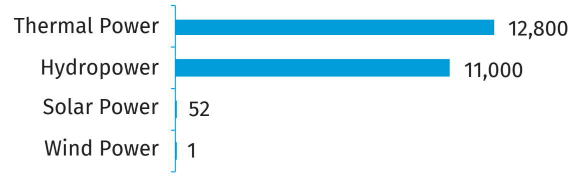
Electricity generation was estimated at 23,854 GWh in 2019. Approximately 12,800 GWh (54 per cent) was generated by thermal power plants and another 11,000 GWh (46 per cent) was generated by hydropower plants, while the remaining 53 GWh (less than 1 per cent) was accounted for by solar power and wind power (Figure 2).[10] Off-grid solar power in the DPRK has expanded considerably in recent years, with approximately 55 per cent of households equipped with solar panels in 2019, but still accounts for a tiny fraction of total electricity generation in the country.[11]

Figure 1. **Installed Electricity Capacity by Source in the Democratic People's Republic of Korea in 2020 (MW)**



Source: IRENA[10]

Figure 2. **Annual Electricity Generation by Source in the Democratic People's Republic of Korea in 2019 (GWh)**



Source: IRENA[10]

Electricity generation in the DPRK has been affected by climate change and the sanctions of the United Nations Security Council. Climate change has led to severe weather conditions, with droughts, floods or both occurring yearly since 2014. At the end of August 2016, there was an extensive rainfall in the province of North Hamyong, causing the Tumen River to flood.[12] Between January and July of 2017, there was a 30–80 per cent decrease in rainfall (compared to the average).[13] In the past, this type of severe weather affected hydropower plants negatively, rendering them inoperable.[14,15] In addition to this, the sanctions imposed by the Security Council have made it difficult for the country to trade and in particular to import oil, a resource that is not available domestically, which has in turn adversely affected all economic activities in the country.[16]

The supply of electricity in the DPRK consistently falls short of electricity demand.[17] Many areas outside of Pyongyang receive a modest amount of power and power outages are a regular occurrence throughout the country.[18] Electricity rationing is also common. For example, in rural areas electricity is only available for a few hours per day.[19]

Estimates of electricity access in the DPRK range anywhere from 26 per cent to over 50 per cent. While most of the population has at least some access to electricity, daily availability may be limited to as little as a few hours or none at all.[11,20,21]

The United Nations Development Programme (UNDP) carried out the Sustainable Energy Solutions for Rural Livelihoods in the DPRK project between 2015 and 2019, among other targets, aiming to improve rural electricity access for individual rural households, promote energy saving technology and develop local technical capacity in electricity generation from renewable energy sources. The project involved the installation of hundreds of solar photovoltaic (PV) systems and energy-efficient technologies at the community and household level and resulted in an estimated electricity savings of 2.4 GWh/year in the agricultural sector.[22] There have also been multiple Global Environmental Fund (GEF) projects in the DPRK, which have helped to increase the electrification rate in rural areas of the country, including the Project on Small Wind Energy Development and Promotion in Rural Areas (SWEDPRA).[23]

The electricity infrastructure of the country is outdated, inefficient and in need of refurbishment, with some of the generation and transmission equipment dating back several decades. Modernizing the electricity sector has been a priority for the Government of the DPRK; in particular, upgrading generating and transmission capacities to increase efficiency and reduce losses.[24] In 2015, electricity consumed by the energy industry and other losses were estimated at 3,475 GWh. The Government of the DPRK has made a commitment to reducing power transmission and distribution losses by 6 per cent by 2030. In 2017, the Government also announced plans for the construction of the new large-scale Tanchon hydropower plant, which is expected to alleviate the electricity supply problem.[25,26] The Tanchon project continued apace through 2019, but progress had slowed as of 2020.[27]

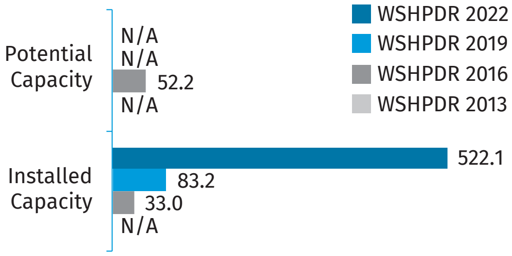
Key ministries involved with the electricity sector include the Ministry of Electric Power Industry, the Ministry of Atomic Energy and the Ministry of Coal Industry. The County People's Committees (CPC) represent the lowest administrative level providing supporting services and facilities to the rural population, including in matters of electricity access.[19] Finally, the Ministry of State Construction Control is responsible for approving construction projects (such as hydropower plants) and their locations.[28]

The electricity tariff system in the DPRK has been undergoing dramatic changes in recent years. Historically, electricity has been provided at the symbolic price of 0.12 KPW/kW (0.000015 USD/kWh) and usage was estimated by house visits from administrative staff. However, with electricity access extremely limited in much of the country in recent decades, black market schemes have in practice often replaced formal payments. In 2017, the Government installed electricity meters in Pyongyang, charging a rate of 35 KPW/kW (0.004375 USD/kWh). Since 2020, an additional experimental measure requires households in Pyongyang with above-average electricity use to pay a rate of 50 USD/month, with a six-month advance payment requirement.[29,30]

SMALL HYDROPOWER SECTOR OVERVIEW

For the purposes of this chapter, small hydropower (SHP) is defined as hydropower plants with a capacity of 10 MW or less. Challenges in data access for the DPRK mean that reliable figures on SHP capacity are not available, but it is estimated that the total installed capacity of SHP in the country as of 2005 was approximately 470.9 MW.[31] Additional SHP capacities commissioned between 2016 and 2019 have been estimated at 51.2 MW (Table 1).[24,32,33,34] Total installed SHP capacity in the DPRK is thus estimated at 522.1 MW, although it is suspected some of this capacity is not currently operational. Data on SHP potential are not available. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed SHP capacity has increased more than fivefold, due to the inclusion of more comprehensive data on historical SHP construction (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in the Democratic People's Republic of Korea (MW)**



Source: *WSHPDR 2019*,[24] Yoon,[31] UNFCCC,[33] UNDP DPRK,[34] *WHSPDR 2013*,[35] *WHSPDR 2016*[36]

Table 1. **List of Selected Small Hydropower Plants in the Democratic People's Republic of Korea (MW)**

Name	*Location*	*Capacity (MW)*	*Plant type*
Hamhung No.1	Kumjin River	10.00	Reservoir
Ryesonggang No. 3	Tosan County	10.00	Reservoir
Ryesonggang No. 4	Kumchon Country	10.00	Reservoir
Ryesonggang No. 5	Kumchon Country	10.00	Reservoir
Kumya	Kumya County	8.00	Reservoir
Hoechang factory No. 1	Hoechang County	1.60	N/A
Hoechang factory No. 2	Hoechang County	1.60	N/A
Myongchon	Jangyon County	0.60	N/A
Hoechang factory No. 3	Hoechang County	0.20	N/A

Source: UNFCCC ,[33] UNDP DPRK[34]

The DPRK has an extensive history of SHP development. Before 1945, hydropower supplied 100 per cent of the electricity needs of the territory that became the DPRK. In the 1960s, the Government of the DPRK launched a programme of thermal power construction with the assistance of China and the Soviet Union to meet rising electricity demand and to address inefficiencies of aging hydropower plants. However, due to the multi-faceted economic crisis facing the country in the 1990s electricity production increasingly failed to meet demand and construction of SHP plants was promoted as a self-reliant solution. Nearly 7,000 SHP plants were constructed nationwide by 2005. The electricity supplied by these SHP plants did not meet expectations, and the programme was eventually discontinued.[31]

Apart from the announcements on the progress of the Tanchon power plant, information about hydropower projects in the DPRK is limited. In 2015, construction of new hydropower projects in Kangwon Province was announced for six different sites: Kosong, Hoeyang, Ichon, Phyonggang, Sepho and Anbyon. These projects are expected to be small-scale, but their exact capacity is unknown.[37] Furthermore, on the country's west coast many rivers, reservoirs, irrigation canal networks and tidal dykes are favourable for large-, medium- and small-sized hydropower development, indicating additional potential SHP capacity. These potential SHP sites vary in heads, with nearly 80 per cent of the sites having heads lower than 15 metres, of which 50 per cent have a head of 5 metres. Unfortunately, specific data on SHP potential capacity at these sites are not available.[24,38]

As part of the Sustainable Rural Energy Development Programme (SRED), micro-hydropower development has been encouraged for rural areas, however the programme was suspended in 2007 and was reformulated and approved by UNDP in 2010. In July 2013, as part of the SRED programme, the 600 kW Myongchon hydropower plant at Myongchon Co-operative Farm in Jangyon County was rehabilitated and the International Center on Small Hydro Power (ICSHP) provided technical support in its rehabillitation.[39] Another example of micro-hydropower is the 200 kW plant in Hoechang County, which is used to provide power to a food processing factory.[34]

RENEWABLE ENERGY POLICY

The national emblem of the DPRK includes the image of a hydropower dam, hence it is no surprise that the Government's energy policy is oriented towards non-fossil fuel options. These include formal policies for the development of decentralized small-scale power generation facilities and for the promotion of the development and use of renewable energy, namely the Law of Medium- and Small-Size Power Stations in the DPRK (2007) and the Law on Renewable Energy in the DPRK (2013). There are also policies targeting thermal power generation, which aim to solve the issue of ageing infrastructure and of the transmission and distribution network. Other approaches such as the expansion of the number of wind power plants are also being employed, which indicate the Government's efforts to reduce dependency on oil imports as it is unavailable domestically.[17] Furthermore, provinces, cities and counties are encouraged to develop medium- and small-scale power plants and ensure their steady operation.[24]

The DPRK is also a state party to several of the most important environmental conventions, such as the United Nations Framework Convention on Climate Change (UNFCCC). The country signed the Paris Agreement and prepared its own Intended Nationally Determined Contribution (INDC) in 2016 to reduce greenhouse gas emissions. In this document, the DPRK lists measures for the realization of greenhouse gas reduction targets, the construction and scaling-up of on-grid power plants as well as off-grid generating systems based on renewable energy resources. Mitigation measures prioritized for conditional contributions are also listed, such as the construction of a 2,000 MW nuclear power plant, 1,000 MW of grid-connected solar PV systems, a total of 500 MW of off-shore wind farms and another 500 MW of on-shore wind farms.[25] The Government aims to reach a total renewable energy capacity of 5,000 MW by 2044, with focus on wind power development.[11]

BARRIERS AND ENABLER FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers to the development of SHP in the DPRK include:

- Lack of data and information on nearly every aspect of the national economy, as well as on the hydropower potential of rivers and specific sites;
- Lack of government funds and external financing due to sanctions and other factors;
- Extreme weather events causing damage to infrastructure;
- Inadequate technical capacities, particularly at provincial and local levels and inaccurate and untimely information and forecasts;
- Lack of domestic capacity to produce generation equipment including turbines, power systems and automation technologies.

Enablers for SHP development in the country include:

- Topography that suggests considerable remaining SHP potential in the form of small mountain rivers;
- Substantial potential for the rehabilitation of thousands of old SHP plants constructed in previous decades and likely being out of operation or operating far below nameplate capacity.

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Japan

Tokihiko Fujimoto, Meiji University

KEY FACTS

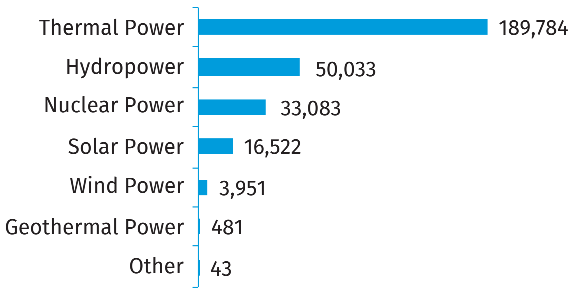
Population	12,5360,000 (2021)[1]
Area	377,962 km^2 [2]
Topography	The country consists of 6,852 islands lying in a volcanic zone. Sixty-seven per cent is of the country's land area is mountainous. The highest point is Mount Fuji, at 3,776 metres above sea level. The coastline is 29,751 kilometres long.[2]
Climate	The climate in Japan varies from south to north. While the south of the country lies in the tropical zone, the north has a subarctic climate. The average annual temperatures range from 23.8 °C in the southernmost city of Naha, Okinawa, to 10.0 °C in the northernmost city of Sapporo, Hokkaido. The capital city, Tokyo, had an average temperature of 16.5 °C in 2020.[3]
Climate Change	Over the period of 1896–2016, the mean annual temperature has been rising at a rate of 1.19 °C per 100 years, with springtime temperatures rising faster than other seasons, at a rate of 1.38 °C per 100 years.[4] In recent years, natural disasters linked to climate change have affected Japan on an annual basis, leading to human casualties. These have included the flooding caused by heavy rains in northern Kyushu (2017) and Kurashiki City in Okayama Prefecture (2018), the destructive typhoon flood on the Chikuma River in Nagano (2019) and the flooding of the Kuma River in Kumamoto Prefecture (2020).[5] Projections of future climate change in Japan predict a rise in temperatures of approximately 3 °C by 2076–2095, relative to the baseline period of 1980–1999, with temperatures in the northern and eastern parts of the country rising by as much as 3.5 °C.[6]
Rain Pattern	Japan experiences the East Asian monsoon. The average annual precipitation varies across the country, reaching 2,481 mm in Naha, 1,590 mm in Tokyo and 905 mm in Sapporo (2020).[3]
Hydrology	The rivers in Japan are short and fast-flowing, with steep gradients. Waterfalls are not uncommon in the mountainous landscape of the country. The longest rivers are the Shinano, Tone and Ishikhari Rivers.[7]

ELECTRICITY SECTOR OVERVIEW

The total installed capacity of Japan equalled 293,897 MW as of March 2020. This total included the installed capacity of thermal power plants at 189,784 MW (65 per cent); hydropower, including pumped storage, at 50,033 MW (17 per cent); nuclear power at 33,083 MW (11 per cent); solar power at 16,522 MW (6 per cent); wind power at 3,951 MW (1 per cent); geothermal energy at 481 MW (0.2 per cent); and other resources at 43 MW (less than 0.1 per cent) (Figure 1).[8]

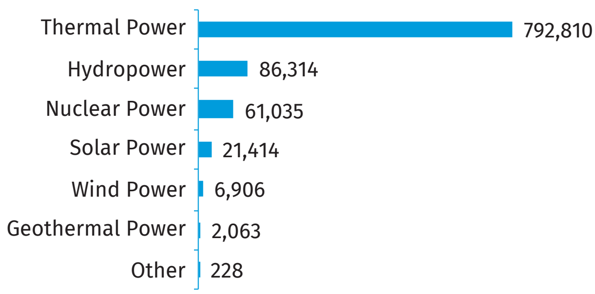
Annual electricity generation in Japan totalled 970,770 GWh between April 2019 and March 2020, with thermal power contributing 792,810 GWh (82 per cent) of the total, hydropower, including pumped storage, contributing 86,314 GWh (9 per cent), nuclear power contributing 61,035 GWh (6 per cent), solar power contributing 21,414 GWh (2 per cent), and wind power, geothermal energy and other resources contributing 6,906 GWh, 2,063 GWh, and 228 GWh, respectively (altogether less than 1 per cent) (Figure 2).

Figure 1. **Installed Electricity Capacity by source in Japan in 2020 (MW)**



Source: METI[8]

Figure 2. **Annual Electricity Generation by source in Japan in 2019–2020 (GWh)**



Source: METI[8]

Note: Data for the period between 1 April 2019 and 31 March 2020.

While the energy mix of Japan is dominated by thermal power, the focus on developing renewable energy resources including small hydropower (SHP), solar power, wind power and geothermal energy has progressively strengthened in recent years. Renewable energy sources including hydropower produced a total of 137,281 GWh between April 2019 and March 2020, accounting for approximately 14 per cent of total electricity generation. Furthermore, technological development and social testing of new energy technologies, such as hydrogen fuel cells, solar sharing with agriculture and smart grid systems, are underway.[8]

In 1995, the Government of Japan started the process of liberalizing the electricity sector, culminating in its full liberalization in April 2016. Following the liberalization, every consumer including households and retail dealers gained the ability to select electric utilities and power producers independently. Additionally, while only 10 power companies operated in the country prior to the liberalization, each serving a designated region, 749 new power producers were able to enter the market by March 2022 as a result of this process. The share of these new producers in the electricity market of Japan is approximately 16 per cent, based on the quantity of power sold.[9,10]

Although there are many newly established electric power companies, the Japanese electricity market is still dominated by 10 major regional power utilities, which form the Federation of Electric Power Companies (FEPC). They include Hokkaido Electric Power, Tohoku Electric Power, Tokyo Electric Power (TEPCO), Chubu Electric Power, Hokuriku Electric Power, Kansai Electric Power, Chugoku Electric power, Shikoku Electric Power, Kyushu Electric power and Okinawa Electric Power.

The institutions regulating the energy market in Japan include:

- Ministry of Economy, Trade and Industry (METI), which has the overall responsibility for energy policy in Japan;
- Agency for Natural Resources and Energy (ANRE) within METI, which is in charge of comprehensive energy policies to ensure strategic energy security, realize an efficient energy supply and promote environment-friendly energy policies;
- Ministry of the Environment, in charge of climate change and air pollution mitigation;
- Ministry of Land, Infrastructure, Transport and Tourism, in charge of energy efficiency and water resource management;
- Ministry of Education, Culture, Sports, Science and Technology, which is in charge of certain areas of energy research and development;
- Electricity and Gas Market Surveillance Commission (EGC), which monitors the electricity, gas and heat markets;
- Japan Fair Trade Commission (JFTC), responsible for monitoring competition in all sectors of the economy, including the electricity and natural gas industries;
- Nuclear Regulation Authority.[11]

Electricity tariffs in Japan are composed of a basic charge based on household size and priced per contract ampere, a usage charge based on used electric power and a surcharge for the promotion of renewable energy. The renewable energy surcharge is determined every year by the Government.

Table 1. **Basic Charges for Electricity per Contract Ampere**

Contract Ampere (A)		*10 A*	*15 A*	*20 A*	*30 A*	*40 A*	*50 A*	*60 A*
Basic charge (standard)	JPY	286	429	572	858	1,144	1,430	1,716
	USD	2.67	4.01	5.35	8.02	10.69	13.36	16.04
Basic charge (TEPCO Aqua Energy 100)	JPY	561	841	1,122	1,683	2,244	2,805	3,366
	USD	5.24	7.86	10.49	15.73	20.97	26.21	31.46

Source: TEPCO,[12] TEPCO[13]

Table 2. **Usage Charges for Electricity per kWh**

Standard (TEPCO)			*TEPCO Aqua Energy 100*		
	JPY/kWh	*USD/kWh*		*JPY/kWh*	*USD/kWh*
up to 120 kWh	19.88	0.19	up to 300 kWh	23.83	0.22
from 120 kWh to 300 kWh	26.48	0.25	above 300 kWh	30.57	0.29
above 300 kWh	30.57	0.29			

Source: TEPCO,[12] TEPCO[13]

Table 3. **Unit Price of the Renewable Electricity Surcharge in 2012–2022.**

Period	*Renewable energy surcharge*	
	JPY/kWh	*USD/kWh*
Aug. 2012 – Mar. 2013	0.22	0.0021
Apr. 2013 – Apr. 2014	0.35	0.0033
May 2014 – Apr. 2015	0.75	0.0070
May 2015 – Apr. 2016	1.58	0.0148
May 2016 – Apr. 2017	2.25	0.0210
May 2017 – Apr. 2018	2.64	0.0247
May 2018 – Apr. 2019	2.90	0.0271
May 2019 – Apr. 2020	2.95	0.0276
May 2020 – Apr. 2021	2.98	0.0279
May 2021 – Apr. 2022	3.36	0.0310

Source: Energy Information Center[14]

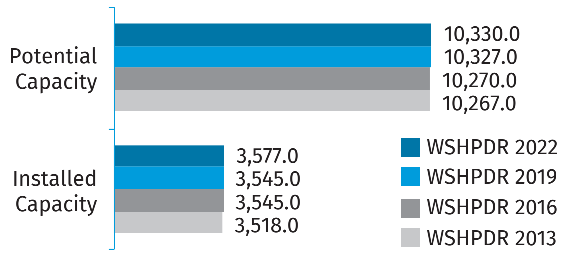
In recent years, a power sales package for renewable electricity has been available on the market. However, sales of this package have been low as all consumers already pay the surcharge for the promotion of renewable energy and the price of electricity is high. Tables 1 and 2 display the costs of regular electricity as well as, for the purposes of comparison, that of the "TEPCO Aqua Energy 100", a package plan aimed at reducing CO_2 emissions, which bundles electricity generated by TEPCO-operated hydropower plants. Table 3 displays the rates of the renewable energy surcharge between August 2012 and April 2022. As can be seen from the table, the surcharge has increased by a factor of 15 over the last decade.

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) generally used in Japan is hydropower plants with an installed capacity of less than 10 MW. However, there is no clear definition and the classification changes depending on the policy and association.

The total installed capacity of SHP in Japan as of March 2019 was 3,577 MW. A further undeveloped potential of 6,753 MW was recognized, of which 62 MW were under construction.[15] Thus, approximately 35 per cent of the available SHP potential has been developed so far. As compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP in Japan has increased by 32 MW, while potential capacity increased by 3 MW (Figure 3).[16] The reasons for the increase in installed capacity include activities undertaken by electricity companies to harness superfluous water from constructed reservoirs and previously undeveloped river flow, local governmental policies promoting the construction of SHP and the activities of non-governmental organizations and agricultural cooperatives at the local level.[17,18]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Japan (MW)**



Sources: METI,[15] *WSHPDR 2013*,[19] *WSHPDR 2016*,[20] *WSHPDR 2019*[16]

The development of hydropower has more than 130 years of history in Japan. In 1891, the Kyoto Keage plant became the first hydropower plant in commercial operation in the country. The plant provided power to general consumers and street trains. After several facility enhancements, the plant remains in operation today.[21] During the period of 1910–1925, nearly 100 hydropower plants were built annually. At the end of 1925, there were over 1,000 hydropower plants in Japan, with plants operating in every part of the country.[22,23]

Studies on national hydropower potential in Japan have been conducted five times: in 1910–1913, 1918–1922, 1937–1941, 1956–1959 and 1980–1985. All of these studies aimed to assess the theoretical, technical and economic potential and viability of hydropower development in the country, as well as installed capacities. In the fifth study, the overall assessment estimated the total national hydropower potential at 46,020 MW. The total installed capacity of existing hydropower plants over 10 MW (including those under construction, and excluding pumped storage plants) is approximately 19,000 MW, or about 41 per cent of the total potential. However, options for further development of large-scale hydropower are limited.[15,22]

A database of all hydropower plants in Japan in commercial use is maintained by the Japan Electric Power Civil Engineering Association (JEPOC). Meanwhile, a separate database maintained by J-watER lists SHP plants under 1 MW, including SHP plants for home use, micro- and pico-hydropower plants. Table 4 provides a list of some recently commissioned SHP plants in Japan, while Table 5 lists some planned and ongoing SHP projects.

Table 4. **List of Selected Operational Small Hydropower Plants in Japan**

Name	*Location*	*Capacity (kW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Matsuguma	Saga	30	20.4	Irrigation channel	Local Community	2020
Mitsuminekawa Honmonji 1	Shizuoka	120	11.2	Run-of-river	Private Company	2019
Mitsuminekawa Honmonji 2	Shizuoka	140	12.2	Run-of-river	Private Company	2019
Shinmiyakawa	Nagano	195	47.2	Run-of-river	Private Company	2019
Okawa Zyosuizyo	Shizuoka	186	85.5	Dam	Local Government	2018
Sakaguchi Zyosuizyo	Nagasaki	49	31.2	Dam	Local Government	2018
Gokayama Dam	Fukuoka	420	89.1	Dam	Prefectural Government	2018
Mitsuse	Saga	4	6.0	Run-of-river	Local Community	2018
Oitake	Kagoshima	30	67.0	Irrigation channel	Private Company	2018
Minakichikun	Kagoshima	45	8.7	Run-of-river	Private Company	2018
Shinmyo	Toyama	700	10.5	Irrigation channel	LID	2018

Name	*Location*	*Capacity (kW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Maebashi Akagiyama	Gunma	236	109.0	Irrigation channel	Local Government, LID	2018
Taguchi	Kagoshima	40	23.0	Irrigation channel	Private Company	2018
Shiraito Step 3	Fukuoka	15	25.2	Check dam	Cooperatives	2018
Taki (rehabilitation)	Iwate	450	25.8	Dam	Prefectural Government	1982/ 2018
Shiraito Step 2	Fukuoka	15	30.0	Run-of-river	Local Government	2017
Tateshina 4	Nagano	145	40.5	Irrigation channel	Private Company	2017
Tokunoshima Dam	Kagoshima	438	42.9	Dam	National Government Land Improvement District (LID)	2017
Kamuro	Yamagata	420	38.3	Dam	Prefectural Government	2017
Ohito	Miyazaki	50	85.0	Irrigation channel	Cooperatives	2017

Source: Watanabe et al.,[17] Alam et al.,[18] JEPOC,[24] J-watER,[25] NIW,[26] Takagi et al.[27]

Table 5. **List of Selected Planned Small Hydropower Projects in Japan**

Name	*Location*	*Capacity (kW)*	*Head (m)*	*Plant type*	*Developer*	*Planned launch year*	*Development stage*
Kuroki kawa	Fukuoka	12	7.0	Run off river type	Private Company	2021	Installation stage
Kawagoe	Kagoshima	15	18.1	Run off river type	Private Company	2021	Installation stage
Undecided	Kumamoto	50	32.5	Irrigation channel	Local Community	2021	Applied for grid connection certificate
Iki-Sagawa	Saga	200	67.0	Run off river type	Private Company	2022	Application preparation
Minamidani	Shimane	50	71.2	N/A	Private Company	2022–2023	Planned
Aburai	Shimane	200	183.1	N/A	Private Company	2022–2023	Planned

Source: Fujimoto, T.[28]

The Ministry of the Environment of Japan developed an online system known as the Renewable Energy Potential System (REPOS), for the purpose of identifying and cataloguing potential renewable energy sites, including SHP. Listed potential SHP sites include existing irrigation channels and other water facilities.[29] Table 6 displays some examples of potential SHP sites available for development in the country.

Table 6. **List of Selected Small Hydropower Sites Available for Development**

Name	*Location*	*Capacity (kW)*	*Head (m)*	*Type of site*
Morotsuka Dam	Miyazaki	30.0	34.0	New
Taguchi B	Kagoshima	30.0	12.0	New
Taguchi C	Kagoshima	50.0	17.0	New
Iwayagawa	Saga	49.9	25.0	New
Yokotake Dam	Saga	49.9	23.4	New

Source: Fujimoto, T.[28]

According to the feed-in tariff (FIT) mechanism of Japan introduced in July 2012, the purchase price of hydropower varies depending on scale: less than 200 kW, from 200 kW to 1 MW and from 1 MW to 30 MW. Furthermore, in 2019 these categories were amended, with the 1 MW to 30 MW category being subdivided into categories from 1 MW to 5 MW and from 5 MW to 30 MW, with different purchase prices set for each category. Therefore, the price of medium and small-scale hydropower in the FIT system was divided into four levels. The tariffs for hydropower in April 2019–March 2020 were as follows:

- 5 MW to 30 MW: 20 JPY/kWh (0.19 USD/kWh);
- 1 MW to 5 MW: 27 JPY/kWh (0.25 USD/kWh);
- 200 kW to 1 MW: 29 JPY/kWh (0.27 USD/kWh);
- under 200 kW: 34 JPY/kWh (0.32 USD/kWh).[30]

The total capacity of medium and small-scale hydropower (less than 30 MW) certified under the FIT mechanism during the period of April 2019–March 2020 was 1,331 MW. The cumulative amount of purchased electricity under the system in the same period was 16,579 GWh and the total purchase price was JPY 4,390.8 billion (USD 41.6 billion).[31]

Since the publication of *WSHPDR 2019*, the number of SHP plants certified under the FIT mechanism has increased even though the actual installed capacities have barely changed. This is due to the fact that in many cases, FIT certification is approved for existing plants that have undergone renewal or rehabilitation. Local authorities often provide support for renewal and rehabilitation of deteriorated and discarded old SHP plants, as well as implementation of SHP on check dams and on dams and canals used for irrigation. As such, 'new' SHP potential can be often established using existing infrastructure.

RENEWABLE ENERGY POLICY

Since the 1970s and 1980s, the national energy and energy security policies of Japan have been aimed at reducing the dependency of Japan on petroleum, prompting the development of alternative energy sources and technologies. Alternative energy sources include new energy sources such as liquefied natural gas (LNG), nuclear power and improved coal technologies, as well as renewable energy sources.[22]

In 2008, the New Energy Law was put into effect in order to establish special measures for promoting the use of new energy. The concept of new energy was also redefined as including solar energy generation, wind power generation, biomass generation, biomass thermal generation, biomass fuel production, thermal energy conversion, geothermal power generation (binary system) and SHP (under 1MW).[22]

The Great East Japan Earthquake and the accident at the TEPCO Fukushima Daiichi Nuclear Power Plant became a major turning point in the energy policy of Japan. In order to facilitate the shift away from nuclear power as well as to reduce dependence on fossil fuels, the FIT framework was developed and introduced in July 2012. Tariffs are set for each renewable energy category (wind, solar, geothermal, hydropower, biomass) and are revised annually based on the degree of circulation and market conditions for each renewable energy source. The FIT requires electric utility companies to purchase electricity produced from renewable energy sources at a higher price than that from conventional fossil fuel-based energy. The purchase period set for tariffs is 20 years. FIT is designed so that authorities at all levels have a mandate to promote renewable energy.

The Fifth Energy Basic Plan, adopted in July 2018, again defined the rapid development of renewable energy to the status of the primary source of energy generation to be the key target.[32] To achieve this target, a part of the FIT framework will be modified as a feed-in premium (FIP), applied to large-scale and industrial solar power and wind power (excluding offshore wind power). Starting from April 2021, these two energy sources, go into the electric market independently with a competitive price based on the FIP.

SHP development in Japan has lagged behind solar and wind power and while the FIT covers plants of up to 30 MW, large-scale hydropower projects are no longer pursued in Japan. In recent years, small- and micro-scale hydropower (under 1 MW) is mainly being installed in stages by local communities as part of various community development schemes. Due to the gradual and community-driven nature of SHP development in Japan, innovations and cost reduction processes are still in progress.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The key law promoting SHP development in Japan is Law No. 358 from 29 December 1952, most recently amended by Law No. 37 from 2 May 2011, otherwise known as the "Act on the Promotion of Introducing Electricity into Farming and Fishing Villages". The key aims of the law as originally conceived, outlined in Article 1, are the electrification of remote fishing and farming communities undersupplied by electricity, including those on remote islands, for the purpose of improving economic productivity as well as the general standard of living in these areas. The law outlines a crediting scheme for SHP projects by the Japan Finance Corporation and government subsidies and defines the operating entities taking advantage of this support as non-profit community organizations composed of individuals otherwise engaged in local industries such as fishing, farming and forestry.[33] The support schemes and regulations established by this law have ensured that historically, and until the present day, SHP development in Japan has been spearheaded by community efforts and will likely continue to be in the future.

The law and the history of SHP development in Japan flowing out of its implementation has important implications for future SHP initiatives. Firstly, it is important to note that SHP in Japan is mainly a community-based resource and communities must remain the primary controlling and operating actor. Consensus building and realignments of water rights with water users, circulation of expertise, as well as the development of rules in relation to water resource management based on public interest are vital.[34] Any development plans must consider not only the potential of the water resource in question, but also the natural and social environment and the history of past space use.[22,23] Finally, the issue of insufficient human resources for the coordination, planning, construction and maintenance must be taken into account, with focus on creating a framework for sustainable, stable communities.[35]

COST OF SMALL HYDROPOWER DEVELOPMENT

Table 7 shows the cost of the 30 kW Oitake SHP plant in Kagoshima, which was previously analyzed in a case study included in the *WSHDPR 2019*.[17] The total cost of the plant was JPY 74,076,000 (USD 692,299). Of this total, the cost of construction was approximately JPY 50,000,000 (USD 4,673) and therefore, the installation cost per kW, in this case, was approximately 1,666,667 JPY/kW (15,576 USD/kW).

Table 7. **Cost Breakdown of 30kW Oitake Small Hydropower Plant in Kagoshima**

Item name	*Unit cost (JPY (USD))*	*Number of units*	*Total price (JPY (USD))*
Construction costs			
Mechanical equipment cost		1	
Electrical equipment cost	34,000,000 (310,049)	1	34,000,000 (310,049)
Control panel cost		1	
IOT cost		1	
Civil engineering cost	12,000,000 (109,429)	1	12,000,000 (109,429)
PJ Management	2,000,000 (18,238)	1	2,000,000 (18,238)
Installation & commissioning	2,000,000 (18,238)	1	2,000,000 (18,238)
SUBTOTAL			**50,000,000 (455,955)**
Running costs			
Equipment replacement cost in 20 years	5,684,000 (51,833)	1	5,684,000 (51,833)
Inspection costs:			
Yearly inspection cost	258,000 (2,353)	16	4,128,000 (37,644)
Quinquennial inspection cost	466,000 (4,249)	4	1,864,000 (16,998)
Yearly personnel inspection cost	-	20	-
Water uses cost in 20 years	-	20	-
Land uses cost in 20 years	120,000 (1,094)	20	2,400,000 (21,886)
Miscellaneous costs: management cost by the owner, electrical security cost, etc.	500,000 (4,560)	20	10,000,000 (91,191)
SUBTOTAL			**24,076,000 (219,551)**
TOTAL			**74,076,000 (675,506)**

Source: NIW,[26] Fujimoto, T.[28]

EFFECT OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

In general, the strong commitment of Japan to renewable energy sources in the face of climate change is likely to benefit SHP. However, the sector is also likely to be affected by increased natural hazards over the coming decades, in particular, damage to SHP facilities by landslides and debris flows triggered by intense rainfall that are very common in Japan. According to climate predictions, the incidence of heavy rainfall is likely to increase by 10–25 per cent by the year 2100, relative to the end of the 20th century.[4] Additionally, the generation of suspended sediment in the rivers of Japan is expected to increase by anywhere from 8 per cent to 24 per cent by the 2090s relative to the 1990s.[36] This is likely to increase the operation and maintenance costs of SHP plants.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The SHP sector in Japan is complex, with a long history of development that, on the one hand, creates specific obstacles to the propagation of SHP, but, on the other hand, provides several advantages. Obstacles to SHP development in Japan can be summarized in the following points:

- SHP is primarily community-based and extensive engagement and consultation with the local community, as well as the direct involvement of community-based organizations, is necessary in the case of most projects;
- Small communities in Japan often have insufficient human resources for implementing SHP projects, therefore, the long-term viability of any SHP project ultimately depends on the sustainability of the host community;
- Difficulties with building a wholesale electricity market and implementing a power system reform;
- Difficulties with researching and developing independent community grid systems;
- Lack of clarity on the details of electricity market liberalization, including who will bear the costs of system connection and wide-area maintenance and how to formulate disclosure rules for related information;
- Recent policy focus on the development of wind and solar power.
- On the other hand, several enabling factors for SHP development exist. These include:
- Abundant remaining hydropower potential that has been well-mapped but is generally not suited for large-scale hydropower;
- A long history of SHP development and a well-established framework for community engagement and operation of SHP projects;
- Established financial support schemes in the form of loans, subsidies and FITs.

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Mongolia

Ayurzana Badarch, Mongolian University of Science and Technology; and Gendensuren Yondongombo, Monnationenergy NGO

KEY FACTS

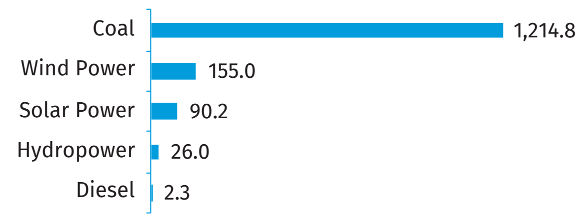
Population	3,296,866 (2019)[1]
Area	1,564,120 km^2
Topography	Mongolia is a landlocked country located on a vast plateau with an average elevation of 914–1,524 metres above sea level. The southern, northern and western regions are mountainous with an average elevation of 1,580 metres. The plateau consists of arid and semi-arid pasture lands and the Gobi Desert, while the northern mountain ranges form the southern front of Siberia. The eastern side of the Altai Mountains dominates in the west of the country. There also lies the highest peak in Mongolia, Huyten Orgil, at 4,374 metres above sea level.[2]
Climate	Due to being located far from the sea, Mongolia has a sharply continental climate. The temperature varies not only across seasons, but also during the day.[3] The climate in the northern and western parts of the country is very cold, while in the eastern and southern parts it is cold only in winter. The average annual temperature is approximately 0.2 °C.[4] The ground freezes down to 3 metres in winter and the total number of cold days is 160–220 a year.[5]
Climate Change	The average annual temperature increased by 2.14 °C over the last 70 years due to climate change.[5] Although the average annual precipitation rate has not significantly changed, local and temporal changes in the rain pattern have been observed, including sudden heavy rains and prolonged periods of drought.[4,6]
Rain Pattern	Precipitation in the country is defined by the geographical and topographical conditions, such as lakes and mountains. In the north, annual precipitation averages 250–390 mm, while it is only approximately 70–150 mm in the south. Most precipitation falls in the form of rain in the warm months and less in the form of snow in winter.[6]
Hydrology	Mongolia is situated on three international river basins: the Arctic Ocean basin (AOB), the Pacific Ocean basin (POB) and the Central Asian internal drainage basin (CAIDB). The headwaters of rivers in these three basins arise in the three main mountainous regions: Altai, Khangai and Khentey. The rivers starting from the Khangai Mountains in the AOB and from the Khentey Mountains in the POB flow northwards and eastwards, respectively. Major rivers in the CAIDB end as lakes or become dry channels. All rivers in Mongolia are covered with 1–2 metres of ice in winter. The rivers are fed by permafrost, glaciers, snow and springs fed by precipitation. Based on historical data, annual water runoff of all rivers in Mongolia is estimated at 34.6 km^3.[7]

ELECTRICITY SECTOR OVERVIEW

The electricity sector of Mongolia consists of five independent electric systems: the Central Regional Integrated Power Grid (CRIPG), which has most sources and consumers; Western Regional Integrated Power Grid (WRIPG); Eastern Regional Integrated Power Grid (ERIPG); Altai-Uliastai Integrated Power Grid (AUIPG) and Southern Energy System (SES). Mongolia consumes approximately 8.5 TWh of electricity annually, with roughly 80 per cent of consumption coming from local sources and 20 per cent being imported from Russia and China. Most of the imported electricity comes from China to the Oyu Tolgoi mine. The central and western regions import approximately 300 GWh of electricity annually from Russia.[8]

As of 2019, the total installed capacity of Mongolia stood at 1,309.5 MW, with renewable sources accounting for 18 per cent of the total.[8] In 2020, the country's installed capacity reached 1,488.3 MW (Figure 1).[9]

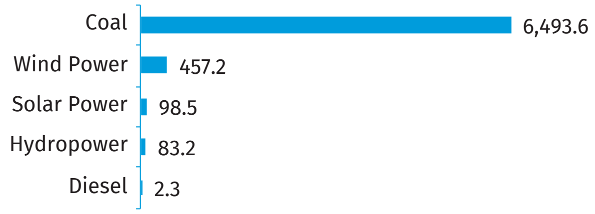
Figure 1. **Installed Electricity Capacity by Source in Mongolia in 2020 (MW)**



Source: MOE[9]

In 2020, a total of 7,134.9 GWh of electricity was generated in the country.[9] Ninety-one per cent of electricity production came from coal-fired combined heat and power (CHP) plants, almost 9 per cent was produced by renewable energy sources and the remaining 0.03 per cent came from local diesel generators (Figure 2).

Figure 2. **Annual Electricity Generation by Source in Mongolia in 2020 (GWh)**



Source: MOE[9]

According to the National Statistics Office, the number of households supplied with electricity in the country increased from 548,517 in 2010 to 732,494 in 2020. At the same time, the number of households without electricity decreased from 23,610 in 2010 to 4,817 in 2020.[10]

The energy and electricity sector of Mongolia is governed by the Ministry of Energy (MOE) and regulated by the Law on Energy, Law on Energy Conservation, Law on Renewable Energy and other related regulations and bylaws. The role of MOE is to provide accurate, timely and prompt consultation as well as an all-round support for the implementation of the Government's plans to improve the energy sector. According to the Energy Law, the Energy Regulatory Commission (ERC) is responsible for regulating energy production, transmission, distribution, dispatching and supply.[11] The objectives of ERC include ensuring conditions for fair competition among sector licensees and protecting the rights of both consumers and licensees. Another important agency is the National Renewable Energy Centre, which is responsible for promoting renewable energy technologies and for supporting renewable energy research projects nationwide.

The Government of Mongolia has singled out nine priority areas for action in the energy sector from 2020 to 2024. The most important targets are security of the energy system, support for new sources and renewable energy production.[12]

Electricity tariffs in Mongolia are not uniform and vary depending on the grid, consumer type and type of the electricity metre installed. Electricity tariffs are set by ERC (Table 1).[11] In September 2002, ERC introduced the Single Buyer Model for the CRIPG. The single buyer is the state-owned Central Regional Electricity Transmission Network (CRETN), which purchases electricity from power sources, including additional imports, and sells it to 11 electricity distribution companies. Following a successful spot market trial in 2005, in 2006 the National Dispatching Centre was selected to act as the spot market operator. The spot market includes five co-generators and is operated based on real-time consumption and scheduled electricity rate difference. In 2007, ERC also started an auction market, where the incremental electricity demand is auctioned off among generation licensees for the best reduced tariff percentage. The auction market is also operated by the National Dispatching Centre.

Table 1. **Average Electricity Tariffs for Residential and Commercial Consumers in Mongolia in 2021**

Electric grid	*Tariff in MNT/kWh (USD/kWh)*
CRIPG	168.8 (0.059)
AUIPG	151.6 (0.053)
WRIPG	173.1 (0.061)

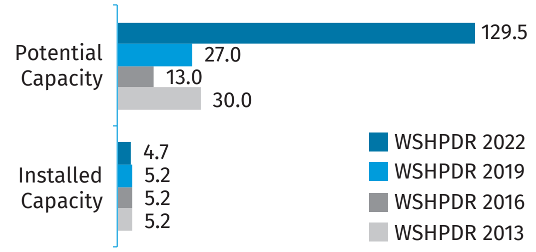
Source: ERC[13]

SMALL HYDROPOWER SECTOR OVERVIEW

Mongolia has no official definition of small hydropower (SHP). However, the international definition of up to 10 MW has been in use.

As of 2021, there were 10 SHP plants with a total installed capacity of 4.7 MW (Table 2).[14] The total SHP potential of Mongolia remains unknown, however, based on data on planned projects and data reported in literature, it is possible to conclude that there is at least 129.5 MW of potential capacity available.[15,16,17,18] This total includes a number of sites with a combined potential of 74.4 MW that were identified in investigations carried out by former Soviet and Mongolian institutes.[17] Furthermore, in 2008, based on a field survey and existing hydrological data, the National Renewable Energy Centre of Mongolia identified an additional potential of 20 MW from another 17 sites that had not been reported elsewhere before.[18] Finally, the potential estimate total also includes a number of planned SHP projects, which do not coincide with the mentioned studies (Table 3). Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed SHP capacity of Mongolia has slightly decreased (from 5.2 MW reported in the previous edition) due to the exclusion from the total of the destroyed 530 kW Kharkhorin plant. On the contrary, the potential capacity estimate increased due to access to more accurate data (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Mongolia (MW)**



Source: CIF,[14] ХИ & УББСХТ,[15] Badarch & Yondongombo,[16] Hydroplan Group,[17] Boldbaatar,[18] *WSHPDR 2013*,[19] *WSHPDR 2016*,[20] *WSHPDR 2019*[21]

Five of the existing SHP plants — Galuutain, Hunguin, Tosontsengel, Bogd and Guulin — operate only in the summer time. The other five have been abandoned or stopped operating since the supplier has been connected to the grid. The total annual production of SHP plants in Mongolia is approximately 5.4 GWh per year, of which 4.9 GWh is generated annually by the SHP plants in active operation.[22] The Erdenebulgan, Uyench, Munkh-khairkhan, Mankhan and Undurkhangai SHP plants would be able to operate only after a major restoration.

Table 2. **List of Existing Small Hydropower Plants in Mongolia**

Plant	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Galuutain	Galuutain River, Zawkhan	0.11	1.2	Run-of-river	AUIPG	2008
Hunguin	Hungui River, Zawkhan	0.15	7.0	Run-of-river	AUIPG	2008
Tosontsengel	Ider River, Zawkhan	0.38	3.3	Run-of-river	AUIPG	2006
Erdenebulgan	Egiin River, Khuwsgul	0.20	–	Diversion	CRIPG	2006
Bogd	Uliastai River, Zawkhan	2.00	35.0	Diversion	AUIPG	2005
Uyench	Uyench River, Khovd	0.96	14.0	Diversion	WRIPG	2005
Munkh-khairkhan	Tsenkher River, Khovd	0.15	7.5	Diversion	WRIPG	2003
Guulin	Zawkhan River, Govi-Altai	0.40	40.0	Diversion	AUIPG	1998
Mankhan	Tugrug River, Khovd	0.15	13.8	Diversion	WRIPG	1998
Undurkhangai	Chigj River, Uvs	0.20	1.9	Diversion	WRIPG	1989
Total		**4.67**				

Source: CIF,[14] Badarch & Yondongombo[16]

The theoretical and technical hydropower potential of the Mongolian rivers was first determined in 1976 as part of a scheme on integrated use and protection of water resources. The total theoretical hydropower potential is estimated at 50,513 GWh, of which 15,200 GWh is the technical potential. In 1994, the Ministry of Nature updated the theoretical hydropower potential to 56,200 GWh, with 36,700 GWh of potential identified in POB, 4,907 GWh in AOB and 14,592 GWh in CAIDB.[7] The theoretical and technical hydropower potential estimates need to be updated clearly defining the exploitable small, medium and large hydropower potentials. As of 2021, there was no ongoing SHP construction work in Mongolia.

A number of hydropower projects of various capacities, located on all big rivers across Mongolia have been proposed by both private and governmental entities. The projects considered feasible are mainly located in western Mongolia, where the high head can be utilized instead of the discharge. The Ministry of Nature, Environment and Tourism of Mongolia has selected 33 potential hydropower projects, including small- and large-scale ones, to be implemented until 2040 with the help of local engineering firms under the project called Blue Horse.[15] Some of the SHP sites indicated in the Blue Horse project as well as previous potential proposals are listed in Table 3.

Table 3. **List of Selected Planned Small Hydropower Projects in Mongolia**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Developer*	*Planned launch year*	*Development stage*
Bulagt Uul	Ongi River, Uvurkhangai	4.0	16	Reservoir	GHP LTD	2021–2025	Feasibility study
Baidrag	Baidrag River	8.0	54	Reservoir	Monhydro construction LTD	2026–2030	Feasibility study
Eg-Khengertei	Egiin River	6.0	30	Diversion	Hydro Engineerging LTD	2035–2040	Pre-feasibility study
Teeliin	Teel River	2.2	10	Reservoir	Hydro Engineerging LTD	2035–2040	Pre-feasibility study
Ulgii	Khovd River	9.7	20	Reservoir	Usny Erchim LTD	Undefined	Feasibility study

Source: ХИ & УББСХТ,[15] Badarch & Yondongomb[16]

SHP in Mongolia is generally understood as a seasonal source of electricity, since the existing SHP plants cannot operate during the cold winters, when electricity demand is the highest. Instead, SHP is regarded as a suitable source of electricity for agricultural and industrial purposes in the summer time.

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

Two SHP projects available for investment are the Baidrag and Bulagt-Uul sites (Table 3). Both projects are developed by private companies and are open for investment. The Baidag site was first identified in 1981 for the development of a large-scale irrigation system in the Bayankhongor Province. In 1985, the feasibility study and technical drawings for the Baidrag SHP project were prepared. Due to political changes in 1990, the project was no longer supported by the Government. In 2010, the national consulting firm named Monhydro construction LTD updated the feasibility study through a detailed investigation of the site and hydrology.

RENEWABLE ENERGY POLICY

Within the framework of national laws related to water and energy, a number of national programmes have been implemented. For example, the national renewable energy programme started in 2005 was completed in 2020 with adequate outcomes achieved for all types of renewable energy sources. The Galuutain, Hunguin, Tosontsengel and Erdenebulgan SHP plants were developed as part of this programme. The national water programme addressing hydropower development in terms of water resources development also expired in 2020. It, however, demonstrated poor accomplishment in respect to SHP development due to a number of reasons, including the poor institutional structure for programme implementation, lack of follow-up regulations and investment and unclear action strategy for SHP development.

In 2015, the parliament of Mongolia, the State Great Khural, approved the energy policy until 2030 with two stages of implementation.[23] Under this policy, the share of hydropower, including SHP, could reach 10 per cent of the country's total installed capacity in the first stage by 2030.[24] The follow-up government resolution from 2018 on a six-year programme readdressed some goals, including hydropower development not realized in the past.[25] The resolution promoted the development of SPH that can operate continuously throughout the year. However, the policy does not address climate change adaptation and CO_2 emission reduction. In the same year, the Government of Mongolia put forward another energy programme focusing on energy conservation, which aims to cut 620 ktCO_2 emissions by curbing wasteful consumption of electricity, implementing new technology and improving the legal environment.[26]

As of 2021, hydropower development, including SHP plans, which are not defined separately, has been identified in the country's sustainable development goals and long-term national development plans.[27] The Blue Horse project is included in the Vision 2050 development policy.

The Law on Renewable Energy was first introduced in 2007 and successively amended in 2015 and 2019. The revised law redefines the tariffs for solar and wind power connected to the grid as well as regulates technical issues and price competitiveness or tendering for the implementation of renewable energy projects. It also stipulates that the responsible company must be financially viable to ensure a successful implementation of the project. In addition, a system of prices, tariffs and incentives was established in response to the increasing use of low-capacity renewable energy sources from households to the industrial level in recent years.[28] The Government expects that the revised law will help increase the share of renewable energy sources in the country's energy mix to 30 per cent, including 10 per cent for hydropower. Under this law, as of 2019, ERC had issued licenses for a total of 35 legal entities to construct renewable energy projects with a combined capacity of 1,379.8 MW, including 3 legal entities with 217.4 MW of hydropower capacity.[8]

Another goal of the Renewable Energy Law is to reduce costs and create a real market price for the technologies, with the changes in solar and wind power prices and tariffs making it possible not to increase the renewable energy support tariffs. According to the law, the tariff range given in Table 4 should be used as a reference for ERC to define the tariffs for the commissioned projects.[28]

Table 4. **Feed-in Tariffs for Renewable Energy Sources in Mongolia**

Electricity source	*Hydropower up to 5 MW*	*Hydropower above 5 MW*	*Wind power*	*Solar power*
Tariff range (USD/kWh)	0.045–0.060	to be defined by ERC based on feasibility study	up to 0.085	up to 0.120

Source: State Great Khural[28]

Comparing the electricity tariffs in Table 1 and the feed-in tariffs (FITs) in Table 4, it can be seen that wind and solar power generators sell electricity to the grid at a high price. The compensating mechanism for the difference between the FITs and the electricity tariffs is defined in the Law on Renewable Energy.

Consulting engineers and practitioners in the hydropower sector criticize the uneven tariff range depending on the energy source as defined in the Law on Renewable Energy. It is suggested that foreign investors into SHP projects will not be interested because of this tariff range. The relatively high FITs for wind and solar power create a favourable environment for these sources and shorten the payback period for such projects in comparison to SHP.

There are no specific SHP legislation or regulations in Mongolia.

COST OF SMALL HYDROPOWER DEVELOPMENT

According to one economic assessment, hydropower projects in Mongolia with an investment of up to 5,000 USD/kW can be considered profitable.[29] In line with this, the majority of previously commissioned projects can be evaluated as profitable, while the planned SHP projects listed in Table 3 can be considered low-profit.[15] The exact cost breakdown of these projects has not been made accessible to the public.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER DEVELOPMENT

According to the Law on Renewable Energy and the resolution of the State Commission for the State Great Khural, every electricity consumer is required to pay the so-called renewable energy support tariff to compensate for the tariff difference between the conventional CHP generation and renewable energy generation (specifically, solar and wind power). This renewable energy support tariff is one of the financial mechanisms available for SHP projects in Mongolia.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

It has been repeatedly noted that climate change has negatively impacted the water resources in Mongolia.[30] The rivers in the country are sensitive to small changes in temperature, precipitation and land use. In this regard, the diversion type of SHP can be affected by the climate crisis more than conventional types of SHP plants. As an example, the Uvurkhangai SHP plant on the Chigj River was abandoned because of a decline in the river flow, leading to an insufficient water level for running the turbine.[7] No measures have been taken to adapt to the changed conditions after the plant was connected to the electric grid and the technical worker left for a full-time job.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There is a need for SHP development all over Mongolia, especially in rural areas. However, a number of barriers pertain and hinder development, including the following:

- The low FITs for hydropower remain the biggest barrier for investment in SHP projects in Mongolia. The demands to increase or equalize the tariffs submitted by relevant parties during the process of law amendment were not supported.
- The lack of specific regulations, legislation and policy on SHP creates ambiguities for SHP projects in all stages of approval.
- In winter, small- to medium-sized rivers freeze over, which creates seasonal difficulties for SHP operation (ice, declined discharge in winter and geomorphological changes in river channels) and makes projects less profitable both in the development stage and during operation. The technical possibility of operating SHP continuously during the whole year should be studied in the planning phase. The lessons learned from diversion type SHP projects in the country, such as the Uwurkhangai and Munkhhairkhan plants, show that the plants located on rivers vulnerable to the climate crisis must have a reservoir to ensure enough water resources when the river discharge is declined.
- Political and social responses to the environmental impact of hydropower is strong in Mongolia. It is important to improve public awareness about SHP and ensure that projects are judged based on the environmental impact assessment and mitigation measures.
- The lack of human resources in the development and operation of SHP projects is crucial as the abandonment of plants happens mainly because of the lack of proper maintenance and skilled employees. For SHP plants with seasonal operation, the unemployment period for the employees must also be regulated.

In spite of the above barriers, there are also a number of enabling factors for SHP development in the country, particularly the existing institutional structure:

- The State Great Khural is responsible for amending or enacting a law to create favourable legislation for SHP development, including setting reasonable FITs for hydropower development, especially SHP, and, thus, incentivizing investment.
- Government agencies, such as the Renewable Energy Centre and the Water Agency, are responsible for initiating supportive regulations and policy for SHP. They resolve issues related to investment and development as well as incorporate private enterprises for the approval of the Government and the State Great Khural.

It is suggested that in order to facilitate SHP development in the country, the FITs for hydropower should be increased. Furthermore, the abandoned SHP plants could be restored and the share of electricity production should be regulated to utilize SHP in summer. In this regard, management of human resources should be addressed. Finally, research institutions with government support should carry out research on the SHP potential and operation challenges, including capacity building.

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The Republic of Korea

Seung Oh Lee and Dong Hyun Kim, School of Urban and Civil Engineering, Hongik University

KEY FACTS

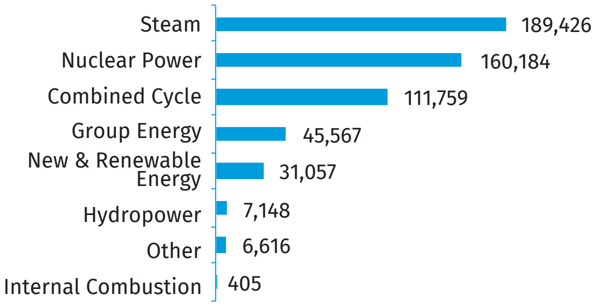
Population	51,829,136 (2020)[1]
Area	100,378 km^2 [2]
Topography	The Korean Peninsula, surrounded by sea on three sides, has a relatively long coastline. Although the altitude is not high, the peninsula has a complex geological nature, with a steep slope and a diverse topography. The average altitude of the Korean Peninsula is 448 metres. The elevation of major mountains, such as Mount Geumgang, Mount Seorak and Mount Odae, is 1,500–1,700 metres above sea level. The highest elevation is Mount Hallasan, located on Jeju Island, the southernmost point of the Korean Peninsula, at 1,947 metres above sea level. The average slope is approximately 5.7° and 77 per cent of mountains are below 400 metres above the sea level.[2]
Climate	The Republic of Korea is located in the mid-latitude temperate climate zone. Winters are cold and dry due to the influence of the continental anticyclone, while summers are hot due to the high temperature and humidity of the North Pacific anticyclone. In spring and autumn there are many sunny and dry days because of the influence of migratory anticyclones. The average annual temperature is 10–15 °C, except for the central mountainous areas and islands. The hottest month is August when temperatures reach 23–26 °C, while the coldest month is January when temperatures range between -6 °C and 3 °C.[3]
Climate Change	Average annual temperature increase for every 10 years of the 20th century amounted to 0.18 °C. The future temperature increase projections in the country match the global average, while the projected increase in precipitation is above the global average. It is expected that extreme weather events will become more frequent.[4,5]
Rain Pattern	Average annual precipitation in the country over the 2010–2019 period was 1,263 mm. There is a large variation in precipitation according to the region and watershed. In the central region, annual precipitation ranges between 1,200 mm and 1,500 mm, in the southern region it is 1,000–1,800 mm. In Jeju Island precipitation ranges between 1,500 mm and 1,900 mm. Seasonally, 50–60 per cent of the annual precipitation torrentially falls during the flood season, which lasts from June to September.[6]
Hydrology	There are five major river basins: the Han River basin, the Geum River basin, the Yeongsan River basin and the Seomjin River basin draining into the Yellow Sea, and the Nakdong River basin draining into the Sea of Japan. Due to the predominantly mountainous terrain of the country, rivers have steep slopes. As a result, during the flood season water flows out very rapidly. On the other hand, during the dry season the amount of runoff is small. As a result, the coefficient of flow rate variation is approximately 90–270. The total amount of water resources in the country is estimated at 132.3 billion m^3/year and the average available water resources are 37.2 billion m^3/year, which is only 28 per cent of the total, with the rest lost due to evapotranspiration and other factors.[7]

ELECTRICITY SECTOR OVERVIEW

In 2020, the total installed capacity of the Republic of Korea was 133,392 MW, of which public utilities accounted for 129,191 MW, or almost 97 per cent. Hydropower accounted for approximately 5 per cent of total installed capacity, or 6,506 MW. New and renewable energy (excluding hydropower) accounted for 18,739 MW, or almost 15 per cent of the total.[8] New and renewable energy in the Republic of Korea is defined as hydropower, including small-scale hydropower, solar power, wind power, bioenergy, marine energy, fuel cell and integrated gasification combined cycle (IGCC).

Annual electricity generation in 2020 totalled approximately 552,160 GWh, with 99.7 per cent, or 550,486 GWh, produced by public utilities. Of the total, steam power plants generated the largest share at over 34 per cent, while hydropower accounted for slightly more than 1 per cent, or 7,148 GWh. New and renewable energy (excluding hydropower) accounted for 31,057 GWh, or less than 6 per cent of total electricity generation (Figure 1).[8]

Figure 1. **Annual Electricity Generation by Source in the Republic of Korea in 2020 (GWh)**



Source: KEPCO[8]

Four administrative districts accounted for approximately 60 per cent of total electricity generation in 2020: Chungnam (21 per cent), Gyeongbuk (16 per cent), Gyeonggi (13 per cent) and Incheon (1 per cent). The leading administrative district in terms of new and renewable energy are Jeonnam, Jeonbuk, Chungna and Gyeongbuk, where approximately 57 per cent of total solar power capacity is located. In terms of hydropower, including small-scale plants, the Gangwon province, with its mountainous terrain and high head, produces the largest amount of electricity, with 1,062 GWh generated in 2020.[8]

Electricity consumption in 2019 totalled 520.5 TWh. The rate of electricity consumption growth reached almost 4 per cent in 2018 compared to the previous year, but in 2019 it decreased to 1 per cent due to mild and cooler weather in winter and summer and the resulting lower demand for heating and cooling.[9] Overall, the electricity consumption trend is being majorly impacted by the recent increase in temperature variability.

After the corporate restructuring in 2001, Korea Electric Power Corporation (KEPCO) was split into six subsidiaries. They now compete with other public companies such as K-water and private companies. The share of private companies in the market increased from 13 per cent in 2009 to 33 per cent in 2019. The installed capacity of KEPCO's six subsidiaries was 83,854 MW in 2020, accounting for 63 per cent of the total. In addition, they accounted for approximately 75 per cent (394,522 GWh) of total electricity generation the same year.[8]

The electricity policy in Korea faced the need for an overall inspection and supplementary measures aimed at ensuring a stable supply and demand of electricity were implemented following the power outage in September 2011. As a result, the sector shifted from the traditional policy focused on expanding supply to a creative and eco-friendly policy focused on demand management.

According to the 9th Basic Plan for Electricity Supply and Demand, it is planned to continuously expand the new and renewable energy generating capacity until 2034 to reach a 30–35 per cent share in the mix by 2040.[10] To accelerate investment in new and renewable energy for the transition to a low-carbon economy and society, the target for solar and wind power was raised from the 12.7 GW to be reached in 2019 to 42.7 GW to be reached by 2025. In addition, in accordance with the 3rd Energy Basic Plan (2019), Renewable Energy Act revision (2019) and the Green New Deal plan (2020), it is planned to reach a total of 77.8 GW of new and renewable energy capacity by 2034 (Table 1).[11]

Table 1. **Planned New and Renewable Energy Capacity by Source in the Republic of Korea by 2034 (MW)**

Category	*Solar power*	*Wind power*	*Hydropower**	*Marine power*	*Bioenergy*	*Fuel cell*	*IGCC*	*Total*
Rated capacity (MW)	45,594	24,874	2,085	256	1,410	3,200	346	77,764
Peak contribution (%)	13.9	3.1	21.6	1.1	44.7	67.7	60.0	–
Capacity factor (MW)	6,338	771	450	3	824	2,166	208	10,760

Source: MTIE[10]

Note: *Small hydropower accounts for approximately 23 per cent.

The Korea Power Exchange (KPX) is in charge of the operation of the electricity market in the country and is responsible for such tasks as pricing and settlement to ensure fair and transparent electricity trade between power generation and sales operators.

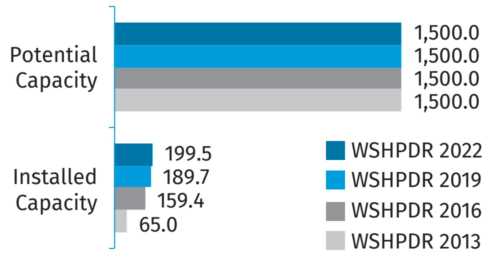
Electricity tariffs in the Republic of Korea are based on a differentiated pricing system according to the purpose of electricity usage: residential, educational, industrial, agricultural, street lighting, public and service, and midnight use. In December 2020, the Ministry of Trade, Energy and Industry (MTIE) and KEPCO announced plans to reform the electricity tariff system, aiming to establish a stronger link between cost fluctuation factors and electricity tariffs, while separately reporting climate and environmental costs. In 2021, an improved residential tariff system was put in place with a provision of financial support for underprivileged consumers. In addition, a seasonal and time-specific differentiated tariff system, similar to the one applied to industrial tariffs, was introduced for residential tariffs. In 2021, residential tariffs ranged from 88.3 KRW/kWh (0.068 USD/kWh) to 285.4 KRW/kWh (0.220 USD/kWh).[12]

SMALL HYDROPOWER SECTOR OVERVIEW

Previously, in accordance with the Alternative Energy Development and Utilization and Supply Promotion Act (1987), hydropower plants with capacity of less than 3 MW were classified as small hydropower (SHP).[13] In 2003 the law was amended to define hydropower plants with capacity of less than 10 MW as SHP. In 2005, the Act on the Promotion of the Development, Use, and Supply of New and Renewable Energy was amended to remove the legal threshold for SHP and unify all hydropower plants regardless of their installed capacity, excluding pumped-storage plants.[14] Currently, the Renewable energy Portfolio Standard (RPS) only supports hydropower plants with capacity of up to 5 MW. Similarly, according to the new and renewable energy facility standards of the Korea Energy Agency, SHP is defined as hydropower of up to 5 MW. For the purposes of comparison with the previous editions of the Report, the present chapter will follow the up to 10 MW definition.

In 2020, there were 169 SHP plants in operation in the Republic of Korea with a combined installed capacity of 199.5 MW (Table 2).[15] The same year they accounted for approximately 9 per cent of total generation, which was approximately 671.3 GWh.[8] The SHP potential is estimated to be 1,500 MW.[16] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity increased due to the commissioning of new plants. Specifically, in 2018–2019, 14 new projects with a total installed capacity of 9.7 MW were launched (Table 3).[19] At the same time, the estimated potential has remained unchanged (Figure 2).

Figure 2. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in the Republic of Korea (MW)**



Source: EPSIS,[15] *WSHPDR 2019*,[16] *WSHPDR 2013*,[17] *WSHPDR 2016*[18]

Note: Data for SHP up to 10 MW.

Table 2. **Installed Small Hydropower Capacities in the Republic of Korea in 2020**

Owner	*Number of SHP plants*	*Capacity (MW)*	*Share (%)*
K-Water	56	84.88	42.54
Private companies	13	39.01	19.55
KRC (Korea Rural Community Corporation)	27	20.66	10.35
KHNP	8	11.27	5.65
Other	65	43.71	21.91
Total	**169**	**199.53**	**100.00**

Source: EPSIS[15]

In the Republic of Korea, various support systems have been put in place to facilitate SHP development. These include announcing the standard price and subsidizing the price difference. In addition, the development of the sector has been facilitated by the continuous decrease of development costs. As a result, the participation in SHP development of such stakeholders as local governments and private companies has greatly increased.

Table 3. **List of Selected Existing Small Hydropower Plants in the Republic of Korea**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Operator*	*Launch year*
Danyang Submarine	Chungbuk	2.400	N/A	K-water	2019
Sinson Port	N/A	0.150	N/A	N/A	2019
Starlight#1	N/A	0.099	N/A	N/A	2019
Daejung #1	N/A	0.050	N/A	N/A	2019
Daea	N/A	0.015	N/A	N/A	2019
Hydroenergy	N/A	0.009	N/A	N/A	2019
Sohyang	Jeonbuk	3.000	N/A	KRC	2018
Biryong	N/A	0.600	N/A	N/A	2018
Dowon	N/A	0.180	N/A	N/A	2018
Yecheon Yangsu	N/A	0.025	41	N/A	2018
Daesan	N/A	0.019	N/A	N/A	2018
Yanggu Dongmyeon	N/A	0.180	N/A	N/A	2017
Samhan Energy	N/A	2.800	N/A	N/A	N/A
Bohyunsan Dam	N/A	0.170	N/A	N/A	N/A

Source: Lee & Kim[19]

A further three SHP plants were under development as of the moment of writing of this chapter (Table 4).[20] These plants are planned as auxiliary facilities of thermal power plants. Presently, there are no further SHP investment plans to be developed based on preliminary and full feasibility studies.

Table 4. **List of Planned Small Hydropower Projects in the Republic of Korea**

Name	*Location*	*Capacity (MW)*	*Developer*	*Development stage*
Samcheok	Kangwon	N/A	SB Power Co.,Ltd.	Foundation
Goseong High	Gyeongnam	5.0	GG Power Co.,Ltd.	Structure
Sinseocheon	Chungnam	N/A	KOMIPO	To be completed

Source: Korea Power Exchange[20]

Note: Status as of 2021.

The hydropower potential of the Republic of Korea was calculated in a few stages using the data of the Korea Institute of Energy Research and the Electric Power Statistics Information System.[21,22] The total theoretical potential was estimated at 28 GW or 246 TWh/year, the technical potential at 12 GW and 41 TWh/year and the economic potential at 2.5 GW and 8.9 TWh/year. The potential was found to be particularly promising in the provinces of Gyeongnam, Gyeonggi and Gangwon.

RENEWABLE ENERGY POLICY

The key strategy related to climate change in the Republic of Korea is focused on mainstreaming climate change adaptation measures, including improvement of risk adaptation and strengthening of climate change monitoring, forecasting and evaluation.[22] On 28 October, 2020, the President declared the goal to reach carbon neutrality in 2050. Currently, various policies are being implemented to expand the supply of renewable energy, including the Renewable Energy 3020 Implementation Plan (2017) and the 5th New & Renewable Energy Technology Development, Use and Distribution Basic Plan (2020).[23,24] Through the 5th Basic Plan, the share of new and renewable energy in final energy was proposed to reach 13.7 per cent by 2034, with the target for generation raised to 25.8 per cent.

The Alternative Energy Development and Utilization and Supply Promotion Act is intended to promote technology development for, and use and dissemination of, new and renewable energy.[13] Through the law, the Government intends to promote the diversification of energy sources, stable electricity supply, environmentally friendly energy transition and reduction of greenhouse gas emissions. The objective is to contribute to the preservation of the environment, the sound and continuous development of the national economy and the promotion of national welfare. The main contents of the law include the establishment of a basic plan, renewable portfolio standard (RPS), feed-in tariff (FIT) and facility certification. The RPS obliges businesses with power generation facilities of 500 MW or more to supply not less than a certain percentage of electricity from new and renewable energy. In consideration of the Renewable Energy 3020 Implementation Plan, the RPS rate, which is currently at 10 per cent, is intended to be raised after 2023. According to the 4th Renewable Energy Basic Plan, there is also a plan to temporarily introduce FITs to ensure stable profits for businesses and simplify procedures.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The existing development targets in the hydropower sector mainly apply to large hydropower with installed capacity above 10 MW. According to the RPS implemented in January 2012, hydropower operators with installed capacity of 5 MW or less can receive Renewable Energy Certificates (RECs) and sell them on the trading market.

COST OF SMALL HYDROPOWER DEVELOPMENT

Based on the available data on several SHP projects, costs per unit vary greatly depending on the project and regardless of the project capacity (Table 5). On average, the cost is estimated at KRW 5,343 million (USD 4.1 million) per MW of installed capacity.[26]

Table 5. **Costs of Selected Small Hydropower Projects in the Republic of Korea**

Name	*Installed capacity (MW)*	*Cost (KRW (USD))*	*Cost per MW (KRW/MW (USD/MW))*
Sancheong	0.40	930,154,000 (714,360)	2,325,385,000 (1,785,900)
Mooju	0.40	388,731,604 (298,547)	971,829,010 (746,400)
SC Green Power Marine	2.75	30,544,210,159 (23,458,010)	11,106,985,512 (8,530,200)
Dongwha Water Purification Plant	0.12	892,973,000 (685,805)	7,441,441,667 (5,715,100)
Daecheong Dam	0.90	4,386,000,000 (3,368,456)	4,873,333,333 (3,742,700)

Source: Korea Power Exchange[26]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Available sources of financing for SHP projects include Region Supporting Business, Convergence Support Projects, RPS, FITs and Financial Supporting Projects. Region Supporting Business supports a variety of projects to supply new and renewable energy to infrastructure owned or managed by local governments. Under this scheme, between 1996 and 2020, 47 projects received a total of almost KRW 30 billion (USD 23 million) of funding. The scheme also covers SHP projects, mainly at water purification plants and agricultural reservoirs. Convergence Support Projects are financing programmes that cover part of the installation costs of new and renewable energy facilities installed in houses, public buildings and commercial buildings in specific areas. Under this programme, SHP received two grants in 2015, three in 2017 and two in 2018. Finally, the Electrical Industry Foundation Fund offers support for the promotion of renewable energy technology commercialization, with the support provided to hydropower-related projects totalling KWR 53.8 billion (USD 41 million) as of 2019.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key barriers to SHP development in the Republic of Korea include:

- Limited water resources that fluctuate throughout the year;
- A need for local technology development related to SHP and standardization;
- High dependence on foreign companies;
- Complaints from environmental groups and local residents;
- The burden of initial investment cost.

The key enabling factors for further SHP development are:

- Policy support for new and renewable energy projects, including SHP;

- A range of instruments of financial support;
- Availability of an undeveloped potential.

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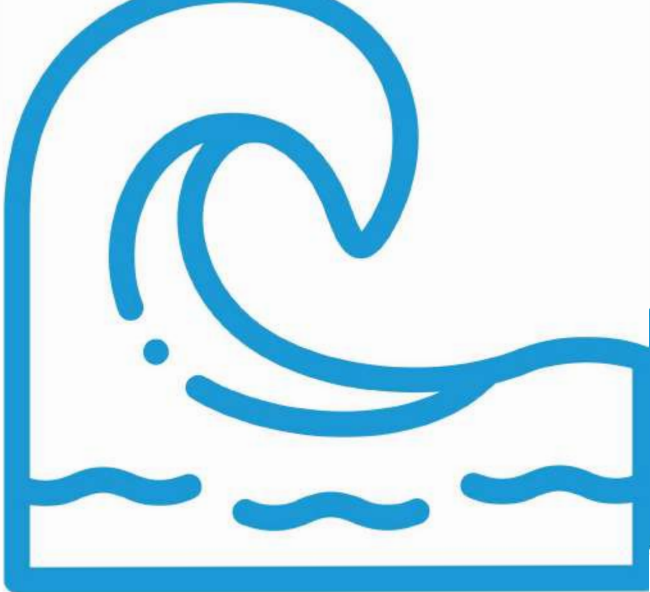


3.3. Southern Asia

Danila Podobed, International Center on Small Hydro Power (ICSHP)

Countries: Afghanistan, Bangladesh, Bhutan, India, Iran, Nepal, Pakistan, Sri Lanka

INTRODUCTION TO THE REGION

The electricity sectors of the countries in Southern Asia reflect the scale of their economies. India is by far the largest power producer in the region and one of the largest in the world, with a diversified electricity sector featuring significant investment in all major energy sources. By contrast, the electricity sectors of Nepal, Bhutan and Afghanistan are comparatively small, with Afghanistan being one of the least electricity-secure countries in the world. Nuclear power is a key energy source for several regional countries, including India, Pakistan and Iran. In Afghanistan, Bhutan and Sri Lanka, electricity generation is dominated by state-run companies, while in Bangladesh, India and Nepal, public and private companies account for roughly equal shares of generation.

Owing to the topography of Southern Asia, which includes the highest mountain ranges in the world, glaciers and extensive river valleys, the region is well-supplied with water resources appropriate for hydropower development. Hydropower accounts for nearly 100 per cent of the electricity generation in Bhutan and Nepal and plays a major role in the electricity sectors of every other country in the region with the exception of Bangladesh, where the development of hydropower is complicated by the slow-moving and meandering character of rivers.

An overview of the electricity sectors of the countries in the Southern Asia region is provided in Table 1.

Table 1. **Overview of Southern Asia**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Afghanistan	33	98	97	641	1,031	333	881
Bangladesh	165	96	95	20,817	72,320	230	655
Bhutan	1	100	100	2,343	8,877	2,334	8,876
India	1,353	86	N/A	382,151	1,610,968	50,996	167,029
Iran	83	99	N/A	85,155	334,445	12,088	30,375
Nepal	31	90	N/A	1,333	6,012	1,278	N/A
Pakistan	215	74	N/A	38,719	134,746	9,861	38,988
Sri Lanka	22	100	100	4,531	16,762	1,824	4,812
Total	-	-	-	**535,690**	-	**78,944**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in Southern Asia varies across countries, with Afghanistan, Bhutan, India and Nepal defining SHP as hydropower plants up to 25 MW, and Iran and Sri Lanka adhering to the up to 10 MW definition. In Pakistan, the up to 25 MW definition as well as the up to 50 MW definition are applied by different pieces of legislation. No official definition of SHP exists in Bangladesh.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Southern Asia (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Afghanistan	Up to 25 MW	N/A	N/A	83.2	1,200.0
Bangladesh	N/A	0.0	N/A	0.0	60.0
Bhutan	Up to 25 MW	32.4	23,296.0	8.4	8.9
India	Up to 25 MW	4,787.0	21,134.0	N/A	N/A
Iran	Up to 10 MW	19.5	90.8	19.5	90.8
Nepal	Up to 25 MW	662.5	4,000.0	N/A	N/A
Pakistan	Up to 50 MW	445.0	3,190.0	N/A	N/A
Sri Lanka	Up to 10 MW	424.6	873.0	424.6	873.0
Total	-	-	-	**535.7**	**2,232.7**

Source: *WSHPDR 2022*[1]

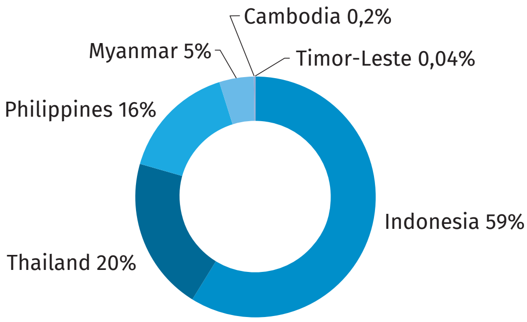
Note: *The up to 25 MW definition is also used.

India, Nepal, Pakistan and Sri Lanka all have robust SHP sectors, with SHP up to 25 MW accounting for approximately half of the total installed capacity of Nepal. The SHP sectors in these countries are additionally a major conduit for international cooperation projects. Sri Lanka has exported its considerable technical expertise in SHP to other parts of Asia as well as certain countries in Africa, while state-run agencies in Pakistan are involved in joint projects on hydropower promotion with China. In India and Nepal, the SHP sector is an important platform for private investments in energy development.

The installed capacity of SHP up to 10 MW in Southern Asia is 535.7 MW, while the potential capacity is estimated at 2,232.7 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the total installed capacity of SHP up to 10 MW in Southern Asia has decreased by 23 per cent while the potential capacity decreased by nearly 47 per cent, mainly due to the lack of reliable and current data for Nepal on SHP up to 10 MW. In recent years, SHP development has been most active in India, Sri Lanka and Nepal, and moderate in Pakistan. By contrast, the SHP sectors of Bhutan and Afghanistan are significantly smaller, despite a considerable assessed SHP potential, and new projects have mostly consisted of micro- and mini-hydropower plants that contribute relatively little to the electricity capacities of these two countries. Little potential for SHP development has been identified in Iran and Bangladesh.

The national share of regional installed capacity for SHP up to 10 MW by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

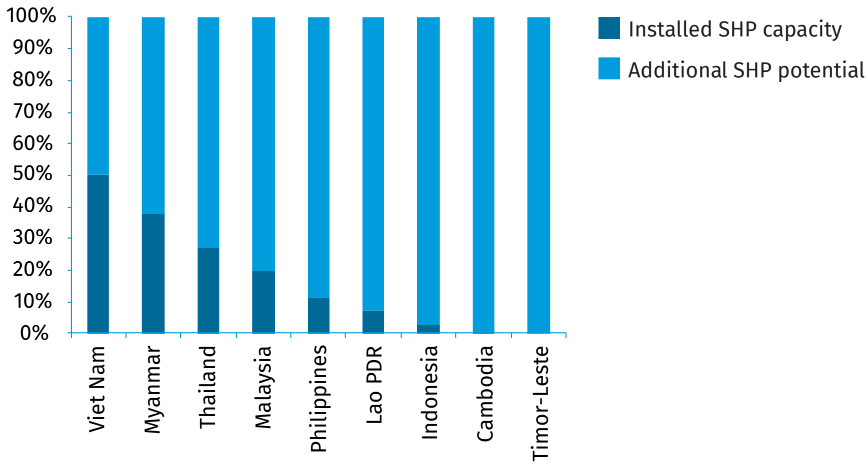
Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Southern Asia (%)**



Source: *WSHPDR 2022*[1]

Note: India, Nepal and Pakistan not included due to lack of data on SHP up to 10 MW; Bangladesh not included due to lack of installed capacity for SHP up to 10 MW.

Figure 2. **Utilized Small Hydropower Potential by Country in Southern Asia (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP up to 25 MW in the case of India, Nepal and Bhutan; for SHP up to 10 MW in the case of Sri Lanka, Iran, Afghanistan and Bangladesh; for SHP up to 50 MW in the case of Pakistan.

In **Afghanistan**, the total installed capacity of SHP up to 25 MW was estimated at 83.2 MW as of 2022, while potential capacity is estimated at 1,200 MW, suggesting that approximately 7 per cent has been developed. One new major SHP plant was commissioned in 2021, with another project nearing completion. However, only SHP up to 3 MW is classified as renewable energy under existing legislation. Most SHP development in Afghanistan in recent years has taken the form of mini- and micro-hydropower projects installed on isolated grids and funded by various support programmes, with an estimated 5,000 of such projects in different parts of the country.

There is no identified operational SHP capacity in **Bangladesh** as of 2022. The existence of several micro-scale SHP plants has been attested to in previous years, but they are no longer considered operational. The potential capacity for SHP up to 10 MW is estimated at 60 MW, with much of this potential concentrated in the hilly Chittagong region. Several recent studies have been carried out by national and international entities that identified a wide range of potential sites for new SHP construction as well as refurbishment of previously operational plants.

The total installed SHP capacity of **Bhutan** for SHP up to 25 MW was 32.4 MW in 2021, provided by 25 plants. With a single 24 MW plant providing most of this capacity. The total installed capacity for SHP up to 10 MW was 8.4 MW. Potential capacity for SHP up to 25 MW was estimated at 23,296 MW in 2017, indicating that significantly less than 1 per cent has been developed. There are no detailed data on the potential capacity for SHP up to 10 MW, but an estimate of 8.9 MW can be made on the basis of installed capacity and two additional projects under consideration as of 2021 with a total potential capacity of 0.5 MW. The overall installed SHP capacity of the country has changed little over the last decade, although several micro-scale plants have been commissioned. Several SHP projects with a total capacity of 83 MW are in the pipeline. Overall, existing plans for the development of hydropower resources in the country are focused on medium and large hydropower.

The total installed capacity of SHP up to 25 MW in **India** was 4,787 MW in 2021, while potential SHP capacity in the country is estimated at 21,134 MW, indicating that 22 per cent has been developed. The degree of SHP development varies considerably across different states, with Karnataka and Himachal Pradesh leading the country in both installed capacity and identified SHP potential. The SHP sector in India is actively expanding and a number of new SHP plants were commissioned in 2020. The Ministry of New and Renewable Energy is spearheading SHP development through support for SHP research and documentation of standards, while construction of new plants has been primarily carried out by the private sector.

The total installed capacity of **Iran** for SHP up to 10 MW was 19.5 MW as of 2021. There is a lack of clear data on potential SHP capacity in the country, but based on the sum of capacities for existing plants, planned project and identified potential sites, potential SHP capacity is estimated at 90.8 MW, indicating that over 21 per cent has been developed. Estimates of potential SHP capacity in the country have decreased following the cancellation of several planned projects in 2019. Little SHP development has taken place in the last decade, with the most recent utility-scale SHP plant commissioned in 2011.

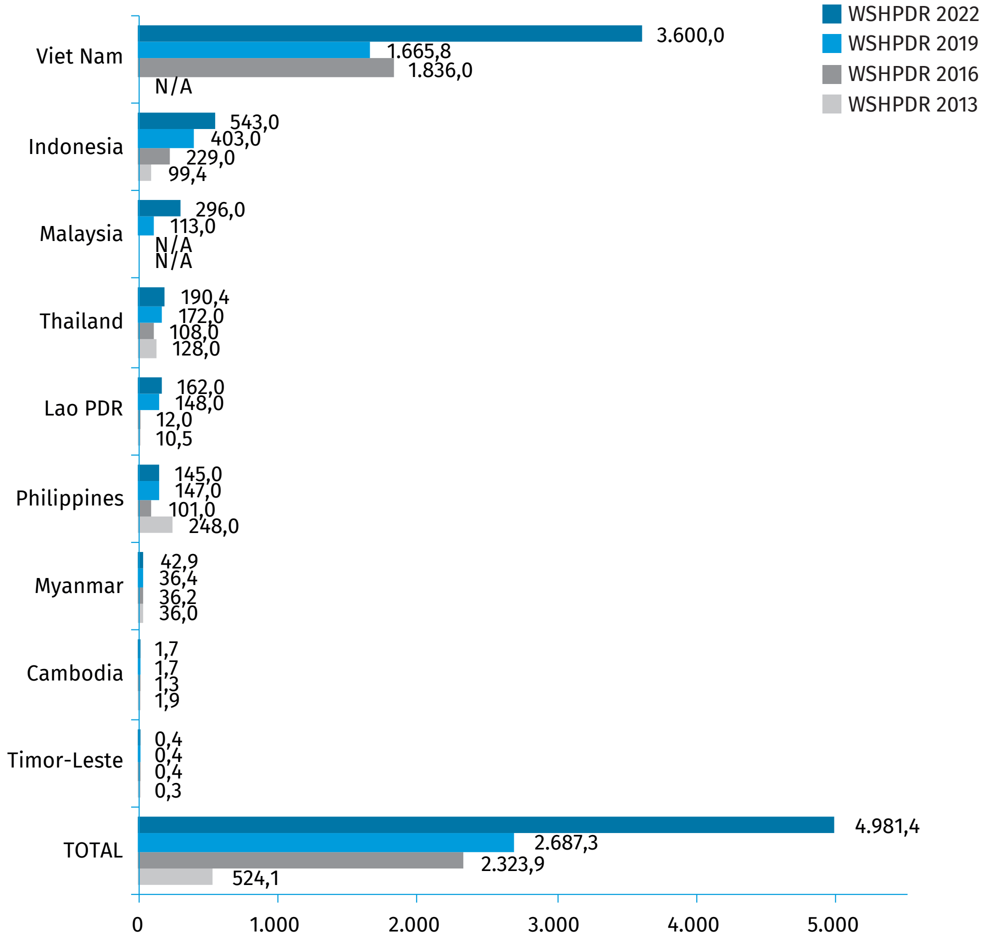
The total installed capacity in **Nepal** for SHP up to 25 MW was 662.5 MW in 2021, with SHP up to 10 MW accounting for the bulk of this capacity. Potential capacity for SHP up to 25 MW is estimated at 4,000 MW, indicating that approximately 17 per cent has been developed. In addition to utility-scale SHP plants, some 3,000 micro-hydropower plants operate in the country, providing power to rural and isolated areas. Development in the SHP sector is actively ongoing. As of 2021, a large number of prospective SHP projects totalling several thousand megawatts have either been granted generation licences or licences in preparation for feasibility studies.

The total installed capacity in **Pakistan** for SHP up to 50 MW was 445 MW as of 2020, while potential capacity is estimated at 3,190 MW, indicating that approximately 14 per cent has been developed. The Gilgit-Baltistan province hosts the largest concentration of SHP in the country and also contains the greatest estimated SHP potential. Development of SHP in Pakistan is pursued by a variety of public, private and international actors, including the Alternative Energy Development Board and the Pakistan Council of Renewable Energy Technologies. Joint Pakistan–China research centres for SHP technologies have been established in Islamabad and Peshawar and international funding for SHP projects has been provided by the Asian Development Bank, Swiss Agency for Development and Cooperation and the Aga Khan Foundation. At least five SHP projects were under construction as of 2021.

The total installed capacity of SHP up to 10 MW in **Sri Lanka** was 424.6 MW in 2019, provided by 205 grid-connected SHP plants. The potential capacity for SHP up to 10 MW in the country is estimated at 873 MW, indicating that approximately 49 per cent has been developed. The Ratnapura and Nuwara Eliya districts lead the country in installed SHP capacity. SHP development is very active in the country with over 20 new plants launched in 2018–2019, although procurement bottlenecks have led to a backlog of planned projects with a cumulative capacity of 100 MW, and no new power purchase agreements have been signed with developers since 2015. SHP developers from Sri Lanka have been expanding their reach internationally and pursuing projects in other parts of Asia as well as in African countries.

Changes in the installed SHP capacities of countries in the region compared to the previous editions of the *World Small Hydropower Development Report (WSHPDR)* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in Southern Asia (MW)**



Source: *WSHPDR 2022,*[1] *WSHPDR 2013,*[2] *WSHPDR 2016,*[3] *WSHPDR 2019*[4]

Note: For SHP up to 25 MW in the case of India, Nepal and Bhutan; for SHP up to 10 MW in the case of Sri Lanka, Iran, Afghanistan and Bangladesh; for SHP up to 50 MW in the case of Pakistan.

Climate Change and Small Hydropower

Precipitation patterns in the region have already been affected by climate change, but not consistently. The Himalayan region is characterized by heavy monsoon precipitation during summers and dry winters, and hydropower projects face risks due to Glacier Lake Outburst Floods (GLOFs). Most climate change models project a strengthened monsoon, resulting in an overall increase in runoff. Bhutan expects the most significant changes in streamflow after the mid-21st century due to increasing temperatures and higher glacier melt rates. Regions with low glacier coverage are expected to see reduced streamflow. Moreover, the impact on SHP generation and development is expected to have wide seasonal variation. Adaptive measures will be required in catchments utilized by SHP plants in order to reduce the adverse effects of seasonal flow variability. Moreover, floods and heavy sediment inflow should be considered in the operational and maintenance costs of SHP plants to avoid structural damage.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The prospects for further SHP development in **Afghanistan** are unclear, although the country possesses considerable untapped SHP potential. While most development in recent years has been supported by international donors, there is a lack of local technical capacity and private sector investment in SHP as well as a lack of means on the part of the local population to pay for electricity. In the near term, development of SHP in the Afghanistan is complicated by the decreased presence of international financing in the country after 2021.

SHP development in **Bangladesh** is complicated by the hydrological conditions featuring large, slow-moving rivers with low head, shifting riverbanks and frequent flooding, as well as by the country's high population density limiting the availability of land. A large number of potential sites have been identified and assessed in recent studies, but it is unclear how many are economically feasible due to the relatively high cost of construction.

While **Bhutan** possesses very significant hydropower resources, plans for their development have focused on large and medium hydropower at the expense of SHP. Additionally, there is a lack of targeted support programmes for SHP. Prospects for the development of SHP in the country include their lower cost relative to larger projects and ability to be funded by domestic firms without extensive reliance on foreign capital.

The conditions for SHP development in **India** are favourable overall and include access to government subsidies, power purchase guarantees for SHP operators on the part of electricity distributors, dedicated government loans and a well-established base of both technical documentation on SHP and data on SHP potential, in addition to considerable local technical expertise. Obstacles to SHP development include a lengthy licensing process and opposition to SHP construction by local communities and environmental activists, which along with other factors has contributed to rising capital costs of construction and decreasing competitiveness of SHP in the country relative to other renewable energy sources.

As in Bhutan, hydropower development in **Iran** has mostly focused on large-scale projects. Owing to the hydrological regime across much of the country, hydropower development is typically feasible on watercourses that can host a significant reservoir, with smaller rivers running dry during parts of the year. Climate change has also had an outsized impact on the country's hydropower resources. At the same time, Iran does possess a legislative framework supportive of renewable energy development and SHP in particular, including feed-in tariffs.

In **Nepal**, support for SHP development exists in the form of established government power purchase rates for SHP projects as well as a range of tax exemptions. The country has access to considerable local expertise in SHP and substantial undeveloped SHP potential. Obstacles to development include insufficient demand for additional projects, lack of clarity and integration in the regulation and licensing of plants and problems with grid connections. Multiple environmental issues also hamper development in the SHP sector, including excessive sedimentation of rivers, weak geology of river banks and inconsistent stream flow.

Development of SHP in **Pakistan** is hindered by a complicated licensing process and a lack of coordination among the involved government institutions, high cost of SHP construction due to a lack of local sourcing for components and low demand for electricity in regions where SHP potential is greatest. However, these obstacles are counterbalanced by the commitment to further hydropower and SHP development on the part of the Government of Pakistan, expressed in several programmes promoting SHP development, which include preferential lending conditions and guaranteed upfront tariffs.

The main obstacles to further SHP development in **Sri Lanka** are procurement bottlenecks and a long list of back-logged projects, lack of recent data on remaining undeveloped SHP potential and an absence of effective environmental monitoring of SHP construction and operation contributing to increased public opposition to further SHP development. The country has considerable local expertise in the SHP sector and previous government policy had established high purchase prices for electricity from renewable energy sources. However, recent changes in policy and the 2022 economic crisis in the country make it difficult to predict future price dynamics for electricity from renewable energy.

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Islamic Republic of Afghanistan

Najib Rahman Sabory, Kabul University

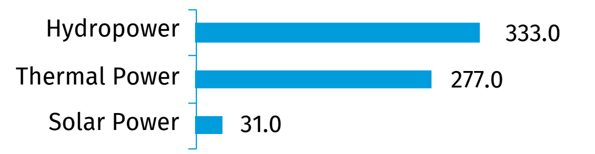
KEY FACTS

Population	32,890,171 (2020)[1]
Area	652,864 km² [1]
Topography	Afghanistan is a mountainous country, with mountains covering 63 per cent of the territory. The Hindu Kush Mountain Range splits the country from east to west. The average elevation is 1,100 metres above sea level, with 27 per cent of the country reaching an altitude of 2,500 metres. The highest point is Mount Noshaq at 7,485 metres, while the lowest point is the Amu Darya River at 258 metres.[2]
Climate	Afghanistan is located in the arid subtropics and has a semi-arid climate with cold winters and hot summers. The average temperature is 33 °C in June–August and 10 °C in December–February. The mountainous areas experience lower temperatures throughout the year, with winter temperatures being below 0 °C and summer temperatures being below 15 °C.[2]
Climate Change	Since the 1950s, the average annual temperature in Afghanistan increased by 1.8 °C. The most affected areas are in the south of the country, with an average temperature increase of 2.4 °C. The least affected regions are located in the east, with a temperature increase of 0.6 °C.[3]
Rain Pattern	Precipitation is most abundant in the winter, in the form of snow, and during the spring, in the form of rain. Annual precipitation averages 327 mm.[2] The wettest month is March and the driest month is September, with an average of 61.3 mm and 4.5 mm of precipitation observed over the 1991–2020 period, respectively.[4]
Hydrology	Afghanistan has five river basins: Kabul, Helmand, Harirud, Amu and Northern River. The Kabul River is the only river with a steady flow throughout the year, while most rivers turn to rivulets during dry seasons. Mountains form the backbone of the rivers in the country. The longest river, the Helmand, originates from the Central Hindu Kush Mountains. The Harirud River, flowing westwards and north-westwards to the border with Iran, is a key irrigation source in the Herat region.[5] Per capita water availability amounts to 2,775 m³.[6]

ELECTRICITY SECTOR OVERVIEW

Electricity generation in Afghanistan in 2020 totalled 1,030.9 GWh, which was almost 20 per cent lower than in 2019. The main source of electricity generation in the country is hydropower, accounting for over 85 per cent of total generation in 2020. Thermal and solar power accounted for the remaining 12 per cent and 3 per cent, respectively (Figure 1).[1] A further 5,152 GWh was imported from Uzbekistan, Tajikistan, Iran and Turkmenistan. Thus, imported electricity accounted for over 80 per cent of the total electricity supply in 2020.[1] The limited domestic generation remains the key challenge for energy security and energy access in Afghanistan.

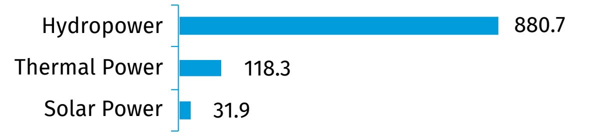
Figure 1. **Annual Electricity Generation by Source in Afghanistan in 2020 (GWh)**



Source: NSIA[1]

The total installed capacity of Afghanistan in 2020 stood at 641 MW. Hydropower accounted for 52 per cent of the total, thermal power for 43 per cent, while solar power accounted for 5 per cent (Figure 2).[7] The renewable energy potential in the country is estimated to exceed 300,000 MW, consisting of 222,849 MW of solar power potential, 66,726 MW of wind power potential, 23,310 MW of hydropower potential and 4,000 MW of biomass potential.[8]

Figure 2. **Installed Electricity Capacity by Source in Afghanistan in 2020 (MW)**



Source: IRENA[7]

Afghanistan has one of the lowest per capita electricity consumption rates in the world, however, the demand has been growing in recent years. According to the statistics of the national power utility, Da Afghanistan Brishna Sherkat (DABS), electricity consumption in 2018, 2019 and 2020 totalled 6.0 TWh, 6.3 TWh and 7.1 TWh, respectively. This indicates an increase in per capita consumption from 178 kWh in 2013 to 216 kWh in 2020.[9] Electricity demand is projected to continue growing in the coming decades. To meet this growing demand, the Afghanistan Renewable Energy Policy set a target of adding 5,000–6,000 MW of new generation capacity by 2032. Of this total, 95 per cent was set to come from renewable energy sources, primarily hydropower and solar power.[10]

The percentage of population with access to electricity was 98 per cent in 2019, including 100 per cent in urban areas and 97 in rural areas.[11,12,13] A significant share of the population with access to electricity relies on off-grid systems. Although more recent data are not currently available, in 2017 it was reported that of the rural population, which accounted for 77 per cent of the total population that year, only 11 per cent had access to the national grid.[14]

Previously, under the Power Service Regulation Act of Afghanistan, the Ministry of Energy and Water (MEW) was responsible for policy making for the power sector of Afghanistan. However, since 2020, MEW has been split into two entities: the Afghanistan National Energy Regulatory Authority (NERA) and the Afghanistan National Water Regulatory Authority (NWRA).

The state-owned utility DABS and NERA are the main public organizations involved in the development of the country's energy sector. NERA is responsible for the regulation of the energy sector, while DABS is responsible for the management of electricity generation, transmission, distribution, trade and operation and management of electricity generating facilities across the country. Other key stakeholders in the energy sector include:

- Energy Steering Committee (ESC), which is the highest decision-making body in the energy sector;
- Ministry of Commerce (MoC), which oversees imports and exports;
- Afghanistan Renewable Energy Union (AREU), which represents the private sector in the renewable energy sector;
- Afghanistan National Standards Agency (ANSA);
- National Environmental Protection Agency (NEPA);
- International organizations (e.g., United Nations Development Programme (UNDP)), international financial institutions (e.g., Asian Development Bank (ADB)) and donor agencies (e.g., GIZ).[14]

Electricity prices vary depending on the region. On average, the price for electricity from the national grid ranges from 0.03 USD/kWh to 0.60 USD/kWh.[14] Electricity tariffs for electricity from the national grid are set by the national power utility DABS. Prices for electricity generated by independent small power producers are fixed and negotiated between producers and consumers. At the moment, there is no national regulator in place to regulate electricity prices in the country. However, it is expected that the newly established power regulatory authority NERA will be responsible for setting national tariffs.

SMALL HYDROPOWER SECTOR OVERVIEW

According to the Renewable Energy Policy of Afghanistan, small hydropower (SHP) is defined as hydropower plants with capacity of up to 25 MW, with a further classification into pico-, micro- and mini-hydropower (Table 1). Under the policy, only projects up to 3 MW are classified as renewable energy projects.[10] For the purposes of comparison with the previous editions of the *World Small Hydropower Development Report (WSHPDR)*, this chapter will follow the up to 10 MW definition of SHP.

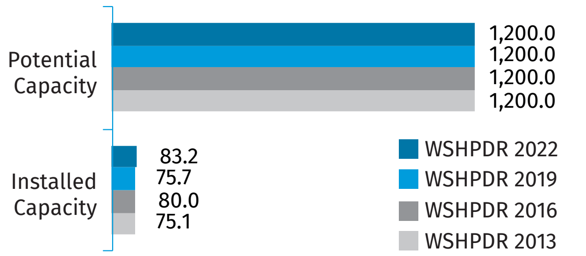
Table 1. **Classification of Small Hydropower in Afghanistan**

Category	Capacity
Pico	Below 2.5 kW
Micro	Below 250 kW
Mini	Below 2.5 MW
Small	Below 25 MW

Source: MEW[10]

The *WSHPDR 2019* reported that in 2016 the installed capacity of SHP plants in Afghanistan totalled 75.7 MW.[15] No new official statistics on total SHP installed capacity in the country have been made publicly available since then. However, it is known that one new SHP project was launched in 2021, the 7.5 MW Shorabak SHP plant (Table 2).[16] Also in 2021, the 9 MW Kamal Khan SHP plant was completed, however, as of the moment of writing of this chapter the powerhouse had not yet been installed due to financial issues and the plant was not in operation.[17] Thus, based on the available data, it can be estimated that the installed capacity of SHP plants up to 10 MW in the country was at least 83.2 MW in 2022. The SHP potential is estimated to be 1,200 MW and remains unchanged since the *WSHPDR 2019* (Figure 3).[18] The potential of mini- and micro-hydropower projects up to 1 MW in the country is estimated at 65.9 MW.[19]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Afghanistan (MW)**



Source: *WSHPDR 2019*,[15] Anadolu Agency,[16] Akbar & Burhan,[18] *WSHPDR 2013*,[20] *WSHPDR 2016*[21]

Table 2. **List of Selected Existing Small Hydropower Plants in Afghanistan**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Launch year*
Shorabak	Kokcha River	7.50	Reservoir	2021
Assadabad	Kunar River	0.70	N/A	1983
Ghorband	Ghorband River	0.30	N/A	1975
Charekar	Ghorband River	2.40	N/A	1973
Pul-e-Khumri 2	Pulikhumri RIver	8.79	N/A	1962
Grishk	Helmand River	2.40	N/A	1957
Pul-e-Khumri	Pulikhumri RIver	4.12	N/A	1950
Jabul Seraj	Salang River	2.50	N/A	1920
Chaki Wardak	Logar River	3.30	Reservoir	N/A
Yakchew	Suhanda District	0.10	N/A	N/A
Farghamero	Jurm District	0.07	N/A	N/A
Shasht (Rehab)	Rokha District	0.07	N/A	N/A
Khondut	Makhan District	0.06	N/A	N/A
Maloma	Karukh District	0.06	N/A	N/A
Kohnadeh	Khenjan District	0.05	N/A	N/A
Dahan e sai and Etafaq	Shikh Ali District	0.04	N/A	N/A
Ewate	Warseje District	0.04	N/A	N/A
Pirghola	Balkhaa District	0.04	N/A	N/A
Sure Bouhondy	Lalsarjungle District	0.03	N/A	N/A

Source: Anadolu Agency,[16] Danish et al.,[22] MRRD[23]

It is reported that under various support programmes over 5,000 mini- and micro-hydropower plants have been developed in Afghanistan. These plants are located in remote areas, not yet connected to the national grid, and feed power into mini-grids. Mini-grid solutions have been preferred in remote areas where the cost of connecting to the national grid would be too high and, thus, have been a central element of SHP development in many parts of the country.[19]

SMALL HYDROPOWER AVAILABLE FOR INVESTMENT

A number of SHP projects have been recommended by the Government of Afghanistan for investment. Table 3 lists some of these projects. Additionally, some solar-hydropower hybrid projects are also available for investment.[24]

Table 3. **List of Selected Small Hydropower Projects Available for Investment in Afghanistan**

Name	*Location*	*Potential capacity (MW)*	*Type of site (new/ refurbishment)*
Spogmee	Badakhshan Province	2.5	New
Kuraan Wa Munjan	Badakhshan Province	1.5	New
Yanghi Qalaa	Takhar Province	1.0	New
Farkhar	Takhar Province	0.5	New
Namak Ab	Takhar Province	0.5	New

Source: Government of Afghanistan[24]

Note: Data as of 2016.

RENEWABLE ENERGY POLICY

The legal and policy documents developed by the Government of Afghanistan and pertaining to the topics of climate change, environment and energy include the following:

- Environment Law, 2007;
- Energy Sector Strategy, 2007;
- Fuel Consumption Regulations, 2010;
- Afghanistan Green Urban Transport Strategy, 2014;
- Afghanistan Energy Efficiency Code for Building, 2015;
- Renewable Energy Policy, 2015;
- Intended Nationally Determined Contribution (INDC) of Afghanistan, 2015;
- Power Services Regulation Act, 2015;
- Afghanistan National Peace and Development Framework, 2017;
- Renewable Energy Roadmap, 2017.

The Renewable Energy Policy of Afghanistan set the ambition of reaching a 95 per cent share of electricity generation from renewable energy sources by 2032.[10] According to the 2019 National Housing Policy, environmental sustainability and energy efficiency are key to the development of the country's housing sector.[25] The INDC of Afghanistan emphasizes electricity production from hydropower, solar power, wind power and biomass.[26] The Environment Law mandates that the National Environmental Protection Agency (NEPA) is responsible for the development and implementation of national environmental policies and strategies in relation to water, solid waste, pollution and natural habitat.[27] Moreover, for the first time Afghanistan recognized climate change as a serious threat to the country in the National Peace and Development Framework (2017–2021).[28]

COST OF SMALL HYDROPOWER DEVELOPMENT

The average cost of micro- and mini-hydropower projects developed in Afghanistan under support programmes is estimated at approximately 1,850 USD/kW.[19]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Hydropower plants, particularly small-scale and run-of-river ones, are particularly sensitive to variations in water flow. In Afghanistan, hydropower generation is prone to seasonal variability and declines significantly during seasonal drops in river flow. Under the scenario of reduced precipitation, it is projected that by 2050 hydropower production in the country will decrease significantly. While exact estimates for SHP plants are not available, the larger 52.5 MW Kajaki and 100 MW Naghlu hydropower plants are expected to have zero production at least once every 10 and 20 years, respectively.[19]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Given that micro-to-small hydropower is mostly used in the country's rural areas, barriers to SHP development in Afghanistan should be considered in the wider context of barriers to rural infrastructure and renewable energy expansion. The key barriers include:

- Lack of concessionary loans (with sovereign guarantees) for rural electrification projects;
- The need for greater involvement from major international actors for infrastructure development, environmental protection and private sector support;
- Lack of private sector investment in rural energy, despite the recent increase in the number of companies and entrepreneurs;
- Lack of presence from international financial institutions to support the private sector;
- Lack of essential data for the electricity sector;
- Most consumers are either unwilling or unable to pay the full cost of electricity supply, which results in cash-flow deficits, particularly for operators of isolated mini-grids;
- Overall instability in the country is a constraint to the timely implementation of the power sector strategy;
- Limited number of trained personnel capable of producing improved generation units from standard technical plans;
- Limited geographic coverage and operational synchronization of the grid;
- Significant gaps in the legal and regulatory framework;
- Lack of coordination among responsible agencies for the planning and management of renewable energy development, which often leads to long lead times.[15]

At the same time, a number of factors that can be considered as enablers for further SHP development in the country exists, including:
Long history of hydropower generation in the country;
Significant untapped SHP potential;
Central place of renewable energy, including hydropower, in the country's energy strategy.

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Bangladesh

Shamsuddin Shahid, Universiti Teknologi Malaysia

KEY FACTS

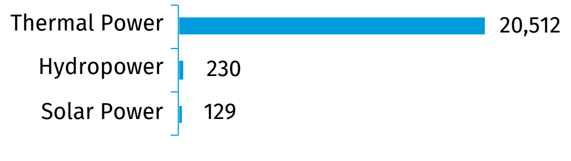
Population	164,689,383 (2020)[1]
Area	147,570 km^2 [2]
Topography	Bangladesh is situated on the deltas of several large rivers flowing from the Himalayas and the topography of most parts of the country is extremely flat. Approximately 50 per cent of the country lies below 10 metres and 90 per cent below 110 metres above sea level. Hills cover approximately 10 per cent of the country's area. The highest peak in Bangladesh is Saka Haphong at 1,052 metres, located in the extreme south-eastern corner of the country.[3]
Climate	Bangladesh has a tropical monsoon climate characterized by wide seasonal variations in rainfall, high temperatures and high humidity. The average temperature varies between 11 °C and 20 °C in the winter months (December to February) and between 24 °C and 31 °C in the pre-monsoon summer months (March to May). Average humidity varies between 71 per cent in March and 86 per cent in July.[4]
Climate Change	Bangladesh has experienced a gradual increase in mean annual temperatures between 1961 and 2014, at a rate of approximately 0.06 °C every 10 years. Over the past few decades, the country has been experiencing warmer winters with significant increases in the minimal seasonal temperature, as well as hotter summers during the monsoon and pre-monsoon season. Minimum seasonal temperatures have increased by 0.45–0.52 °C, while maximum temperatures rose by 0.42–0.87 °C.[5]
Rain Pattern	The annual average rainfall is 2,666 mm. Rainfall varies from 1,500 mm in the north-west to approximately 4,400 mm in the north-east. More than 70 per cent of the total annual rainfall occurs in the monsoon from June to September, while 3 per cent occurs during the winter season.[6]
Hydrology	Most of Bangladesh lies in the delta formed by the convergence of the Ganges, Brahmaputra and Meghna Rivers and their tributaries. The country is crisscrossed by numerous rivers, streams and brooks, generally running north to south as they meet up with the Ganges to flow into the Bay of Bengal. In the dry season, the numerous tributaries that lace the terrain may be several kilometres wide as they near the Bay of Bengal, whereas at the height of the summer monsoon season they coalesce into an extremely broad expanse of silt-laden water. Most of the rivers of Bangladesh are in their old stage and changes in the position of riverbanks and channels are a common phenomenon.[7,8]

ELECTRICITY SECTOR OVERVIEW

The total installed electricity generating capacity in Bangladesh was 20,871 MW as of the end of 2021. Thermal power including gas, furnace oil, diesel and coal provided 20,512 MW (98 per cent) of the total, hydropower provided 230 MW (1 per cent) and large-scale solar power provided 129 MW (less than 1 per cent) (Figure 1). [9,10] Additional solar power capacity exists in the form of small-scale installations, both on- and off-grid, as well as minor capacities of other renewable energy sources (RES) including wind power and biomass.[11] Finally, a further 1,160 MW was available for power generation in 2021 through interconnections with India.[9,10]

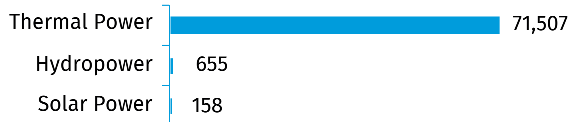
Generation of electricity during the 2020–2021 fiscal year reached 72,320 GWh, with thermal power providing 71,507 GWh (99 per cent) of the total, hydropower providing 655 GWh (less than 1 per cent) and other RES providing 158 GWh (less than 1 per cent) (Figure 2). Imports from India amounted to 8,103 GWh.[10]

Figure 1. **Installed Electricity Capacity by Source in Bangladesh in 2021 (MW)**



Source: BPDB[9,10]

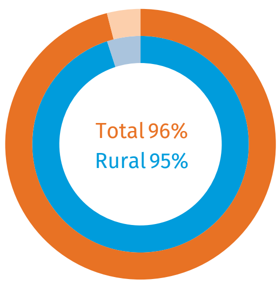
Figure 2. **Annual Electricity Generation by Source in Bangladesh in 2020–2021 (GWh)**



Source: BPDB[10]

Nationwide access to electricity in Bangladesh was approximately 96 per cent in 2020 and 95 per cent in rural areas (Figure 3).[12] Annual consumption of electricity in 2020–2021 amounted to 76,323 GWh, while transmission losses accounted for 2,330 GWh or approximately 3 per cent of available electricity.[10] Peak electricity demand in 2021 was 13,792 MW.[9]

Figure 3. **Electrification Rate in Bangladesh in 2019 (%)**



Source: World Bank[12]

The ownership structure of the electricity generation sector of Bangladesh includes state-owned companies operating 57 plants accounting for 10,146 MW (49 per cent) of the total electricity capacity, private companies operating 88 plants of 9,481 MW (45 per cent) and one plant of 1,244 MW (6 per cent) operated as a joint venture between a state-owned company from Bangladesh and a Chinese state-owned company.[9] The transmission grid is operated by the Power Grid Company of Bangladesh Ltd. (PGCB) and as of 2021 included 950 kilometres of 400 kV lines, 3,658 kilometres of 230 kV lines and 8,228 kilometres of 132 kV lines. The Bangladesh Power Development Board (BPDB) purchases electricity from generation licensees and sells it to distribution licensees using the transmission network owned and operated by PGCB, for which PGCB is paid a wheeling charge. Distribution of electricity is carried out by six companies (including the BPDB itself).[10]

The development of the electricity sector of Bangladesh is guided by the Power System Master Plan (PSMP) 2016. Key targets of the plan include the enhancement of infrastructure for energy imports, efficient development of domestic fossil fuel resources, upgrades to the national power grid, accelerated development of RES and human capacity development. The most significant challenge to be addressed by ongoing development of the electricity sector in the country is rapidly increasing electricity demand, projected to reach approximately 52,000 MW by 2041. To meet rising demand, the Government of Bangladesh plans to expand domestic generating capacity, including increasing total RES capacity to 3,864 MW and constructing 7,000 MW of nuclear power, as well as achieving a cumulative total of 9,000 MW of interconnected cross-border power supply for electricity imports by 2041. While the Plan does not include targets for conventional hydropower development due to perceived social and environmental risk, the potential for the construction of pumped-storage power plants (PSPP) for the provision of ancillary services is recognized.[13,14]

The Bangladesh Energy Regulatory Commission (BERC) regulates electricity tariffs in Bangladesh based on the Power Pricing Framework (2004), with tariffs differing by consumer category, electricity consumption volume (for residential consumers) and time of day.[15] Electricity tariffs for low-voltage connections current as of February 2020 are displayed in Table 1.[16]

Table 1. **Electricity Tariffs for Low-Voltage Connections as of February 2020**

Consumer category	*Usage category*	*Tariff in BDT/kWh (USD/kWh)*
1. Residential	Lifeline (0 to 50)	3.75 (0.041)
	0 to 75	4.19 (0.046)
	76 to 200	5.72 (0.063)
	201 to 300	6.00 (0.066)
	301 to 400	6.34 (0.070)
	401 to 600	9.94 (0.109)
	> 600	11.46 (0.126)
2. Agricultural pumping		4.16 (0.046)
3. Small industries	Flat Rate	8.53 (0.094)
	Off-Peak Time	7.68 (0.084)
	Peak Time	10.24 (0.113)
4. Educational, religious, and charitable institutions and hospitals		6.02 (0.066)
5. Construction		12.00 (0.132)
6. Street lights and water pumps		7.70 (0.085)
7. Battery charging stations	Flat Rate	7.64 (0.084)
	Off-Peak Time	6.88 (0.076)
	Super Off-Peak	6.11 (0.067)
	Peak Time	9.55 (0.105)
8. Commercial & office	Flat Rate	10.30 (0.113)
	Off-Peak Time	9.27 (0.102)
	Peak Time	12.36 (0.136)
9. Temporary		16.00 (0.176)

Source: BERC[16]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in Bangladesh. For the purpose of the current chapter, the up to 10 MW definition of SHP will be used. As of 2022, there were no operational SHP plants in Bangladesh, while potential SHP capacity was estimated at approximately 60 MW.[13,17] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed SHP capacity decreased 100 per cent due to a better understanding of the operational status of previously commissioned plants, while the estimate of potential capacity has increased marginally (less than 1 per cent) (Figure 3).[18]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Bangladesh (MW)**

Source: MPEMR,[13] Shahid,[17] *WSHPDR 2019*,[18] *WSHPDR 2013*,[19] *WSHPDR 2016*[20]

The first SHP plant in Bangladesh was installed for demonstration purposes in Bamerchara, Chittagong District, with a capacity of 10 kW. Another 10 kW plant was installed in Bandarban and a 50 kW SHP plant was constructed in Barkal Upazila, Rangamati District. However, these SHP plants are no longer operational.[17,21-,22,23] SHP potential in Bangladesh has been explored by different organizations over the last three decades. In 1981, the Bangladesh Water Development Board and BPDB jointly identified 19 prospective sites for SHP plants, while in 1984, a team of foreign consultants identified 12 potential sites for developing mini-hydropower plants with capacities between 4 kW and 616 kW. A 2021 country-wide study identified SHP potential on 232 rivers in Bangladesh. The hilly Chittagong region is considered to be one of the more promising locations for any future SHP development. In 2004, the Local Government Engineering Department (LGED) explored seven sites, mostly located in Chittagong, with capacities ranging between 3 kW and 30 kW and a total potential capacity of approximately 135 kW. Additionally, the Bangladesh Council of Scientific and Industrial Research (BCSIR) identified two sites in the Chittagong hill tract area with capacities of 5 kW and 15 kW.[21,22,23,24] Overall, the potential capacity of SHP in Bangladesh has been estimated at 60 MW.[13,25]

Potential sites for SHP development in Bangladesh include both previously operational plants that require repair or refurbishment as well as prospective new sites identified in earlier studies. A partial list of potential sites is provided in Table 2.

Table 2. **List of Selected Potential Small Hydropower Projects in Bangladesh**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/refurbishment)*
Barkal Upazila	Rangamati	0.050	N/A	Refurbishment
Sealock Khal	Bandarban	0.030	N/A	New
Madhobkundu	Moulvibazar	0.015	10	New
Bamerchara	Chittagong	0.010	10	Refurbishment
Sailopropat	Bandarban	0.005	6	New

Source: Razan et al.,[21] Islam et al.[23]

RENEWABLE ENERGY POLICY

As a signatory of the United Nations Framework Convention of Climate Change (UNFCCC), Bangladesh committed to an unconditional reduction of greenhouse gas (GHG) emissions in the power sector of 5 per cent, as well as a conditional reduction of 18 per cent, by 2030.[26] Likewise, adaptation to climate change impacts and the promotion of RES feature prominently in the PSMP 2016. Promotion of RES development and energy efficiency in Bangladesh is undertaken by the Sustainable and Renewable Energy Development Authority (SREDA). The Energy Efficiency and Conservation Master Plan up to 2030 prepared by SREDA in 2015 aims to achieve a 15 per cent increase in energy efficiency by 2021 and a 20 per cent increase by 2030.[27]

The RES policy of Bangladesh was drafted in 2008, with the aim of identifying domestic RES and the potential for their development, as well as facilitating investment in RES projects. Key targets of the policy included increasing the contribution of RES to 5 per cent of the total power demand by 2015 and to 10 per cent by 2020.[28] However, as of 2022 the electricity sector of Bangladesh was still short of meeting these targets. The PSMP 2016 therefore established a less ambitious target of 10 per cent of generation from RES by 2041.[13]

Feed-in tariffs (FITs) in Bangladesh are decided through a bidding process, where the Ministry of Power, Energy and Mineral Resources (MPEMR) can impose a maximum and minimum tariff.[29] In recent years, a number of power purchase agreements (PPAs) has been made with solar power plants at a FIT rate of 6.34–12.73 BDT/kWh (0.075–0.150 USD/kWh). The PPAs are concluded for 20 years under the "no electricity no payment" principle.[17]

The cost of generation from RES in Bangladesh is much less than that of generation from non-renewable energy sources, with the exception of gas. The cost of generation is lowest for hydropower, followed by gas-fired plants and solar power, and highest for plants fuelled by diesel and heavy furnace oil as well as for wind power plants. However, the selling price of electricity to BPDB is fixed at the same rate for both renewable and non-renewable energy sources.[17] Furthermore, domestic hydropower development is not prioritized by existing strategic planning due to relatively low potential and associated socio-environmental costs. The Government of Bangladesh has instead focused on exploring joint hydropower projects in neighbouring Nepal and Bhutan.[13]

COST OF SMALL HYDROPOWER DEVELOPMENT

The cost of SHP construction, operation and maintenance in Bangladesh is highly dependent on site-specific factors and displays the greatest degree of variance among all types of RES. According to the 2015 Scaling-Up Renewable Energy Programme (SREP) Investment Plan for Bangladesh, capital investment costs for SHP ranged from 2,090 USD/kW to 6,080 USD/kW, while fixed annual operation and maintenance (O&M) costs were estimated at 57–111 USD/kW.[25] Meanwhile, a 2014 assessment of hydropower resources in Bangladesh carried out by Stream Tech estimated capital investment costs for SHP sites under 10 MW ranging from 2,400 USD/kW to 10,300 USD/kW, with fixed annual O&M costs of 72–412 USD/kW, while costs of interconnection were estimated at 500–2,380 USD/kW.[30]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change in Bangladesh has led to an increase in extreme rainfall events, while glacial melt is likely to cause additional flooding in the coming decades.[5,6] Increases of mean seasonal rainfall have been particularly prominent along the coast, already the most flood-affected zone, and have been estimated at up to 42 mm/year during the monsoon season and up to 24 mm/year during the post-monsoon season. Glacial melt in the Himalayas may cause glacier mass losses of 45–68 per cent by 2100, leading to initial increases in runoff followed by the gradual drying of glacier-fed rivers in Bangladesh, as well as increased sedimentation.[5]

Increased precipitation volumes, frequency of extreme rainfall and runoff all pose risks to the development of hydropower in the country. Bangladesh is located in the delta of three major rivers and the fluvial geomorphology of the country is highly dynamic. Riverbank erosion, sedimentation and changes in the course of rivers, already widely observed in the country, are likely to increase and further complicate construction and maintenance of hydropower projects.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The most important barriers to SHP development of Bangladesh involve environmental and economic factors, including the following:

- Flat terrain in most parts of the country limiting hydropower potential;
- Dynamic fluvial geomorphology causing riverbank erosion and changes in the course of rivers;
- High population density limiting the amount of land available for SHP construction;
- High cost of SHP construction relative to potential capacity as a result of above factors;
- Lack of local technical capacity in conducting Environmental Impact Assessments;
- Future climate change impacts presenting an additional threat to potential SHP projects;
- Government plans prioritizing joint cross-border hydropower projects over domestic hydropower development.

The key factor enabling SHP development in the country is the large number of existing studies identifying potential SHP sites across the country and estimating costs.

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Bhutan

Choten Duba, Ministry of Economic Affairs

KEY FACTS

Population	748,931 (2020)[1]
Area	38,394 km^2 [2]
Topography	The country has elevations ranging from as low as 160 metres in the southern foothills to over 7,000 metres above the mean average sea level. Such a wide range is attributed to the fact that Bhutan is positioned in the most rugged mountain terrains of the Himalaya Range. The snow-capped Great Himalayan Range located in the north has its peak reaching over 7,500 metres above sea level. The northern region is characterized by an arc of glaciated mountain peaks with an arctic climate at the highest elevations. Conversely, the central region has fast flowing rivers curving out gorges.[2]
Climate	The climate of Bhutan falls into three distinct climatic zones — Alpine in the northern region, temperate in the inner region and subtropical in the southern plains and foothills. The region which falls under the Alpine zone remains cold with year-round snowfall and average temperatures fluctuating between 0 °C in the winter and 10 °C in the summer. The temperate zone is associated with temperate and subtropical climate characteristics and has hot and humid climatic conditions with temperatures ranging from 15 °C to 30 °C year-round.[2]
Climate Change	An analysis of the historical climate data shows a trend of increasing temperatures (both mean seasonal and mean annual temperatures) and decreasing mean annual rainfall. The climate projections for the periods of 2021-2050 and 2070-2100 also showed a trend of surface temperature increase of 0.8-3.2 °C. It can therefore be concluded that the annual rainfall over Bhutan is likely to increase in the future under the RCP 8.5 scenario, with an increase of 10–20 per cent in the first half of the century and reaching 30 per cent by 2100.[3]
Rain Pattern	Due to large variations in elevation, the average annual precipitation in the country varies widely from 40 mm (primarily from snowfall) in the severe climate of the north to as high as 7,800 mm at some locations in the subtropical region. The temperate central region has an average annual precipitation rate of approximately 1,000 mm. The country receives most rainfall in the summer monsoon season, which commences in late June and lasts through late September.[2]
Hydrology	The main rivers of Bhutan are fed by melting snow and flow from north to south. They are augmented with numerous east-west flowing tributaries as they flow towards the foothills of the Himalayan plains and join the Brahmaputra River in India further south. The country has four major river systems: Drangme Chhu, Puna Tshang Chhu, Wang Chhu and Amo Chhu. The glaciers in the northern part of Bhutan, which cover approximately 10 per cent of the total surface area, are an important renewable source of water for the country's rivers.

ELECTRICITY SECTOR OVERVIEW

The total energy generation in Bhutan in the year 2019 was 8,876.9 GWh (Figure 1). Hydropower was the main source of electricity generation accounting for 8,875.7 GWh or 99.99 per cent of the total. Large and mega-hydropower plants dominate the country's electricity mix, while pico-, mini- and micro-hydropower plants accounted for 17.8 GWh of total generation in 2019. An additional 0.006 GWh was from diesel generators and 1.2 GWh from wind power plants (0.6 MW) in the country.[4,5] The total installed capacity of the country in 2021 was 2,343 MW (Figure 2).[5,6] The installed capacity and generation data for solar rooftop installations are not available at this point of time.

Figure 1. **Annual Electricity Generation by Source in Bhutan in 2019 (GWh)**

Source: BPC,[4] DHPS[5]

Figure 2. **Installed Electricity Capacity by Source in Bhutan in 2021 (MW)**

Source: DHPS,[5] DGPC[6]

In 2005, Bhutan embarked on a rural electrification programme with the formulation of Rural Electrification Master Programme (REMP). As of 2020, 99.97 per cent of households were electrified through either on-grid systems via grid extension or off-grid systems supplied with solar rooftop installations in places where grid extensions are not feasible. The off-grid villages consist of 1,429 households and are in the process of receiving grid extensions under the Rural Electrification Programme (Phase-2) supported by the Japan International Cooperation Agency's (JICA) funding.

As Bhutan is almost 100 per cent dependent on hydropower generation, the country's electricity sector is prone to seasonal variability in generation depending on the availability of discharge in the rivers.[4,7] Since all the existing hydropower plants in the country are run-of-river systems, they are able to operate at only approximately 20 per cent of the total installed capacity in the dry periods. During such periods the generated electricity is barely sufficient for domestic consumption, with the shortages being met through imports from India. Thus, in 2019, Bhutan imported approximately 267.8 GWh to make up for the shortage of electricity during the winter season when the river discharge is at its lowest.[6] Nevertheless, Bhutan has been a net exporter of electricity. In 2019, the net energy exports amounted to 4,053.6 GWh (over 70 per cent of the total generation), which constituted a 10 per cent increase since 2018 due to increased generation and amounting to BTN 11.9 billion (USD 164,111) of revenue for the country.[6]

The domestic demand for electricity in the country has been rising consistently over the past years except for the year 2019 when it decreased to 387.7 MW compared to 399.4 MW in 2018. This exception from the general trend may be attributed to the decreased demand from the ongoing construction of hydropower projects.[7] Overall, over the years, increasing interconnections of rural households to the central grid have added to the growing electricity demand. Usually, higher power demand occurs during the winter months (December–March) when people use electricity for heating.[4]

Under the umbrella of the Ministry of Economic Affairs, the Department of Hydropower and Power Systems (DHPS) is mandated for the development of medium (between 25 MW and 150 MW), large (between 150 MW and 1,000 MW) and mega-hydropower projects (above 1,000 MW). On the other hand, the Department of Renewable Energy is responsible for the development of small hydropower (SHP) projects with an installed capacity 25 MW and below as well as of other sources of renewable energy such as solar power, wind power and biomass.[8,9] The state-owned utility Druk Green Power Corporation Limited (DGPC) operates and maintains the hydropower assets, while Bhutan Power Corporation Limited (BPC) is responsible for the transmission and distribution of electricity in the country.[4,6] The electricity sector is regulated by Bhutan Electricity Authority (BEA).[9]

The high reliance on a single electricity source implies certain risks for the electricity sector. These are associated with the rising energy demand in sectors such as transport and industry as well as the rapid growth of fossil fuel imports to make up for the generation shortfall in the face of the inevitable impact of the climate crisis. As a contribution towards the country's pledges to remain carbon negative, the Government of Bhutan adopted the Alternative Renewable Energy Policy (AREP) 2013. Through this policy, Bhutan strives to address the situation by diversifying its energy mix and promoting an independent energy system that not only meets the national energy demand, but also enhances energy security and contributes towards environmental preservation and economic development.[8] As of the moment of writing of this chapter, the country was in the process of formulating a regulation on grid integration of alternative renewable energy sources, including SHP projects with capacity of less than 25 MW, along with tariff determination with the intention to create an enabling environment for the promotion of renewable energy.

BEA, as the regulator body for the electricity sector, is mandated to develop and implement principles and procedures for tariff setting, subsidies and economic regulation of domestic tariffs.[9] The electricity tariffs in Bhutan are guided by the Domestic Electricity Tariff Policy (DETP) and the Tariff Determination Regulation 2016 formulated by BEA in due consultation with a wide range of stakeholders. As per the aforementioned DETP and subsequent regulation, electricity tariffs shall be approved by BEA after reviewing proposals submitted by the country's utility bodies: DGPC and BPC.[10] The tariffs are subject to revision every three years.[10] Table 1 shows the existing electricity tariffs in Bhutan which shall remain valid from 1 October 2019 to 30 June 2022 and will be thereafter subject to revision at regular intervals.

Table 1. **Approved Tariff Structure of Bhutan for the Period 1 October 2019 – 30 June 2022**

Tariff block	*Monthly consumption (kWh)*	*1 October 2019 to 30 June 2020 (USD/kWh)*	*1 July 2020 to 30 June 2021 (USD/kWh)*	*1 July 2021 to 30 June 2022 (USD/kWh)*
Low voltage (LV)				
LV block I (rural)	0–100	0	0	0
LV block I (highlanders)	0–200	0	0	0
LV block I (others)	0–100	0.018	0.018	0.018
LV block II (all)	101–500	0.037	0.037	0.037

Tariff block	Monthly consumption (kWh)	1 October 2019 to 30 June 2020 (USD/kWh)	1 July 2020 to 30 June 2021 (USD/kWh)	1 July 2021 to 30 June 2022 (USD/kWh)
LV block III (all)	> 500	30.049	0.500	0.500
Low voltage bulk		0.056	0.056	0.057
Medium voltage (MV)				
Energy charges (USD/kWh)		0.031	0.034	0.036
Demand charges (USD/kVA/month)		4.470	4.470	4.470
High voltage (HV)				
Energy charges (USD/kWh)		0.021	0.021	0.021
Demand charges (USD/kVA/month)		4.020	4.020	4.020
Wheeling (USD/kWh)		0.004	0.004	0.004

Source: BEA[10]

SMALL HYDROPOWER SECTOR OVERVIEW

In Bhutan, hydropower projects with an installed capacity of less than 25 MW are categorized as SHP plants.[8,9] Further classification of SHP is shown in Table 2.

Table 2. **Classification of Small Hydropower in Bhutan**

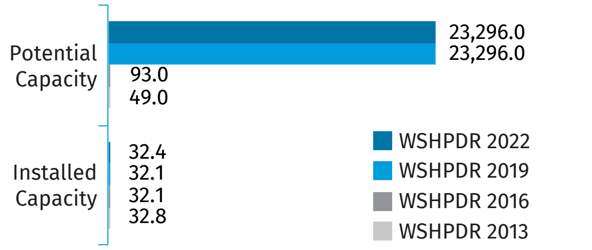
Category	*Capacity (kW)*
Pico	1–10
Micro	10–100
Mini	100–1,000
Small	1,000–25,000

Source: Department of Renewable Energy[11]

Bhutan has a total of 21 micro- and mini-hydropower plants (1–1,000 kW) with a combined installed capacity of 3.16 MW. Of these, 17 plants are managed by BPC and one each by the Department of Renewable Energy, the non-governmental organization Tarayana Foundation, the private community Gakhil Tshokpa and Thimphu District, respectively. A further four SHP plants (1–25 MW) with a total installed capacity of 29.19 MW (if the upper stage 24 MW Basochhu hydropower plant is included). Thus, the total installed capacity of SHP in Bhutan is 32.35 MW (Table 3).[7,12] According to the 10 MW definition of SHP, there are 24 existing plants with a combined installed capacity of 8.36 MW. As of 2021, a further two projects (0.53 MW) under the 10 MW definition were under investigation up to a detailed project report level. In 2019, the SHP generated a total of 122.79 GWh of electricity.[12]

The difference in installed capacity compared to the *World Small Hydropower Development Report (WSHPDR) 2019* is due to the rehabilitation of one mini-hydropower plant (Figure 3). Potential capacity has remained unchanged; however, it should be noted that the previous edition reported a wrong value, which has been corrected in the current chapter.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Bhutan (MW)**



Source: BPC,[7] DHPS,[12] *WSHPDR 2013*,[13] *WSHPDR 2016*,[14] *WSHPDR 2019*[15]

Note: Data for SHP up to 25 MW.

The new estimate of the theoretical potential for SHP of less than 25 MW (23,296 MW) was announced in 2017 as part of the Renewable Energy Master Plan formulation (2017–2032). The estimate indicates that the SHP potential remains largely untapped.[16] As of 2021, three projects with a total capacity of 56.30 MW had been investigated up to the reconnaissance level and four projects up to the detailed project report. The total capacity of planned SHP projects with a capacity of less than 25 MW was 82.83 MW.[17]

As provisioned under Bhutan's Sustainable Hydropower Development Policy–2008, the country intended to harness 10,000 MW of hydropower capacity by 2020. However, the target was later reduced to 5,000 MW to be developed by 2022.[16] As per the Renewable Energy Master Plan (REMP–2016), it was estimated that Bhutan has a theoretical hydropower potential of 41,088 MW as opposed to the previous estimate of 30,000 MW. Of the current theoretical potential, 26,683 MW is considered to be economically feasible for development.[18] However, the Power System Master Plan (PSMP–2040) has established that the country has a total potential of 3,700 MW from 155 identified potential sites. The disparity between the total potential estimates quoted in REMP and PSMP is attributed solely to the different methodology used.

As a next step under REMP, an assessment of SHP potential was conducted through a desktop study. In that study a total of 148 projects with a capacity ranging from 1 MW to 25 MW were identified in the whole country with a total combined estimated installed capacity of 1,553.46 MW. This constitutes roughly 7 per cent of the theoretical potential estimated in REMP.[19]

As of 2021, Bhutan had developed a total installed hydropower capacity of 2,334 MW (10 per cent of the potential with an addition of a 720 MW hydropower plant in July 2019), inclusive of small, mini- and micro-hydropower projects.[6] Furthermore, over 2,938 MW of new hydropower capacity was in various stages of construction and 6,200 MW of potential capacity was in the pipeline planned for development.[5]

Table 3. **List of Selected Operational Small Hydropower Plants in Bhutan**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Dali	Zhemgang District	0.018	Run-of-river	Tarayana Foundation	2016
Shingkhar	Bumthang District	0.009	Run-of-river	Gakhil Tshokpa	2015
Basochhu Upper Stage	Wangdue District	24.000	Run-of-river	DGPC	2009
Sengor	Mongar District	0.100	Run-of-river	DRE	2007
Chendebji	Trongsa District	0.070	Run-of-river	BPC	2005
Rongchu	Lhuentse District	0.200	Run-of-river	BPC	2001
Gangzur	Lhuentse District	0.120	Run-of-river	BPC	2000
Lingzhi	Thimphu District	0.008	Run-of-river	Thimphu District	1999
Rangjung	Trashigang District	2.200	Run-of-river	BPC	1996
Tintibi	Zhemgang District	0.200	Run-of-river	BPC	1992
Darachhu	Dagang District	0.200	Run-of-river	BPC	1992
Changchey	Changchey	0.200	Run-of-river	BPC	1991
Chumey	Bumthang District	1.737	Run-of-river	BPC	1988
Rukubji	Wangdue District	0.040	Run-of-river	BPC	1987
Tansibji	Trongsa District	0.030	Run-of-river	BPC	1987
Sherabling	Trongsa District	0.050	Run-of-river	BPC	1987
Bubja	Trongsa District	0.030	Run-of-river	BPC	1987
Tamzhing	Bumthang District	0.030	Run-of-river	BPC	1987
Ura	Bumthang District	0.030	Run-of-river	BPC	1987
Kekhar	Zhemgang District	0.020	Run-of-river	BPC	1987

Source: BPC,[7] DHPS[12]

Information pertaining to ongoing and planned SHP projects as well as potential sites available for investment is restricted from the public and thus are not presented in this chapter.

RENEWABLE ENERGY POLICY

With the objective to diversify the energy mix and also to enhance energy security, Bhutan adopted the Alternative Renewable Energy Policy (AREP) in 2013, which includes the promotion and development of other forms of renewable energy sources, including hydropower projects of installed capacity below 25 MW.[8]

The policy outlines the importance of deploying other renewable energy resources instead of depending on one single source of electricity, i.e., medium, large and mega-hydropower projects. The policy captures in depth the allocation process for the development of SHP and also elaborates on the mode of operation of projects after development (Build-Own-Operate/Build-Own-Operate-Transfer models, etc.). The policy stipulates that the developer shall be exempt from paying royalties on energy if the SHP project is developed for domestic purposes. This enables SHP to compete with the larger hydropower projects, which are comparatively cheaper and mostly destined for export.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The Sustainable Hydropower Development Policy–2008 outlined the requirement to develop a separate Renewable Energy Policy for the implementation of SHP projects of capacities below 25 MW and also to diversify the energy mix to enhance the energy security of the country. The concerned AREP was adopted in 2013 encompassing solar power, wind power, biomass and SHP.[8,9] However, with the intention to place more focus on the construction of ongoing larger hydropower projects, the policy did not set a target for SHP development and stipulated that one will be set in the future as needed.

As per the AREP, the development of SHP shall be allocated on the basis of open competitive bidding. If the SHP plant is meant for domestic consumption, the bidding shall be based on the lowest offered tariffs. For export-oriented projects, the tender shall be allotted to the one that offers the highest energy royalty. However, tariffs should be set with adherence to tariff regulations such as the Domestic Electricity Tariff Policy and the Tariff Determination Regulation 2016. Foreign direct investment (FDI) actors can only be allowed as minority shareholders. However, FDIs are not permitted for micro and mini hydropower projects. SHP projects are to be developed under the Build-Own-Operate-Transfer (BOOT) model for a concession period of up to 30 years, which is extendable for up to 15 years.[8] Upon the fulfilment of licence conditions, the project developer is issued with a licence to construct, operate and manage the plant(s).[20] Depending on the magnitude of the project and its environmental and social impact, the developer is required to carry out an Environmental Impact Assessment (EIA). Thereupon, an Environmental Clearance (EC) is accorded to the project developer by the National Environment

Commission (NEC), the nodal agency for administering and granting EC, regulated under the Environmental Assessment Act 2000 and the Regulation for Environmental Clearance of Projects 2002. Without an EC, the developer cannot proceed further with the project.[21]

According to the Fiscal Incentives 2016, hydropower projects introduced through the intergovernmental mode, which is a type of bilateral hydropower project development agreement, including the Associated Transmission systems, will be exempted from taxes such as sales tax (ST) and customs duty (CD). Other hydropower projects, which are to be developed through other modes shall be tax exempted (ST & CD) on machinery, materials and equipment imported for the purpose of hydropower project development.[17,22]

COST OF SMALL HYDROPOWER DEVELOPMENT

The majority of hydropower projects in the country, mostly medium- and large-scale ones, were developed under the intergovernmental mode, where certain portions of the funding consisted of grants. These made it possible to successfully realize the projects and make the cost of the energy derived from these projects much cheaper. When coupled with the subsidy scheme for domestic consumption, this makes SHP projects quite attractive. These factors have made the cost of electricity from SHP appear comparatively high.

As of 2021, electricity generation in Bhutan was dominated by medium, large and mega-hydropower plants, with the majority of projects being developed through the intergovernmental mode. The large quantity of electricity generated by larger-scale hydropower plants against their capital investment makes the cost of such projects attractive compared to other sources, including SHP. Therefore, promoting SHP in Bhutan faces a unique challenge as the country enjoys the availability of low-cost renewable electricity from larger hydropower plants. Therefore, given the current scenarios, the cost of SHP is found not to be competitive with larger-scale hydropower if only the cost of generation is considered.[8,16]

The cost of development of large hydropower projects in Bhutan ranges from BTN 70 million (USD 963,844) to BTN 90 million (USD 1,239,228). Based on detailed project reports of some SHP projects, the cost of SHP development ranges from BTN 84 million (USD 1,156,613) to as high as over BTN 1.6 billion (USD 22,030,736), with the size of the project, grid connectivity and locations being the key parameters defining the cost.[23,24,25] In the current scenario where the electrification rate has reached over 99 per cent, the remaining off-grid areas are located in the most remote parts of the country with some situated at a distance of more than nine days of walking. Supplying reliable electricity to these households has been found to be highly costly, largely due to transportation costs that can be as high as over 40 per cent of the total cost.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The AREP has provisioned for the establishment of the Renewable Energy Development Fund (REDF) to enable a favourable investment climate for alternative renewable energy sources, including SHP, with funds coming from various sources including a feed-in tariff (FIT), which is yet to be formulated. However, as of 2021, REDF had not been established. Noting the capital intensiveness, especially in the case of off-grid projects, the implementation of SHP in the country may be possible only through grants. Otherwise, their development would be techno-economically infeasible.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

A hydrological model simulation carried out for Bhutan by the Norwegian Water Resources & Energy Directorate (NVE) suggested that the flow in most of the streams will not change significantly from 1981–2010 to 2021–2050 for the catchments with high glacier coverage given the small changes in temperatures. After the mid-21st century, the glacier ice melt rate is projected to be higher due to increasing temperatures, which is to contribute to an increased flow volume in rivers. However, the catchments with low glacier coverage are expected to have a reduction in streamflow as a result of smaller amounts of precipitation, particularly during summer.[26] Because most of the SHP plants are located in the east-west oriented rivers with a smaller catchment area and a smaller glacier cover fraction, the reduced flow, as observed by the hydrological model, will most likely have an impact on the development of the sector. Therefore, adaptive measures, such as planning for reservoir and pump storage schemes would be a better option instead of the run-of-river type plants, which are highly dependent on seasonal flow variability.

Climate change has been affecting the precipitation pattern, impacting electricity production in the short, medium and long terms. It causes a decreased flow in other seasons and increased flooding during monsoons, which exposes hydropower facilities to the risk of floods and landslides in the rainy seasons and dwindled electricity generation in the winter due to decreased river flow.[3]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

To this date, the decision-making bodies and the public are of the view that the cost of electricity from SHP projects is higher than that from large hydropower projects. However, as per the findings of some of the SHP projects, the specific cost of generation from these small projects is comparable to, and even lower than, some of the medium-sized hydropower projects. Hence, venturing into SHP projects may not be as costly as anticipated and reported so far.

The following points summarize the main barriers to SHP development that have been identified:

- Development of larger projects still appears to be more viable based on economies of scale and hence more interest is being attracted to the implementation of bigger projects;
- Implementation guidelines for developing SHP projects are not yet in place;
- FITs or any other enabling mechanisms which will make SHP projects equally viable are yet to be formulated.

The following points summarize the main enablers for SHP development in Bhutan that have been identified:

- Equal and sometimes lower costs of SHP projects compared to medium-sized ones;
- Due to their small scale, SHP projects have a shorter construction period and hence the cost of their development is not impacted by Interest During Construction (IDC);
- The funds for SHP development can be comfortably sourced from within the country, thereby avoiding the need to look for international donors;
- Bhutan has a large energy surplus from hydropower during the monsoon season, but because of the projects being of the run-of-river type, the quantity of electricity generation decreases drastically during the dry months, during which the country has been importing power. Development of a few SHP projects could be a suitable alternative to meet this deficit during the dry months, while also supplementing the exports during monsoons;
- Considering that smaller projects can be easily funded by individuals or a consortium of firms, it can be a viable option to also explore development as the captive power to meet the industrial demands.

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India

Arun Kumar, Indian Institute of Technology Roorkee

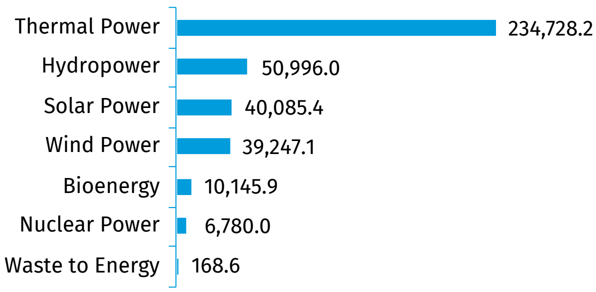
KEY FACTS

Population	1,352,621,350 (2021)[1]
Area	3,287,263 km^2 [2]
Topography	The south of India is characterized by an upland plain, Deccan Plateau, while flat to rolling plains are found along the Ganges River. Deserts take up most of the western part of the country and the Himalayas are located in the north with the highest point, Kanchenjunga, at 8,598 metres above sea level.[1,2]
Climate	Climate varies from tropical monsoon in the south to temperate in the north. Temperatures range between 32 °C and 38 °C in the valleys, while at the elevation of 4,500 metres the temperatures are typically below 0 °C. [1,2]
Climate Change	A significant overall impact of climate change on water resources is anticipated, including the rise in extreme variation in rainfall patterns, thereby increasing flood and drought frequency, the intensity of rainfall and spatial variability, the reduction in natural groundwater recharge and alterations in the flow of the river systems, which may significantly impact irrigation.[3]
Rain Pattern	The average annual rainfall is 1,074 mm. The monsoon season lasts from June to September with the south-west monsoon accounting for 70–95 per cent of annual rainfall in the country.[4]
Hydrology	India has numerous rivers with varying catchment areas and water resources. The catchment areas of the rivers flowing through the country are divided into 20 river basins. Of the major rivers, the Ganges–Brahmaputra–Meghna system is the largest with a catchment area of approximately 1.1 million km^2. The longest river is the Ganges (2,525 km). Other major rivers are the Indus, Godavari, Krishna, Mahanadi and Narmada. Many rivers are glacier-fed with most glaciers lying in the states of Sikkim, Jammu and Kashmir, Himachal Pradesh and Uttarakhand and a few glaciers in Arunachal Pradesh. The Siachen and Gangotri glaciers are two of the most important glaciers.[4]

ELECTRICITY SECTOR OVERVIEW

The total installed capacity of India, as of March 2021, was 382,151 MW, of which thermal power accounted for approximately 61 per cent, hydropower 13 per cent, wind power 10 per cent, solar power 10 per cent, biomass 3 per cent, nuclear power 2 per cent and waste for 0.04 per cent (Figure 1). The power generation infrastructure was owned by the Central and State Governments and the private sector with the shares of 26 per cent, 27 per cent and 47 per cent, respectively.[5]

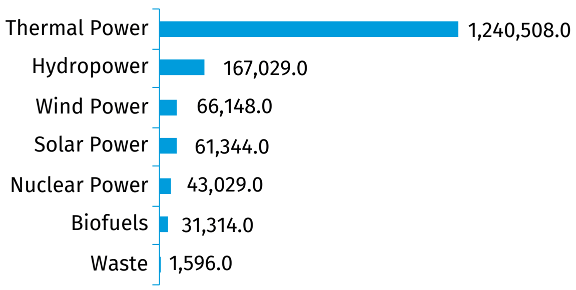
Figure 1. **Installed Electricity Capacity by Source in India in 2021 (MW)**



Source: National Power Portal[5]

Annual generation in 2020 amounted to 1,610,968 GWh. Of this, 77 per cent, or 1,240,508 GWh, came from thermal fossil fuel generation, including 72 per cent from coal. In contrast, non-hydropower renewable sources (i.e., excluding hydropower and waste) made up 158,806 GWh, or 10 per cent of the electricity generation mix.[6] Hydropower made up 10 per cent of total generation (Figure 2). Peak demand in 2020–2021 was at 190 GW, of which 0.4 per cent remained unmet.[5]

Figure 2. **Annual Electricity Generation by Source in India in 2020 (GWh)**



Source: IEA[6]

Electricity is a concurrent subject in India, meaning that the Central Government and the State Governments have the responsibility to promote its development and the authority to adopt necessary laws and regulations and to formulate and implement policies and development programmes.

The Central Electricity Regulatory Commission (CERC) at the federal level and the State Electricity Regulatory Commissions (SERCs) in the states are the statutory bodies possessing a quasi-judicial status under Section 76 of the Electricity Act (2003) and functioning as regulators of the power sector. CERC and SERCs are in charge of the electricity tariff system, transparent policies regarding subsidies and promotion of efficient and environmentally friendly policies. CERC was instituted primarily to regulate the tariffs of power generating companies owned or controlled by the Government of India and any other generating companies with a composite power generation scheme and interstate transmission. SERCs have similar functions but with jurisdiction limited to the respective state.

In 2018, the Government announced that all 657,009 villages in the country had been electrified.[4] Although all cities, towns and villages in India have access to electricity, only 86 per cent of households out of the total of 224 million do have access.[7] However, a village is considered electrified if at least 10 per cent of the homes and public buildings are connected to the grid, leaving some uncertainty as to how many households actually have access to electricity.[8] Officially, much progress has been made, with only 0.07 per cent of households remaining to be electrified as of 31 March 2019, all of which come from the state of Chhattisgarh.[9]

To improve electricity access, construction of new power plants as well renovation of existing plants is underway. Average power purchase cost in India in March 2021 was approximately USD 0.0513 (INR 3.85) per kWh.[10] In reality, tariffs vary from state to state, with each state having a unique tariffication system. In 2021, tariffs in Andhra Pradesh ranged from 1.45 INR/kWh (0.019 USD/kWh) to 9.95 INR/kWh (0.13 USD/kWh), depending on consumption groups and amount of monthly consumption. In contrast, tariffs in the state of Bihar range from 6.1 INR/kWh to 7.4 INR/kWh (0.082–0.099 USD/kWh).[11]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in India is up to 25 MW (Table 1).

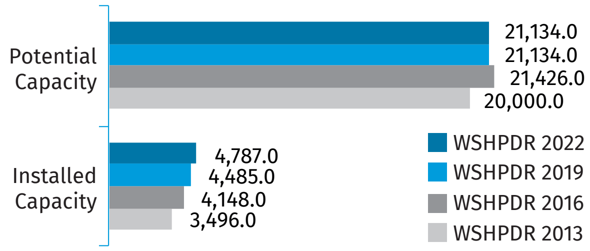
The installed capacity of SHP connected to the grid in India, as of March 2021, was 4,787 MW, while the potential was estimated to be 21,134 MW, indicating that 22 per cent has been developed (Figure 3).[12,13] Compared to the *World Small Hydropower Development Report* (WSHPDR) 2019, installed capacity has increased by approximately 7 per cent due to the introduction of new plants, whereas the potential has remained unchanged. The states with the most abundant hydropower capacity are Karnataka with 1,281 MW and Himachal Pradesh with 912 MW as of 31 March 2020.[14]

Table 1. **Classification of Small Hydropower in India**

Category	*Capacity (kW)*
Pico/watermill	Up to 5
Micro	Up to 100
Mini	101–2,000
Small	2,001–25,000

Source: MNRE[8]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in India (MW)**



Source: MNRE,[12,13] *WSHPDR 2013*,[14] *WSHPDR 2016*,[15] *WSHPDR 2019*[16]

The details on potential and installed SHP capacity by state are provided in Table 2. Moreover, there are also off-grid plants. While there are no data available on these, their combined installed capacity is estimated be in the order of 200 MW, or 4 per cent of total SHP installed capacity.

Table 2. **Status of Small Hydropower Development in India**

State	*Identified potential*		*Commissioned*		*Under development*	
	Number of sites	*Total capacity (MW)*	*Number of plants*	*Capacity (MW)*	*Number of projects*	*Total capacity (MW)*
Andhra Pradesh	359	409.32	44	162.11	–	–
Arunachal Pradesh	800	2,064.92	156	131.11	9	6.05
Assam	106	201.99	6	34.11	1	2.00
Bihar	139	526.98	29	70.70	–	–
Chhattisgarh	199	1,098.2	10	76.00	–	–
Goa	7	4.70	1	0.05	–	–
Gujarat	292	201.97	17	82.69	5	28.47
Haryana	33	107.40	9	73.50	–	–
Himachal Pradesh	1,049	3,460.34	197	936.11	12	127.00
UT of J& Kashmir	103	1,311.79	19	146.34	6	31.90

State	*Identified potential*		*Commissioned*		*Under development*	
	Number of sites	*Total capacity (MW)*	*Number of plants*	*Capacity (MW)*	*Number of projects*	*Total capacity (MW)*
UT of Ladakh	199	395.65	29	39.64	9	10.15
Jharkhand	121	227.96	6	4.05	–	–
Karnataka	618	3,726.49	170	1,280.73	3	13.00
Kerala	238	647.15	35	230.02	7	72.50
Madhya Pradesh	299	820.44	13	99.71	2	7.60
Maharashtra	270	786.46	70	379.58	9	10.40
Manipur	110	99.95	8	5.45	–	–
Meghalaya	97	230.05	5	32.53	2	25.50
Mizoram	72	168.90	18	36.47	2	8.50
Nagaland	98	182.18	12	30.67	1	1.00
Odisha	220	286.22	11	88.63	2	33.00
Punjab	375	578.28	56	173.55	6	4.30
Rajasthan	64	51.67	10	23.85	–	–
Sikkim	88	266.64	17	52.11	1	3.00
Tamil Nadu	191	604.46	21	123.05	–	–
Telangana	94	102.25	30	90.87	–	–
Tripura	13	46.86	3	16.01	–	–
Andaman and Nicobar Islands	7	7.27	1	5.25	–	–
Uttar Pradesh	251	460.75	9	49.10	1	1.50
Uttarakhand	442	1,664.31	102	214.32	14	28.58
West Bengal	179	392.06	24	98.50	–	–
Total	**7,133**	**21,133.62**	**1,138**	**4,786.81**	**92**	**414.45**

Source: MNRE[13]

As of March 2021, the potential of SHP (less than 25 MW) in India was estimated at approximately 21,134 MW with 7,133 identified sites. Of these, 4,488 sites (15,536 MW or 74 per cent of the total SHP potential) are located on small streams (run-of-river), 364 sites (1,558 MW or 7 per cent of the total SHP potential) are located on existing irrigation dams and 2,281 sites (4,040 MW or 19 per cent of the total SHP potential) are located on existing canals, falls and barrages.[14] Efforts are underway for a potential assessment of existing facilities such as pipelines for drinking water and industrial use, effluent outfall at water and sewage treatment plants, outlets of small dams and hydrokinetics in flowing channels and streams. Due to the availability of suitable turbines, ultra-low head potential (below 3 metres) is also being investigated and explored. A few installations on ultra-low head projects, such as irrigation canals and wastewater outlets, have been commissioned recently. The use of small-scale pumped-storage plants in the future is also being contemplated. Several operational sites that benefited from the Renewable Energy Certificate programme are listed in Table 3.

Table 3. **List of Selected Operational Small Hydropower Plants in India**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Khandi SHPP	District Kargil, UT of Ladakh	1.0	Kargil Renewable Energy Development Agency	2020
Baitarani SHPP	Keonjhar District of Odisha	24.0	N/A	2020
Matayeen SHPP	District Kargil, UT of Ladakh	0.6	Kargil Renewable Energy Development Agency	2020
Kachchh Branch Canal, SHPP-1, Banaskantha	Gujarat	10.0	Sardar Sarovar Narmada Nigam Limited	2020
Ichoo SHPP, Anantnag	Jammu & Kashmir	5.0	O2Z Trading and Industries Pvt. Ltd	2020
Amhata-III SHPP, Rewa	Madhya Pradesh	3.8	Amhata Hydro Energy Pvt. Ltd.	2020
Dhukwan SHPP, Jhansi	Uttar Pradesh	24.0	THDC India Limited	2020
Dikshi SHPP	West Kameng, Arunachal Pradesh	24.0	N/A	2019
Nuranang SHPP	Tawang, Arunachal Pradesh	1.0	N/A	2019
Zhangdongrong SHPP	West Kameng, Arunachal Pradesh	1.0	N/A	2018
Chilong SHPP	Chilong, Tai-suru, Kargil, Jammu & Kashmir	1.0	N/A	--
Biaras SHPP	Drass, Kargil, Jammu and Kashmir	1.3	N/A	2017
Turtuk MHPP	Ladakh	0.5	Ladakh Renewable Energy Development Agency	–

Source: MNRE[8,17]

Note: Plants listed are registered under the Renewable Energy Certificate programme.

The allotment of small and large hydropower projects is within the responsibility of the respective states. The State Governments' concern lies within the maximization of revenue for the state by way of free power and return on equity in the project. Presently, free power is to be given by hydropower producers to the state. However, in many states free power for SHP projects is nil or lower than 12 per cent. States are following different models for allocation (licensing/concession) of hydropower projects to private developers. While some states are allocating projects on the basis of per MW upfront payment to the state, others are making allocations on the basis of equity participation of the state at the cost of the developer or additional free power over and above the minimum prescribed percentage. States allocate projects to independent power producers (IPPs) with conditions that the project should revert back to the state after periods varying from 30 to 45 years. In a few states, projects up to and below 2 MW are reserved for licensing to entrepreneurs from these states only.

The Indian Ministry of New and Renewable Energy (MNRE) has a mandate on small-scale hydropower up to 25 MW at the federal level. Today, the SHP development programme is essentially driven by private investment in the different states. The focus of the programme is to lower the cost of construction, increase its reliability and set up projects in areas which give the maximum advantage in terms of capacity utilization. India has developed SHP on its existing irrigation dams and irrigation canal falls. From 1997 to 2015, approximately 1,100 MW has been developed on these existing facilities and are the first choice for the development by IPPs.[13]

Identified potential hydropower sites can be accessed from the Ministry of New and Renewable Energy Website.[14]

To make SHP cost-effective and reliable, 27 documents (standards, guidelines and manuals) covering the full range of SHP activities have been developed by the Department of Hydro and Renewable Energy (HRED), Indian Institute of Technology (IIT) Roorkee with support from MNRE through a consultative process. These documents are available for use by developers, manufactures, consultants, regulators and other interested parties.[18] An international-level hydropower turbine research and development laboratory serving as a design and validation facility, in addition to conducting research on hydropower turbines and other hydropower mechanical equipment conforming to national and international standards, has been established at HRED. The guiding framework for this laboratory meets international standards (IEC 60193 and ISO/IEC 17025).[19]

RENEWABLE ENERGY POLICY

At the 2015 Conference of the Parties in Paris, the Government of India announced ambitions to achieve approximately 40 per cent of cumulative installed capacity from non-fossil fuel-based resources and to reduce the emissions intensity of the Gross Domestic Product (GDP) by 33–35 per cent from the 2005 levels by 2030. By 2022, the country aims to have 175 GW of installed renewable electricity capacity as a short-term goal. To increase investment in renewable electricity in a cost-effective way, India has introduced national competitive auctions for wind power and solar photovoltaics and also supports measures such as Renewable Purchase Obligations.[20]

MNRE has the mission to ensure energy security through development and deployment of alternative fuels, such as hydrogen, biofuels and synthetic fuels, increase the share of renewable energy, energy availability and access, energy affordability (through cost-competitive, convenient, safe, affordable and reliable energy supply options) and energy equity in terms of per capita energy consumption at par with the global average level by 2050 through a sustainable and diverse generation mix.[8] The Indian Electricity Act 2003 has special provisions for the encouragement of the development of renewable energy and rural electrification. A new Renewable Energy Act 2015 has been drafted by the MNRE and at the moment of writing of this chapter, was under revision in the Indian Parliament.[13]

A Central Electricity Authority (CEA) study of the optimal generation mix for the year 2030 suggested that battery storage of 27 GW with four hours of duration and a pumped-storage project of 10 GW is required to sustain the renewable energy capacity added into the grid.[21] This should unlock an opportunity for developing pumped-storage projects in India, which would include some SHP.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

In August 1998 and thereafter in November 2008 and in March 2019, the Government of India announced a Policy on Hydro Power Development.[7] The Government has also prepared a policy amendment for hydropower projects, which at the moment of writing of this chapter was undergoing Government approval. Under this amendment, special funding, support on cost for infrastructure such as roads, bridges, flood protection and hydropower purchase obligation by Distribution Companies (DISCOM) has been announced.[7] Citizens adversely affected by hydropower projects have been made long-term beneficiary stakeholders in these projects by way of 1 per cent of free power on a recurring basis with a matching 1 per cent support from the State Government for local area development, as well as annual cash benefits, ensuring a regular stream of benefits. To enable the project developer in the hydropower sector to achieve a reasonable and quick return on investment, merchant sale of up to a maximum of 40 per cent of the marketable electricity has been allowed.[7]

The Central Government advises on hydropower matters and plays the role of an overall river basin planner and arbitrator. The MNRE issued guidelines for the State Governments regarding the development of policies on renewable energy development, notably for SHP.

The main points characterizing SHP and more broadly renewable energy policies of State Governments include:

- 24 States, namely Arunachal Pradesh, Andhra Pradesh, Assam, Bihar, Chhattisgarh, Gujarat, Haryana, Himachal Pradesh, Jammu and Kashmir, Karnataka, Kerala, Madhya Pradesh, Maharashtra, Meghalaya, Mizoram, Orissa, Punjab, Rajasthan, Sikkim, Tamil Nadu, Tripura, Uttarakhand, Uttar Pradesh and West Bengal, announced policies for setting up commercial SHP proj-

ects through private sector participation. The facilities available in the states include wheeling of power produced, banking, buy-back of power and facilities for third party sale;
- SHP sites with a combined capacity of over 7,000 MW have been allotted to the private sector for development;
- Many states permit power banking, i.e., supply to the grid of electricity surplus generated by an IPP in the rainy season in exchange of the receipt of the same amount of electricity from the grid in the dry season, for a period of a few months to one year;
- Buy-back of SHP is generally based on the guidelines issued by the CERC, with variations dependent on the respective SERCs;
- Some states provide other concessions such as lease of land, exemption from electricity duty and entry tax on power generation equipment;
- Some states (e.g., Punjab, Assam, Bihar, etc.) do not levy any water use charges on the quantity of water or head used by the power plant, while some levy it as a percentage of electricity tariffs;
- Some states have prescribed the minimum share of power to be produced from renewable sources and a renewable purchase obligation for up to 10 per cent to be purchased by a State Distribution Licensee in an incremental manner. Renewable Energy Certificate (REC) trading is not very successful in the country. However, power producers have demanded that the Government include SHP under hydropower purchase obligation;
- Some states have imposed a minimum environmental flow during the dry season and monitoring is preformed using automatic devices, with real-time data being published online. Some states have not implemented environmental flow regulations, which has attracted protests of activists.[20]

COST OF SMALL HYDROPOWER DEVELOPMENT

The costs of SHP projects commissioned during the last years in India have been compiled and analysed. The capital costs of the projects have gone up from INR 50 million (USD 0.74 million) per MW to INR 110 million (USD 1.48 million) per MW from 2005 to 2020, respectively.[22]

In hilly areas in particular, 60–70 per cent of project costs is related to civil works. Long-term hydrological data are not available, with variations in discharge being common phenomena and many projects having suffered on this account. For this reason, many green SHP projects may not be suitable for tariff bidding.[23]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The Indian Renewable Energy Development Agency (IREDA) under MNRE is a dedicated financial institution that provides loans and carries out other activities for the promotion of renewable energy sources, including SHP. Other financial institutions involved in the sector include Power Finance Corporation Limited, Rural Electrification Corporation Limited, the Industrial Development Bank of India and all commercial and private banks. Multinational financial institutions, such as the World Bank and the Asian Development Bank, have started providing funds for specific projects aiming to promote clean energy in India, normally through the above-mentioned financial institutions.

Along with other renewable energy sources, the Government of India provides a subsidy for the development of SHP for public, society and private sector in different proportions depending on the location, degree of difficulty and installed capacity. RECs are also offered as part of the Renewable Purchase Obligation programme, under which many SHP projects have benefited. Thus, 30 SHP generators were accredited as of July 2021.[24]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

A sociological survey of Himachal Pradesh has noted the impacts of SHP on local springs, which have been disappearing in some cases due to the construction of tunnels for hydropower plants. The same study highlights the frequency of disasters such as earthquakes, floods and landslides that affect the region, which would also have an impact on SHP.[25] These impacts are likely to increase in frequency as climate change progresses.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are several barriers for SHP development in India and these vary from state to state, depending on the availability of discharge data, site, feasibility reports and clearances. These barriers may be summarized as follows:
- Long process of obtaining project licences, clearances, permissions and finances;
- Lack of involvement of local people;
- Lack of clarity regarding the ownership of SHP projects by State Governments as each project receives support of the corresponding State Government in the form of water royalty, local area development, assistance, etc.;
- Local populations and activists consider SHP the same as large hydropower in terms of environmental, rehabilitation and resettlement implications and protest against SHP projects, too;
- Due to a continuous increase in capital costs of SHP

projects, the increasing burden of various financial loading such as water use tax, load tax, transmission charges, right of way charges and environmental flow as well as the difficult and time-consuming process of obtaining forest land on lease, the private sector does not find SHP attractive for investment. The SHP-based tariff is being compared with solar power, which receives several concessions;

- Lack of government initiative and will to fight the legal matter in courts, which causes a delay in implementation, thus increasing the costs and making tariffs non-competitive;
- Mismatch between the announced policies and their application on the level of field offices, resulting in delays in clearances and execution;
- Lack of available discharge data;
- Lack of available suitable spare parts and grid infrastructure for power evacuation.

The following points summarize the main enabling factors for SHP in India:

- A strong groundwork of data for potential sites to be developed in each state;
- Government support in the form of a subsidy that is available for SHP projects;
- A dedicated loan institution under IREDA;
- Several policy mechanisms dedicated to the regulation of the SHP sector;
- Funding support available for infrastructure costs;
- Hydropower purchase obligation for distribution companies;
- Documents (standards, guidelines and manuals) covering the full range of SHP activities have been developed by the Department of Hydro and Renewable Energy (HRED), Indian Institute of Technology (IIT) Roorkee with support from MNRE through a consultative process.

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Islamic Republic of Iran

Mohammad Hajilari and Samira Heidari, Afry Switzerland

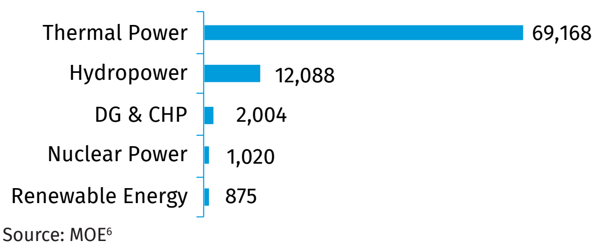
KEY FACTS

Population	82,913,906 (2019)[1]
Area	1,648,000km^2 [2]
Topography	Iran is situated on a plateau at an average elevation of 1,200 metres above sea level. The Zagros and Elburz Mountain Ranges form a V shape upon the plateau, with the apex in the north-west, while the area between the two mountain ranges is covered in salt flats and barren deserts. Mount Damavand, north-east of Tehran and the highest point in the country, rises to 5,671 metres, while the Caspian littoral region is situated below sea level. Iran is geologically unstable and occasionally experiences severe earthquakes.[2]
Climate	Iran has a continental type of climate. The skies are clear on more than half the days during the year and seasonal transitions are rapid.[2] January is the coldest month, with temperatures ranging from 5 °C to 10 °C, while August is the hottest, with temperatures ranging from 20 °C to 30 °C or more.[3]
Climate Change	According to the Third National Communication of Iran to the United Nations Framework Convention on Climate Change, the mean annual temperature for the period 2016–2030 is expected to increase by 0.2-1.4 °C in different parts of the country, relative to the period 1982-2009. Precipitation for the period 2016-2030 is projected to decrease in the spring, autumn and winter by 10-20 per cent in the eastern, north-western and south-western parts of the country and by 30 per cent in the spring in the southern part of the country, relative to the period 1982–2009.[4]
Rain Pattern	Average annual precipitation in Iran varies from less than 50 mm in the south-east to 1,980 mm in the Caspian region; the annual average precipitation for the country as a whole is approximately 400 mm. Over half of the annual precipitation falls during the winter period.[5]
Hydrology	Iran has three large rivers: the Kārūn, Sefīd and Zāyandeh. The Karun River originates in the Zargos Mountains and flows to Shatt Al-Arab in the south, emptying into the Persian Gulf. The Sefīd River originates in the Elburz Mountains in the north, flowing out onto the Gilan plain and emptying into the Caspian Sea. The Zāyandeh River flows from its source in the Zargos Mountains in a south-easterly direction, terminating in the Gāvkhāneh Marsh. Other streams in Iran are primarily seasonal with a highly variable flow, causing regular floods in the spring but drying up during the summer. The largest lake in the country is Lake Urmia in the north-west, with an area of approximately 5,200–6,000 km^2.[5]

ELECTRICITY SECTOR OVERVIEW

In March 2021, the total installed capacity of the Islamic Republic of Iran was 85,155 MW, with thermal power plants providing over 81 per cent of the total capacity, hydropower plants 14 per cent, distributed generation (DG) and combined heat and power (CHP) plants 2 per cent, nuclear power plants 1 per cent and other renewable energy sources (wind power, solar power and biofuels) approximately 1 per cent (Figure 1). Compared with the *World Small Hydropower Development Report (WSHPDR) 2019*, the total installed capacity of Iran increased by 15 per cent, largely as a result of the expansion of thermal power, including gas and combined cycle plants.[6,7]

Figure 1. **Installed Electricity Capacity by Source in Iran in 2021 (MW)**

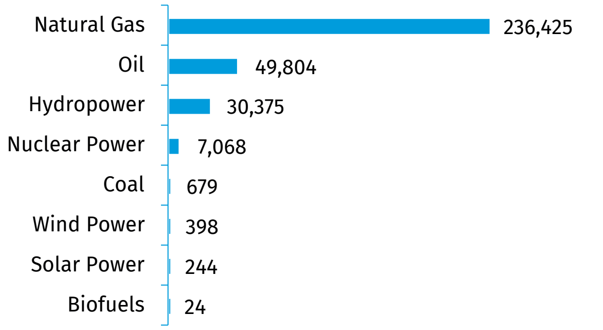


Source: MOE[6]

Total gross electricity generation in 2020 reached 334,445 GWh.[6] However, the last year for which disaggregated data on generation is available, was 2019, when total gross generation reached 325,017 GWh. Of this total, natural gas-fired power plants generated 73 per cent, oil-fired plants 15 per cent, hydropower plants 9 per cent, nuclear power plants

2 per cent and both coal-fired power and other renewable energy sources less than 1 per cent (Figure 2).[8] Thus, the majority of electricity generation in 2019 was provided by fossil fuels (88 percent).

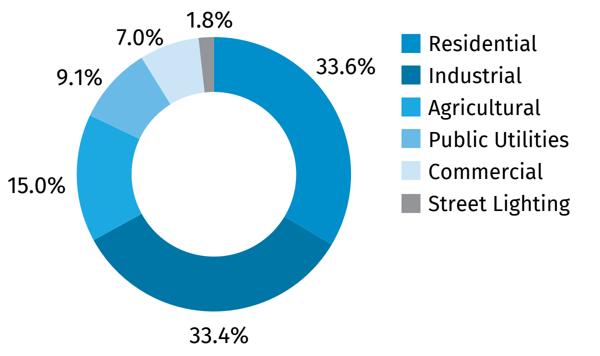
Figure 2. **Annual Electricity Generation by Source in Iran in 2019 (GWh)**



Source: IEA[8]

In 2018/2019 (Iranian year lasting from March 2018 to March 2019), electricity consumption equalled 261.4 TWh, representing a 3 per cent increase over the previous year. Consumption was dominated by the residential sector (87.7 TWh) and the industrial sector (87.4 TWh), with public utilities, commercial and agricultural sectors and street lighting consuming a combined total of 86.2 TWh (Figure 3).[9] In 2018/2019, Iran exported 6.3 TWh of electricity, representing a 23 per cent decrease over the year 2017/2018, and imported 2.6 TWh of electricity, representing a 34 per cent decrease over the previous year. With generation reaching 310.9 TWh in 2018/2019, electricity losses that year equalled 45.8 TWh, or approximately 15 per cent of total electricity supply.[9] The national electrification rate was 99.1 percent in 2019.[10]

Figure 3. **Electricity Consumption by Sector in Iran in 2018/2019 (%)**



Source: Central Bank of the Islamic Republic of Iran[9]

In 2016, building on the experience of the construction and operation of the first unit of the Bushehr nuclear power plant, the Atomic Energy Organization of Iran prepared tender documents for the construction of two new nuclear power plants of the third-generation pressurized light-water reactor type. The two additional plants will also be located at Bushehr and will have a capacity of 1,057 MW each. The construction plan is in line with the targets and legislation of the Islamic Consultative Assembly (the Parliament), specifically, with the goal of increasing the country's nuclear power installed capacity to 20,000 MW. The plans follow regulations on nuclear power used internationally as well as the recommendations of the International Atomic Energy Agency. Construction of unit 2 of the Bushehr nuclear power plant commenced in 2019 and it is expected to enter commercial operation in 2024.[11,12]

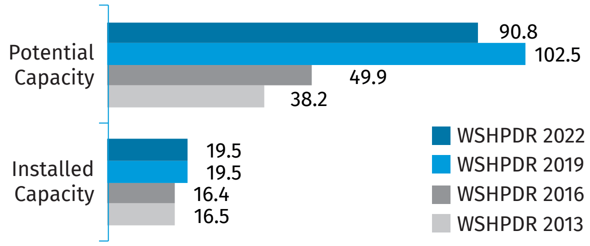
The electricity tariff rates for different classes of consumers are determined based on the average tariff by the Ministry of Energy (MOE). The average tariff is defined based on a number of estimations including availability for sale, revenue, capital and operating expenditure.[13] In 2019, the consumer tariff for electricity was approximately 0.007 USD/kWh.[14]

In order to control the budget deficit and to manage excess energy consumption, in February 2010 the Government embarked on an aggressive and ambitious price reform. According to the Targeted Subsidies Law, fossil fuel (petrol, oil, liquefied gas and kerosene) prices were supposed to rise by up to 90 per cent within five years and electricity prices would also increase to cover generation costs. In the first year of implementation, the plan was expected to generate approximately USD 10–20 billion in revenue. The generated funds were to be allocated as follows: 50 per cent to be distributed in the form of cash handouts to households, 30 per cent to support industries affected by the energy price hikes, public transportation and infrastructure and 20 per cent to cover discretionary expenses. The subsidy reform faced a number of delays, leading to the deferment of its completion until March 2021, as stated in the Sixth Five-Year Development Plan of Iran.[15,16]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Iran is up to 10 MW. As of early 2021, there were 10 SHP plants in operation (Table 1) with a total installed capacity of 19.50 MW.[17] Furthermore, the Sooleh Dokal SHP plant (4.4 MW), Zivakeh SHP plant (6.0 MW) and Zayande Roud regulator dam (8.5 MW) are currently under construction or ready to begin construction (Table 2).[17] A further 52.48 MW of capacity are available for investment.[17] While there is lack of clear information on the country's potential SHP capacity, based on the sum of capacities of existing plants, ongoing projects and potential SHP sites, total potential capacity is estimated to be at least 90.83 MW, with 71.33 MW remaining undeveloped. Accordingly, compared to the *WSHPDR 2019*, the installed capacity of SHP in Iran has not changed, while the economically feasible potential capacity decreased by 11.65 MW (Figure 4). This reduction is due to the cancellation of some potential projects since 2019.[17]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Iran (MW)**



Source: *WSHPDR 2019*,[7] IWPCO,[17] *WSHPDR 2013*,[18] *WSHPDR 2016*[19]

The Government-owned Iran Water and Power Development Company (IWPCO) is responsible for hydropower development projects as well as the operation and development of water supply facilities. Iran Water Resources Management Company (IWRM) provides administrative support for effective operation of water resources and development of hydropower potential capacities in the country.[7]

Table 1. **List of Operational Small Hydropower Plants in Iran**

Project name	*Location (province)*	*Capacity (MW)*	*Operator*	*Launch year*
Arde	Gilan	0.13	MOE	1991
Darre Takht 1	Lorestan	0.68	MOE	2005
Darre Takht 2	Lorestan	0.90	MOE	2005
Gamasiab	Hamedan	2.80	MOE	1999
Micro Power Plants	-	0.23	MOE	2004
Piran	Kermanshah	8.40	MOE	2011
Sarrud	Khorasan	0.07	MOE	1987
Shahid Azimi	-	1.00	MOE	1995
Shahid Talebi	Fars	2.25	MOE	1994
Tarik	Gilan	3.00	MOE	N/A
Total		**19.45***		

Source: IWPCO[17]

Note: Discrepancy is due to rounding.

Table 2. **List of Ongoing and Planned Small Hydropower Projects in Iran**

Project name	*Location*	*Capacity (MW)*	*Developer*	*Planned launch year*	*Development stage*
Sooleh Dokal	West Azarbayjan	4.4	IWPCO	N/A	Construction
Zayande Roud regulator dam	Isfahan	8.5	IWPCO	N/A	Ready for construction
Zivakeh	West Azarbayjan	6.0	IWPCO	N/A	Ready for construction
Total		**18.9**			

Source: IWPCO[17]

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

As of 2021, 52.48 MW of SHP capacity with total potential generation of 231.36 GWh per year was available for investment (Table 3).[17]

Table 3. **Small Hydropower Projects Available for Investment in Iran in 2021**

Project name	*Province*	*Capacity (MW)*	*Annual generation (GWh)*	*Type of site*
Alamoot Rood	Qazvin	1.7	9.4	New
Masuleh1	Gilan	1.8	9.4	New
Nari	West Azarbayjan	2.5	9.6	New
Nokhan1	Kermanshah	2.2	7.4	New
Taleqhan Rood	Tehran	2.5	14.9	New

Source: IWPCO[17]

RENEWABLE ENERGY POLICY

The Renewable Energy Organization of Iran (SUNA) was established in 1996 to evaluate the county's renewable energy potential, to implement renewable energy projects and to guarantee the purchase of any electricity generated from renewable sources in order to attract private sector participation in this field. Subsequently, SUNA became tasked with all matters related to renewable energy and energy efficiency.[20] In 2017, responsibility for implementing the country's renewable energy plan was transferred to the Renewable Energy and Energy Efficiency Organization (SATBA), an organization operating directly under MOE and endowed with additional power and financial resources.[21] One of the key responsibilities of SATBA is facilitating the influx of foreign investment into the renewable energy infrastructure of Iran, accomplished in part through the Foreign Investment Promotion and Protection Act (FIPPA). The Act provides mechanisms for profit transfers abroad and dispute resolution, protections against expropriation or nationalization of assets and support in acquiring visas and work permits for foreign nationals, among other provisions.[22]

The Government has been pushing for a shift away from the use of fossil fuels for electricity generation, which would allow freeing up oil and gas resources for export and ensuring more cost-effective electricity production. In the Fifth Five-Year Development Plan (2010–2015), the Government of Iran announced plans to install 5,000 MW of renewable energy (wind and solar power) by providing incentives, such as minimum tariff rates, for private investment in the sector. However, this target was too ambitious considering the relative state of development of the renewable energy sector in Iran at the time. Implementation was also set back by the impact of international sanctions and unilateral coercive measures. The Sixth Five-Year Development Plan (2016–2020) extended the date for the original 5,000 MW renewable energy target to 2020, and stipulated the development of an additional 2,500 MW of renewable capacity by 2030. The Iranian Power Generation, Transmission, Distribution and Management Company (TAVANIR), estimated that by 2021 the country's renewable energy capacity would be able to meet 10 per cent of the total energy demand.[20]

According to the announcement of the Minister of Energy dated 8 May 2016, electricity consumers can produce their own electricity using rooftop photovoltaic panels of up to 100 kW and small wind turbines of up to 1 MW. The generated electricity can be fed into the distribution grid limited to the connection capacity. Producers can refer to their electrical distribution company and sign a Power Purchase Agreement based on specified tariffs (Table 4), which are guaranteed for a 20-year period.[23] Starting from the first day of the second 10-year period and until the end of the contract, all tariffs except those for wind power plants will be multiplied by 0.7; for wind power plants with a capacity factor of 40 per cent or more, the tariff will be multiplied by 0.4; for wind power plants with a capacity factor of 20–40 per cent, by an appropriate coefficient; and for wind power plants with a capacity factor of below 20 per cent, the tariff will remain the same. Additionally, the tariffs will be adjusted annually based on currency exchange rate fluctuations and retail prices for products. Tariffs can be increased up to a maximum of 30 per cent based on the level of use of local know-how, design and manufacturing in construction. A transmission service rate, announced by Iran Grid Management Company, will be added to the payment tariff for power plants connected to the distribution grid.[24]

Table 4. **Guaranteed Renewable Energy Purchase Tariffs in Iran**

Technology type	*Guaranteed electricity purchase tariff (IRR/kWh (USD/kWh))*
Biomass: landfill	4,050 (0.10)
Biomass: other biochemical processes	5,250 (0.12)
Biomass: all thermal processes	5,550 (0.13)
Geothermal power (including excavation and equipment)	6,370 (0.15)
Electricity generation from waste heat recovery in industrial processes	3,770 (0.09)
SHP (≤ 10 MW): installations on rivers or streams	4,940 (0.12)
SHP (≤ 10 MW): installations on pipelines and side facility of dams (dam and transmission lines)	4,225 (0.10)
Fuel cell systems	6,432 (0.15)
Turbo expanders	2,080 (0.05)
Wind power: ≤ 10 MW	5,460 (0.13)
Wind power: ≤ 1 MW	7,410 (0.18)
Solar power: ≤ 10 MW	6,370 (0.15)
Solar power: ≤ 100 kW	9,100 (0.22)
Solar power: ≤ 20 kW	10,400 (0.25)

Source: SATBA[24]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Water resources in Iran are utilized according to governmental water laws and nationalization plans initiated in 1968. The 1968 Iran Water Law and the Manner of Water Nationalization provided for licensing, duties, water charges and dues, water rights and use permits, as well as for the nationalization of river basins and other water resources and the public use of water resources.[25] More recent pieces of legislation regulating water resources in Iran have included the Law on Equitable Distribution of Water Resources (1983), Strategies for Long-Term Development of the Water Resources of the Country (2003) and the Regulation on Creation of a Balance between Water Resources and Water Use (2008), among others.[26]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change is expected to have considerable impacts on the future productivity of hydropower in Iran. In parallel with the temperature and precipitation fluctuations described earlier, significant decreases in runoff are projected for the 2015–2030 period relative to the period 1982–2009. In particular, the Bandar Abbas-Sedij, Karkheh and Karoun River basins are expected to undergo reductions in runoff of 66, 61 and 55 per cent, respectively.[4] In the case of the Karkheh River basin, the third largest in Iran and representative of other basins in the region, numerical modelling of the impact of various climate change scenarios on the productivity of currently operational hydropower plants across three time periods — 2020s, 2050s and 2080s — suggests a reduction in annual generation of 15–24 per cent in the latter two periods, relative to historical data, and an up to 36 per cent reduction in generation during springtime.[27]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The barriers to the development of SHP in Iran as described in the *WSHPDR 2019* still persist and include:

- Limited water resources and future adverse impacts of climate change;
- A greater focus on the development of medium and large hydropower plants;
- Lack of investment delaying the realization of some projects.

-
- Factors enabling SHP development in the country include:
- Recent reorganization in MOE, which is expected to benefit renewable energy development in general, especially in regard to foreign investment in such projects in Iran;
- Existence of feed-in tariffs for SHP that additionally factor in bonus payments for the use of local know-how and equipment in construction.

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28.

Nepal

Madhu Prasad Bhetuwal and Sunil Poudel, Ministry of Energy, Water Resource and Irrigation

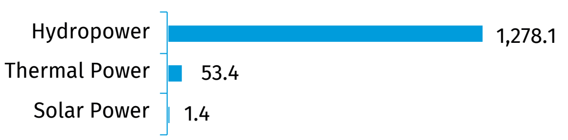
KEY FACTS

Population	30,541,477 (2021)[1]
Area	147,181 km^2 [2]
Topography	The territory of Nepal can be divided into three topographic regions. In southern Nepal lies the Terai plain. The second and largest region of Nepal is formed by the Mahabharat, Churia and Himalayan Mountain Ranges, which extend from east to west. The third region, known as the Kathmandu Valley or the Valley of Nepal, is a high central region, located between the main Himalayan and Mahabharat ranges. The highest peak is Mount Everest (Sagarmatha), at 8,848.86 metres.[2]
Climate	Influenced by the maritime and continental factors, the climate of Nepal has four distinct seasons. Spring (March to May) is warm, with showers and temperatures averaging 22 °C. Summer (June to August) is the monsoon season, with temperatures up to 30 °C. Autumn (September to November) is cool, with clear skies and temperatures reaching a maximum of 25 °C and a minimum of 10 °C. Winter (December to February) is cold, with temperatures sometimes below 0 °C at night.[3]
Climate Change	A gradual rise in maximum temperatures across Nepal has been observed between 1974 and 2014, with an average annual rise of 0.056 °C nationwide and reaching 0.12 °C in certain mountain regions during the winter season. Meanwhile, some lowland regions have experienced a slight decrease in maximum temperatures and an associated increase in the duration of fog episodes. The duration of warm spells and the number of warm days has also seen an increasing trend. Projections of climate change in Nepal predict an increase in average annual temperatures of 0.92–1.07 °C between 2016 and 2045 and of 1.3–1.8 °C between 2036 and 2065, relative to the 1981–2010 baseline period.[4]
Rain Pattern	Mean annual rainfall ranges from 250 mm in north-central Nepal, near the Tibetan plateau, to above 5,000 mm on the southern slopes of the Annapurna Range in central Nepal. Approximately 80 per cent of rainfall occurs in the monsoon period from June to September. Snowfall is confined to the northern and western mountainous regions, especially at elevations above 3,500 metres. The contribution of snow to precipitation is approximately 10 per cent of total rainfall.[3]
Hydrology	There are approximately 6,000 rivers in Nepal with a catchment area of 194,471 km^2, of which 74 per cent lies in Nepal. The rivers can be broadly divided into three categories according to their origin. The first category comprises the four main river systems of the country: the Koshi, Gandaki, Karnali and Mahakali River systems, all of which originate from glaciers and snow-fed lakes. These are perennial rivers with a significant flow even during the dry season. Rivers originating from the Mahabharat Range or midlands, such as the Babai, West Rapti, Bagmati, Kamala, Kankai and Mechi Rivers, are fed by precipitation and groundwater. These rivers are perennial but with little flow during the dry season. Streams and rivulets originating mostly from the Chure hills make up the third category. These rivers rely on monsoon rains and are otherwise dry. The first and second category of rivers have a high potential for hydropower development.[2]

ELECTRICITY SECTOR OVERVIEW

The installed capacity of Nepal was 1,332.9 MW as of mid-2020, with large and small hydropower (SHP) providing 1,278.1 MW (96 per cent) of the total, thermal power, including diesel and multi-fuel power plants, providing 53.4 MW (4 per cent) and solar power 1.4 MW (less than 1 per cent) (Figure 1). Nearly 46 per cent (581.9 MW) of the installed capacity of hydropower in the country is owned by the Nepal Electricity Authority (NEA), while the remaining 54 per cent (696.2 MW), comprising mostly run-of-river SHP plants, is owned by independent power producers (IPPs).[5]

Figure 1. **Installed Electricity Capacity by Source in Nepal in 2020 (MW)**



Source: NEA[5]

Electricity generation in the 2019/2020 fiscal year reached 6,012 GWh, provided almost exclusively by hydropower, with generation from other sources being negligible. Hydropower plants owned by the NEA provided 3,021 GWh (50 per cent) of this total, while those owned by IPPs provided an additional 2,991 GWh (50 per cent). While imports from India equalled 1,729 GWh, representing a nearly 39 per cent decline relative to the previous fiscal year, total electricity available in the grid reached 7,741 GWh, increasing slightly from the 7,551 GWh during the previous fiscal year (Figure 2).[2]

Figure 2. **Electricity Supply in Nepal in 2019/2020 (GWh)**

Source: NEA[5]

Electricity consumption during the 2019/2020 fiscal year equalled 6,422 GWh, while peak power demand reached 1,408 MW. Consumption was dominated by the domestic and industrial sectors, at 2,867 GWh and 2,286 GWh purchased, respectively. The nationwide rate of electricity access in Nepal was 90 per cent in 2020, but per-capita electricity consumption remains very low at 267 kWh per year.[6,7]

Transmission and distribution losses equalled over 15 per cent in 2019/2020, but showed a slight decrease relative to the previous fiscal year as a result of the continuous efforts by the NEA to improve the electricity grid. The national grid consisted of 78 circuit kilometres (ckm) of 400 kV lines, 178 ckm of 220 kV lines, 3,037 ckm of 132 kV lines and 514.5 ckm of 66 kV lines as of mid-2020. Total capacity of grid substations was 6,305 MVA. To enhance and expand transmission capacity, the Government of Nepal launched several initiatives, including study and construction of transmission lines of different voltages as well as of additional substations. As of mid-2020, 576 ckm of 400 kV lines, 584 ckm of 220 kV lines and 1,176 ckm of 132 kV transmission lines were under construction. The total lengths of distribution lines of 33 kV, 11 kV and 400/230 V were 5,552 ckm, 39,522 ckm and 122,117 ckm, respectively. In addition to the country's installed capacity, power is also being imported from India via 11 cross-border transmission lines at different voltages; five at 33 kV, five at 132 kV and one at 400 kV.[5,8]

Following the signing of the Electric Power Trade, Cross Border Transmission Interconnection and Grid Connectivity Agreement win India in 2014, the Joint Technical Team of Nepal and India formulated the Integrated Transmission Master Plan, paving the way for electricity exports from Nepal to India from power plants that are expected to become operational by 2035. In parallel, a domestic Transmission System Development Plan has been prepared by the Government of Nepal to account for the added capacity expected to come into operation by 2040.[9]

Ten years of internal conflict left their mark on the electricity sector of the country. Nepal faced a severe power crisis as planned projects were not commissioned on time. Despite having a very significant hydropower potential (83 GW of theoretical and 43 GW of economically feasible potential), Nepal has been importing electricity from India to meet its growing domestic demand.[6] The earthquake in April 2015 also severely affected the electricity system of the country, with at least 150 MW of hydropower installed capacity damaged. Due to the nature of the earthquake and the landslides it caused, mini- and micro-hydropower plants located in the mountainous regions were particularly affected, resulting in at least 45 MW of damaged capacity.[10] As of 2018, most of these plants were back in operation after having been non-functional for approximately 1–2 years. Furthermore, 219 new hydropower projects were under construction as of 2021 that would add some 8,321 MW of new capacity to the national grid within over the next five years. Surveys are being carried out to prepare feasibility studies for an additional 268 projects with a combined capacity of 24,982 MW.[11]

To expedite the development of the power sector in the country, on 18 February 2016 the Government of Nepal approved "The National Energy Crisis Management and Concept Paper for the Electricity Development Decade", which included a SWOT (Strengths, Weaknesses, Opportunities and Threats) analysis of the power sector. Various reforms of the sector have been proposed, covering such aspects as the organizational, legal and administrative system, power purchase, electricity distribution, theft control and investment procedure, in order to accelerate private investments as well as to enhance the efficiency and effectiveness of public entities engaged in the power sector.[12] The proposals included simplifying working procedures in awarding licences, procuring private land or leasing Government land including forest land, establishment of Rastriya Prasharan Grid Company, Generation Company, steering committees at different levels to resolve disputes that may arise while implementing projects, setting electricity tariff rates for different types of projects (run-of-river, peaking run-of-river, storage and solar power plants) and mitigating foreign currency exchange risk. In order to increase energy security, provisions have been made to develop storage and alternate energy resources projects, including solar power and wind power plants.[8]

Key institutions operating in the power sector of Nepal include the Ministry of Energy, Water Resources and Irrigation (MoEWRI), the Department of Electricity Development (DoED), the Alternate Energy Promotion Centre (AEPC), the Investment Board of Nepal (IBN), the Nepal Electricity Authority (NEA), the Electricity Regulatory Commission (ERC) and IPPs. The MoEWRI, DoED, AEPC and IBN play facilitating roles in the power sector, while the ERC acts as the national power sector regulator. The state-owned NEA and IPPs are both responsible for the power generation sector, while the NEA is additionally responsible for most transmission, distribution, scheduling, dispatch and sales of electricity. The private sector has participated in the electricity market of Nepal since 1992, under the Hydropower Development Policy issued the same year. One large privately-owned distribution company, Butwal Power Company, supplies electricity to 50,000 consumers. In addition, there are many community-managed distribution schemes scattered across the country.[13]

Legislation regulating the power sector in Nepal is continuously refined based on experiences applying the Build-Own-Operate-Transfer (BOOT) model in power projects, international best practices and the emergence of new technologies. The Electricity Bill, 2020, recently submitted for parliamentary approval, includes mechanisms and procedures to enhance transparency, promote competition and minimize inefficiencies in the power sector in order to deliver reliable and secure electricity at affordable prices. Similarly, the National Water Resources policy approved on 13 July 2020 includes provisions to harmonize water use among various stakeholders at the national, provincial and local levels.[8]

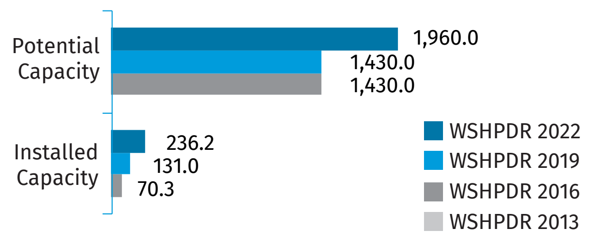
Electricity tariffs for domestic consumers in Nepal include 230 V single-phase low-voltage connections, 400 V three-phase low-voltage connections and 33/11 kV three-phase medium-voltage connections. Single-phase low-voltage tariffs vary according to monthly consumption (kWh/month) and connection amperage (5/15/30/60 A) and are composed of a minimum monthly charge and an energy consumption charge. In 2020, minimum monthly charges ranged between 30 NPR/month and 275 NPR/month (0.25-2.30 USD/month) and consumption charges ranged between 0 NPR/kWh (0 USD/kWh) for consumption under 10 kWh/month and 12 NPR/kWh (0.10 USD/kWh) for the highest consumption category.[5]

SMALL HYDROPOWER SECTOR OVERVIEW

Nepal generally adheres to the definition of SHP as hydropower plants with a capacity of up to 25 MW. However, it is not clearly defined in government policy or legal documents.

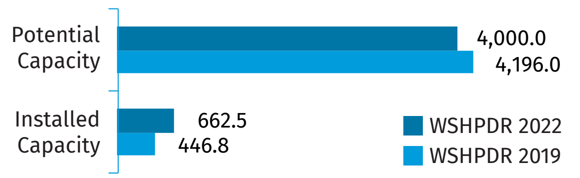
As of April 2021, the installed capacity of SHP up to 25 MW in Nepal was 662.5 MW from 85 plants, predominantly composed of plants with an installed capacity of up to 10 MW. The potential capacity of SHP up to 25 MW is estimated at approximately 4,000 MW, based on projects that have submitted licence applications as well as those on the Government's reserve list.[11] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP up to 25 MW in Nepal has increased by 48 per cent due to the construction of new SHP plants, while the estimated potential capacity decreased by 5 per cent, based on more accurate data (Figure 3).[14] No current data on the installed or potential capacity of SHP up to 10 MW is available (Figure 4).

Figure 3. **Small Hydropower Capacities up to 25 MW in the WSHPDR 2019/2022 in Nepal (MW)**



Source: DoED,[11] *WSHPDR 2019*[14]

Figure 4. **Small Hydropower Capacities up to 10 MW in the WSHPDR 2013/2016/2019 in Nepal (MW)**



Source: *WSHPDR 2019*,[14] *WSHPDR 2013*,[15] *WSHPDR 2016*[16]

The total number of SHP projects that have received generation licences stood at 159 as of April 2021, with a total proposed capacity of approximately 2,001 MW. Meanwhile, 14 projects totalling 125 MW had applied for a construction licence and 153 projects totalling 1,839 MW had been granted licences for the preparation of feasibility studies and environmental impact assessments. Finally, several additional SHP projects are currently under study.[11] The majority of existing and planned SHP capacity is connected to the national grid, but approximately 3,000 micro-hydropower plants with a total installed capacity of 35 MW are off-grid and provide power to rural and isolated areas.[17] Some recently commissioned SHP plants in Nepal are listed in Table 1, while several ongoing projects are listed in Table 2.

Table 1. **List of Selected Existing Small Hydropower Plants in Nepal**

Name	*Location (River)*	*Capacity (MW)*	*Type of plant*	*Operator*	*Launch year*
Rawa Khola	Rawa Khola	3.00	Run-of-river	Rawa Energy Development Pvt Ltd	2020
Super Mai-A	Mai Khola	9.60	Run-of-river	Sagarmatha Jalbidhyut Company Pvt. Ltd.	2020
Super Mai Khola Cascade	Mai Khola	3.00	Run-of-river	Mai Khola Hydropower Pvt.Ltd.	2020
Ghalemdi Khola	Ghalemdi	5.00	Run-of-river	Ghalemdi Hydro Limited	2019
Kapadigad	Kapadigad	3.33	Run-of-river	Salmanidevi Hydropower Pvt Ltd	2019

Name	*Location (River)*	*Capacity (MW)*	*Type of plant*	*Operator*	*Launch year*
Solu	Solu Khola	23.50	Run-of-river	Upper Solu Hydroelectric Company Pvt Ltd	2019
Iwa Khola	Iwa Khola	9.90	Run-of-river	Rairang Hydropower Development Co Ltd	2019
Upper Khorunga	Khoranga Khola	7.50	Run-of-river	Terhathum Power Company Pvt. Ltd.	2019
Upper Naugad Gad	Naugad	8.00	Run-of-river	Api Power Company Ltd.	2019
Upper Mardi	Mardi	7.00	Run-of-river	United Idimardi and R.B. Hydropower Pvt Ltd	2019
Rudi Khola-B	Rudi Khola	6.60	Run-of-river	Bindhyabasini Hydropower Development Co. Pvt Ltd	2019
Padam Khola	Padam Khola	4.80	Run-of-river	Dolti Power Company P. Ltd	2019
Rudi A	Rudi Khola	8.80	Run-of-river	Bindhabasini Hydropower Development Company Pvt.Ltd	2018
Bagmati Nadi	Bagmati	22.00	Run-of-river	Mandu Hydropower Pvt. Ltd.	2018
Theule Khola	Theule	1.50	Run-of-river	Barahi Hydropower Pvt Ltd	2018
Super Mai	Mai Khola	7.80	Run-of-river	Supermai Hydropower Pvt.Ltd.	2018
Madkyu Khola	Madkyu	13.00	Run-of-river	Silkes Hydropower Pvt.Ltd	2017
Chake Khola	Chake Khola	2.83	Run-of-river	Garjang Upatyaka HP Company Limited	2017
Dwari Khola	Dwari	3.75	Run-of-river	Bhugol Energy Development Company Pvt Ltd	2017
Molun Khola	Molun	7.00	Run-of-river	Molun Hydropower Co. Pvt. Ltd	2017

Source: DoED[11]

Table 2. **List of Selected Ongoing Small Hydropower Projects in Nepal**

Name	*Location (River)*	*Capacity (MW)*	*Type of plant*	*Developer*
Langdi Khola	Langdi	3.26	Run-of-river	Ujyalo Nepal Hydro Pvt. Ltd.
Upper Daraudi	Daraudi	9.20	Run-of-river	Green Gorkha Energy Limited
Upper Ingwa Khola	Ingwa	9.70	Run-of-river	Ingwa Hydopower Pvt. Ltd.,
Setikhola	Seti Khola	22.00	Run-of-river	Setikhola Hydropower Pvt.Ltd.
Mewa Khola	Mewa Khola	23.00	Run-of-river	Union Mewa Hydro ltd

Source: DoED[11]

Note: Data as of 2021.

In general, Nepal views hydropower development as an important means for enabling economic growth and human development, as well as for overcoming the imbalance between demand and supply and keeping pace with the growth of annual demand. There is huge potential for the development of SHP projects in Nepal with an attractive rate of return. Several SHP projects available for investment are displayed in Table 3.

Table 3. **List of Selected Small Hydropower Projects Available for Investment in Nepal**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Developer*
Hidi Khola	Lamjung	6.80	Run-of-river	North Summit Hydro Pvt. Ltd.
Upper Irkhuwa	Bhojpur	14.50	Run-of-river	Arati Power Company Ltd.
Middle Trishuli Ganga	Nuwakot	19.41	Run-of-river	Perfect Energy Development Pvt. Ltd
Mewa Khola	Taplejung	23.00	Run-of-river	Union Mewa Hydro Ltd.
Madame Khola	Kaski	24.00	Run-of-river	Madame Khola Hydropower Pvt. Ltd.

Source: IPPAN[18]

Note: Data as of 2021.

RENEWABLE ENERGY POLICY

In 2011, the Government of Nepal launched the National Rural and Renewable Energy Programme (NRREP), which aimed to scale up energy access in rural areas through renewable energy sources (RES). In 2016, the Government of Nepal adopted the Renewable Energy Subsidy Policy, which aims to foster the development of the renewable energy sector and support low-income households in using renewable energy technologies through subsidies. In particular, subsidies for micro- and mini-hydropower facilities range from NPR 20,000 to NPR 125,000 (USD 167 to USD 1,042) per kW for generation and from NPR 28,000 to NPR 35,500 (USD 233 to USD 296) per household for distribution.[19]

As of the end of the fiscal year 2019/2020, approximately 10 per cent of the total population had access to electricity from RES, while 36 per cent of the population were using clean renewable energy for various purposes.[6]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The Electricity Act (1992), the Electricity Regulation (1993) and the Water Resources Act (1992) are the key legal documents that paved the entry of the private sector into the development of power projects. A licence is required for conducting preliminary investigations for projects of 1 MW capacity or more. For projects of below 1 MW capacity, this requirement is waived by provisions contained in the Electricity Act (1992), provided the project is registered with the District Water Resources Committee and forwarded to the DoED.

There is a two-stage licensing system. The first stage is a survey licence issued for a maximum of five years to carry out feasibility and environmental studies. The second stage is a generation licence granted for a set term for the construction and operation of a power plant. At the end of the term, the licensee is required to transfer the project to state ownership free of charge and in a good operating condition. The Hydropower Development Policy (2001), aiming to improve nationwide electricity access through the development of affordable and efficient hydropower, updated the duration of generation licences to 35 years for domestic projects and 30 years for export-oriented projects.[20,21]

COST OF SMALL HYDROPOWER DEVELOPMENT

The cost of SHP development in Nepal includes the costs of civil engineering, metal works, plant machinery, installation of transmission lines and switch yard, land purchase and development, purchase/operation of vehicles, environment and social mitigation, project supervision, insurance and other miscellaneous costs. The average cost of development per installed MW is approximately NPR 200 million (USD 1.67 million), with a breakdown of costs provided in Table 4.[8]

Table 4. **Average Costs of Small Hydropower Development in Nepal**

Particulars	*Cost per MW in (NPR (USD)*	*Share of total cost*
Licence and study cost	5,000,000 (42,000)	3%
Construction/installation cost	140,000,000 (1,170,000)	70%
Land, infrastructure and management, social mitigation, insurance	20,000,000 (170,000)	10%
Contingency	10,000,000 (83,000)	5%
Finance cost (IDC)	25,000,000 (210,000)	13%
Total	**200,000,000 (1,670,000)**	**100%**

Source: Bhetuwal & Poudel[8]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Nepal has abundant opportunities for financing of SHP projects as this sector is given special priority in the country. The Ministry of Industry, Commerce and Supply, the MoEWRI and the Office of IBN are several of the many government institutions involved in facilitating foreign and domestic investment in SHP. Domestic or foreign investors can finance SHP projects and mixed foreign-domestic financing of projects is also possible. However, domestic investment is prevalent. Loans raised for SHP projects typically come from banks/financial institutions, while the equity is raised by the promoter through public shares. In general, the debt-to-equity ratio is maintained at 70:30. The payback period from SHP operation is typically 7–10 years, while the loan repayment period is typically set at 8–12 years and begins at the start of commercial operation.

In order to gain access to domestic financing options, investors must typically conclude a power purchase agreement (PPA) with the NEA. The PPA electricity purchase rate set by NEA for run-of-river SHP projects is as follows:

- Energy generated during the rainy season (June to November) must reach at least 70 per cent of theoretical generation capacity of the plant and is purchased at 4.8 NPR/kWh (0.04 USD/kWh);
- Energy generated during the dry season (December to May) must reach at least 30 per cent of theoretical generation capacity of the plant and is purchased at 8.4 NPR/kWh (0.07 USD/kWh);
- The given rate has a 3 per cent simple escalation for a period of eight years.[8]

Additionally, the Government of Nepal provides various tax exemptions and other incentives for SHP developers. These include a 1 per cent cap on customs duties, a 100 per cent income tax exemption for the first 10 years of operation and thereafter a 50 per cent income tax exemption for another 5 years and a value-added tax (VAT) exemption on the purchase of electromechanical equipment and parts for SHP plants.[8]

At the same time, the developer is obligated to pay royalties to the Government for operation of SHP plants. The royalty mechanism applies to SHP plants with an installed capacity over 1 MW and includes an annual capacity royalty of 100 NPR/kW (0.85 USD/kW) and a generation royalty of 2 per cent of the sale price per kWh sold for the first 15 years of operation as well as a capacity royalty of 1,000 NPR/kW (8.51 USD/kW) and generation royalty of 10 per cent per kWh sold for every subsequent year of operation.[8]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The impact of the climate crisis on SHP generation and development in Nepal include wider disparity between seasonal distribution of rainfall and runoff. During the winter season, projected decreases in precipitation and runoff are likely to lead to reductions in hydropower generation. With electricity demand likewise peaking during the winter, increased load shedding and electricity imports from India will likely be necessary. During the rainy season, an increase in runoff and extreme rainfall is expected according to climate models. With the overwhelming majority of SHP plants in Nepal being of the run-of-river type, floods and heavy sediment inflow are likely to cause damage to hydropower structures and increase the operation and maintenance cost of SHP plants in particular.

Climate policy in Nepal with regard to SHP must focus on adaptation measures, including promoting structural designs for SHP plants that account for expected extreme weather impacts. Riverside power facilities should be more robust than has been typically practiced in recent development to cope with future climate-induced flooding. Additionally, SHP plants need to be designed to better cope with low flow and be able to continue generating electricity even under drought conditions. Additional adaptation measures should include careful site selection for SHP in locations less vulnerable to extreme weather impacts, better insurance policies and the development of an early warning system for floods and landslides to reduce damage to SHP structures.[8]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

While there has been extensive growth of SHP in Nepal over the past 50 years, there remain several limiting factors to SHP development. Some of the principal barriers include:

- Lack of clear and supportive policies and a regulatory framework;
- Political instability;
- Limitations on bank financing: unattractive loan duration and interest rates as banks are unable to raise long-term borrowings, inability to hedge the exchange risk as lending is in USD but the income stream is in NPR;
- Ineffective licensing procedure;
- No single agency fully empowered to serve the SHP sector;
- Poor or non-existent access to infrastructure or power evacuation lines;
- The burdensome procedure of carrying out an environmental impact assessment may lead to delays in the implementation of projects;
- Additional financial burden on NEA during certain periods of the year resulting from underutilization of its own power plants while being forced to absorb power from SHP plants due to take-or-pay PPAs;
- Limited domestic demand; only one off-taker, NEA, often unwilling to sign PPAs;
- Issues with legal enforcement of contracts;
- High sedimentation rate requiring large desanders or additional maintenance to repair turbines;
- Inconsistent policies;
- Low load factors of SHP plants and their inability to deliver energy during the dry season;
- Absence of integrated river basin plans;
- Growing expectations of local people towards hydropower projects due to the compensation amount for the land acquired by the developers being 4 to 10 times higher than the market price;
- Weak geology requiring more investment in the slope protection and tunnelling;
- Hydrological uncertainties due to climate change.

At the same time, several enabling factors for further SHP development in Nepal do exist, including the following:

- Availability of skilled manpower for the design and construction of SHP projects;
- Availability of domestic financing;
- Availability of multiple projects in various stages of planning requiring additional investment;
- Incentives and tax exemptions for developers.

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Pakistan

Ejaz Hussain Butt, SMEC-EGC; Adnan Ghafoor, PPDB

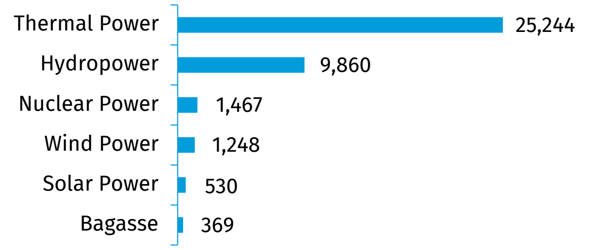
KEY FACTS

Population	215,250,000 (2021)[1]
Area	803,940 km^2 [2]
Topography	Pakistan exhibits a blend of landscapes varying from plains to deserts, forests, hills, plateaus, coastal areas of the Arabian Sea in the south and the mountains of Karakoram and Himalayan ranges in the north. The world's second and ninth highest peaks, K-2 (8,611 metres) and Nanga Parbat (8,126 metres) are located in the northernmost parts of Pakistan.[3]
Climate	The climate is dry and hot in plain lands, becoming progressively cooler towards the north-eastern highlands. In Islamabad, the capital city, hot season begins in March and by June temperatures may reach up to 46 °C, while the cold season lasts from December to February, when the temperature may drop below -3 °C. In the northernmost parts of the country, winter temperatures may fall below -10 °C.[2]
Climate Change	The foreseen effects of climate change in Pakistan include increased variability of monsoons, the likely receding of the Hindu Kush-Karakoram-Himalayan glaciers due to temperature increase and carbon soot deposits from transboundary pollution sources, which will threaten water inflows into the Indus River system. Other risks include severe water shortages, particularly in arid and semi-arid regions, decreasing forest cover and increased level of saline water in the Indus delta. In the last 50 years, the annual mean temperature in Pakistan has increased by roughly 0.5 °C and variability in annual precipitation has increased. The number of heatwave days per year has increased nearly fivefold in the last 30 years. The sea level along the Karachi coast has risen by approximately 10 cm in the last century and is expected to rise by a further 60 cm by the end of the century. By the end of this century, the annual mean temperature in Pakistan is expected to rise by 3-5 °C for the central global emissions scenario, while higher global emissions may yield a rise of 4-6 °C. Average annual rainfall is not expected to have a significant long-term trend, but is expected to exhibit large interannual variability, an example of which is a cloudburst that occurred in 2001 resulting in 620 mm of rainfall recorded over 12 hours in Islamabad.[4]
Rain Pattern	The distribution of rainfall in Pakistan varies greatly, mostly associated with monsoon winds and the western disturbances. Precipitation is not continuous throughout the year and also varies from year to year. Between June and September, the monsoon provides an average rainfall of approximately 38 mm in the river basins and up to approximately 150 mm in the north. In some areas, high volumes of rainfall can cause floods, while in desert areas low rainfall can cause droughts.[3,5]
Hydrology	The main surface water resources of Pakistan are represented by the Indus River and its tributaries. The Indus River has a total length of 3,780 km, with a drainage basin of approximately 1,165,000 km^2. Its main tributaries are the Jhelum, Chenab, Ravi, Beas and Sutlej. Most groundwater resources exist in the Indus Plain, extending from the Himalayan foothills to the Arabian Sea, and are stored in alluvial deposits. The plain is approximately 1,600 km long, covers 210,000 km^2 and has an extensive unconfined aquifer, which is fast becoming the supplemental source of water for irrigation. Mean annual availability of surface and groundwater is approximately 170,000 million m^3 and 71,000 million m^3, respectively.[6]

ELECTRICITY SECTOR OVERVIEW

In mid-2020, the total installed capacity of Pakistan under the control of the National Transmission and Distribution Company (NTDC) was 38,719 MW. Thermal power accounted for approximately 64 per cent of total installed capacity, hydropower for 26 per cent, nuclear power for 4 per cent, wind power for 3 per cent, solar power for slightly more than 1 per cent and biomass for 1 per cent (Figure 1).[7] Hydropower and thermal power sources have been used for much of the country's history, with plants being mainly located in the northern parts of the country and a few in the plains. The generation of electricity from nuclear power, solar power, wind power and other alternative sources has begun rather recently. As a result, the number and capacities of these plants are smaller than those of thermal and hydropower plants.[7]

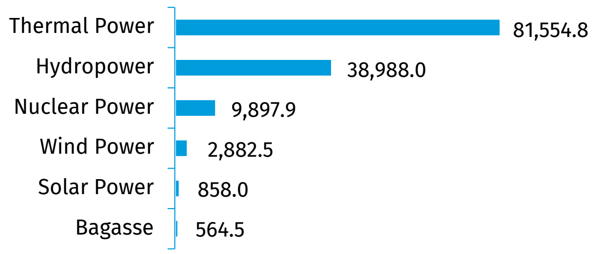
Figure 1. **Installed Electricity Capacity by Source in Pakistan in 2020 (MW)**



Source: NEPRA[7]

In terms of electricity generation, out of the total of 134,746 GWh generated in 2019–2020, almost 61 per cent came from thermal power, 29 per cent from hydropower, 7 per cent from nuclear power, 2 per cent from wind power and less than 1 per cent from bagasse and solar power each (Figure 2). An additional 514 GWh was imported from Iran.[7]

Figure 2. **Annual Electricity Generation by Source in Pakistan in 2019–2020 (GWh)**



Source: NEPRA[7]

At the end of 2020, there were over 575,000 kilometres of transmission lines and 999 grid stations of various capacities in service.[8] The total number of electricity consumers was 32.9 million and the total number of villages electrified was 157,203.[7] In 2019, approximately 74 per cent of the population of Pakistan had access to electricity.[9]

Prior to 1998, there were two vertically integrated utilities, the Karachi Electric Supply Company (KESC), which served the Karachi area, and the Pakistan Water and Power Development Authority (WAPDA), which served the rest of the country and was the largest public power generating company owning more than 59 per cent of the country's generating capacity and serving the majority of consumers. The power sector was restructured in 1998 with the creation of PEPCO (Pakistan Electric Power Company). WAPDA's power division was restructured into distinct corporate entities comprising four generation companies (GENCOs), 10 distribution companies (DISCOs) and the National Transmission and Distribution Company (NTDC). A small share of power distribution has been undertaken by K-Electric (formerly KESC) serving electric power in Karachi, the biggest city of Pakistan.[10]

The National Electric Power Regulatory Authority (NEPRA) is the country's sole authority that determines and fixes the tariffs for all types of generating plants and electricity consumers (domestic, commercial and industrial). Peak and off-peak tariffs are charged to industrial consumers and now to domestic consumers as well. The average household electricity tariff paid in Pakistan in 2020 was approximately 0.14 USD/kWh.[7]

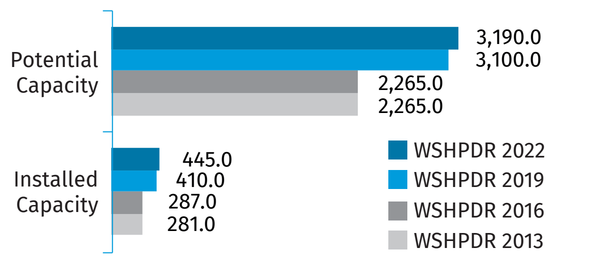
In Pakistan, a large part of the current decade was plagued with excessive load-shedding due to non-availability of sufficient affordable generation capacity and inefficient transmission and distribution services. With the introduction of a substantial amount of generation capacity during the last few years, the availability of electricity has improved significantly but the cost of electricity for end-consumers has increased owing to various reasons, such as high transmission and distribution losses, low recovery, circular debt, huge capacity payments, currency devaluation, fuel cost and underutilization of efficient power plants.[10]

SMALL HYDROPOWER SECTOR OVERVIEW

In Pakistan, two types of classification of small hydropower (SHP) exist. Under the Renewable Energy Policy of 2006, SHP plants were classified as those under or equal to 50 MW. In 2015, following NEPRA's determination of the upfront tariff for SHP projects, the definition of 25 MW and below was introduced.

In this chapter, based on the above categorization, the benchmark for SHP is taken as 50 MW. The installed capacity of SHP according to this definition was 445 MW as of 2020, generating 1,900 GWh annually. Total estimated potential is approximately 3,190 MW, indicating that some 14 per cent of the country's SHP potential has been developed.[11,12,13,14,15,16] Compared to the results of the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity increased by nearly 9 per cent, while estimated potential capacity increased by approximately 3 per cent (Figure 3). The increase in installed capacity was due to several new SHP projects commissioned in recent years.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Pakistan (MW)**



Source: AEDB,[11] WAPDA,[12] Qureshi & Akıntuğ,[13] PPIB,[14] SMEC-EGC,[15] *WSHPDR 2013*,[16] *WSHPDR 2016*,[17] *WSHPDR 2019*[18]

Note: Data for SHP up to 50 MW.

Of the total installed hydropower capacity of Pakistan, SHP accounts for almost 5 per cent, while the SHP potential is approximately 5 per cent of the total hydropower potential (approximately 60,000 MW).[13] The north of Pakistan is rich in hydropower resources. Numerous SHP projects have already been developed (Table 1) and many are under implementation (Table 2) or have been identified in preliminary hydropower potential studies of various river basins (Table 3). The province of Gilgit-Baltistan has the greatest installed capacity and the largest potential, while in Baluchistan the potential is negligible due to the region's very low rainfall.

The major part of development of small and micro-hydropower in Pakistan is being undertaken by the Pakhtunkhwa Energy Development Organization (PEDO), Punjab Power Development Board (PPDB), Alternative Energy Development Board (AEDB) and Pakistan Council of Renewable Energy Technologies (PCRET). PEDO has recently completed a programme of development of 356 off-grid micro-hydropower plants with a total capacity of 35 MW in the high mountainous districts of the Pakhtunkhwa province. A similar programme to develop a further 672 micro-hydropower plants on canal falls (53 MW), with the assistance of the Asian Development Bank (ADB), has been initiated.

PCRET is a pioneering agency in introducing the micro-hydropower technology in Pakistan and serves as the national focal point for the development and dissemination of renewable energy technologies in the country. In particular, PCRET has installed in northern areas more than 560 micro-hydropower plants (less than 200 kW) with a combined capacity of approximately 9 MW to meet the energy demand of more than 80,000 households. PCRET has also developed, installed and tested a cross-flow turbine of 10–50 kW. A China–Pakistan Joint Research Center for SHP and Hydropower Support Workshop have also been established in Islamabad and Peshawar, respectively. Further, the National Hydropower Plant Quality Control and Electromechanical Equipment Testing Center as well as the Hydropower Power Plant Electromechanical Equipment and Allied Accessories Manufacturing Facility are going to be established in Islamabad.

PPDB is encouraging development of SHP projects in the individual power producer (IPP) and captive modes. Recently, PPDB issued a letter of interest for 17 SHP sites with a combined installed capacity of 129 MW for development in the IPP mode. These projects are in different stages of development, overall, their pace of development is slow due to a non-supportive response of the Federal Ministry of Energy and its associated departments. Considering the hurdles in development of SHP projects for the national grid, PPDB has initiated a project for the development in the captive mode of projects of less than 2 MW to supply generated electricity for the self-use of small enterprises with the vision to enhance the development of small industries and increase rural employment. In this regard, the Captive Guidelines for SHP projects have been approved by the Board. As the first phase of the project, the Board has allowed the initiation of 10 SHP projects with an aggregate capacity of 13.55 MW in the captive mode.

The Agha Khan Rural Support Programme (AKRSP) has installed micro- and mini-hydropower plants at Chitral and other places in Gilgit Baltistan.[19] It has launched a strategy programme for priority valleys, with a total of nine projects initiated in 2016. Out of these, six projects have been completed (four in 2016 and two in 2017) and three projects remain under construction (two in Chitral, one in Gilgit). The Immit SHP plant of 300 kW was planned to be completed by the end of 2021 and two projects in Chitral were to be completed in 2018. In addition, two new SHP projects were to be initiated in the last quarter of 2017, with plans for further project development conditional on funding availability. The Swiss Agency for Development and Cooperation (SDC) had funding commitments for two projects and those were completed in 2016. Currently there is no funding availability with SDC for new SHP projects. However, there is great demand and potential for investment in SHP in the program area. All of the 13 SHP plants (including nine in 2016, two in 2017 and two in 2018) directly benefit 49,500 beneficiaries in the region.

Table 1. **List of Selected Operational Small Hydropower Plants in Pakistan**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Jhing I	AJK	14.4	High	Run-of-river	AJK Government	2021
DaralKhwar	Khyber PakhtunKhwa	36.0	High	Run-of-river	KPK Government	2021
Ranolia	Khyber PakhtunKhwa	17.0	High	Run-of-river	KPK Government	2021
Naltar V	Gilgit Baltistan	14.0	High	Run-of-river	Gilgit Baltistan Government	2017
Rasul UJC Hydro	Punjab	35.0	Low	Run-of-river	Punjab Government	1952/2015
Jabban	Khyber PakhtunKhwa	22.0	High	Run-of-river	WAPDA	1952/2013
Satpara	Gilgit Baltistan	17.4	High	Reservoir	WAPDA	2013
Jagran I	AJK	30.4	High	Run-of-river	AJK Government	2011
Pehur	Khyber PakhtunKhwa	18.0	High	Run-of-river	KPK Government	2009
Naltar IV	Gilgit Baltistan	18.0	High	Run-of-river	Gilgit Baltistan	2007
Gilgit	Gilgit-Baltistan	10.6	High	Run-of-river	Gilgit Baltistan Government	1998

Name	Location	Capacity (MW)	Head (m)	Plant type	Operator	Launch year
Nandipur	Punjab	13.8	High	Run-of-river	WAPDA	1963
Shadiwal	Punjab	13.5	Low	Run-of-river	WAPDA	1961
Chicho ki Milan	Punjab	13.2	Low	Run-of-river	WAPDA	1959
Dargai	Khyber Pakhtunkhwa	20.0	High	Run-of-river	WAPDA	1952

Source: WAPDA,[12] AJK PDO,[20] PEDO[21]

Table 2. **List of Selected Planned Small Hydropower Projects in Pakistan**

Name	Location	Capacity (MW)	Head (m)	Plant type	Developer	Planned launch year	Stage of development
Jabori	Khyber Pakhtunkhwa	10.2	High	Run-of-river	KPK Government	2022	Under construction
Jagran II	AJK	48.0	High	Run-of-river	AJK Government	2022	Under construction
Koto	Khyber Pakhtunkhwa	40.8	High	Run-of-river	KPK Government	2022	Under construction
Kurram Tangi Stage-I	Khyber Pakhtunkhwa	18.9	High	Run-of-river	WAPDA	2022	Under construction
Nagdar	AJK	35.0	High	Run-of-river	AJK Government	2022	Under construction

Source: WAPDA,[12] AJK PDO,[20] PEDO[21]

Table 3. **List of Selected Small Hydropower Projects Available for Investment in Pakistan**

Name	Location	Potential capacity (MW)	Head (m)	Type of site (new/refurbishment)
BS Link Tail	Kasur, BS-1	10.5	3	New
Murree	Murree	12.0	136	New
Soan	DohkMarkhel	35.0	10	New

Source: Government of Punjab[22]

RENEWABLE ENERGY POLICY

Although various energy policies implemented by Pakistan between 1985 and 2002 stressed the need for employing renewable energy resources, none provided a framework for the implementation of such projects. A clear road map for the development of domestic renewable resources was virtually non-existent as these policies failed to create private sector confidence and attract investment. In 2002, the Power Policy was adopted, which encouraged the use of local resources, including renewable energy.[23] The policy aimed to develop approximately 500 MW of renewable generation capacity (excluding hydropower) by 2015 and 1,000 MW by 2020.

The Alternative Energy Development Board (AEDB) was established in May 2003 with the main objective of facilitating, promoting and encouraging development of renewable energy in Pakistan. In 2006, AEDB introduced the Policy for Development of Renewable Energy for Power Generation, which became the first policy aiming to promote renewable energy projects in Pakistan. The policy set the goal to achieve a 10 per cent share of renewable energy in the country's energy mix by 2015, specifically focusing on solar power, wind power and SHP projects.[24] The policy aims to harmonize the work of various Government bodies in relation to alternative and renewable energy, introduce incentives to attract investment, optimize the impact of alternative and renewable energy technologies in less developed areas, increase related institutional and technical capacities, promote research and development and create a local base for manufacturing alternative and renewable energy technologies. The policy also set the goal to increase per capita energy consumption while promoting environmental protection and awareness, especially in remote and rural areas where poverty can be alleviated and the burden on women collecting biomass fuel can be reduced. Specific incentives for IPPs of alternative and renewable energy include a simplified generation licensing procedure, simplified land and site access, guaranteed purchase of all power and payment and facilitated acquisition of carbon credits. Since the adoption of the policy, the share of renewable energy in the country's energy mix grew substantially, having reached some 31 per cent by mid-2020, although the sector remained dominated by thermal power.

In April 2015, the Power Generation Policy 2015 was published by the Private Power and Infrastructure Board (PPIB) after its approval by the Council of Common Interests. The main objectives of the policy are to provide sufficient power generation capacity at the least cost, encourage and ensure exploitation of domestic resources, ensure that the interests of all stakeholders are taken into account to create a win-win situation for all and be attuned to safeguarding the environment. The policy deals with private projects, public power projects where required by the project sponsor, public-private partnership (PPP) projects and projects developed by the public sector and subsequently divested.[25]

More recently, the Government released a draft policy on Alternative and Renewable Energy 2019. The policy has an expanded scope encompassing all major alternative and renewable energy sources, competitive procurement and addresses such areas as distributed generation systems, off-grid solutions, B2B methodologies and rural energy services. It carries forward most of the liberal and attractive incentives of the 2006 Renewable Energy Policy to maintain the investors' confidence and places greater emphasis on the accelerated growth of grid-connected projects as well as a programmatic development of a distributed alternative and renewable energy generation market on more competitive terms. Further, the policy sets the target to increase on-grid renewable energy generation capacity by at least 20 per cent by 2025 and at least 30 per cent by 2030. SHP projects (less than 50 MW) are not covered under this Policy. A separate policy is under consideration for SHP and until then SHP will be developed under the Power Policy 2015

Recently the Government of Pakistan has approved the National Electricity Policy 2021, which has set the goal for sustainable renewable energy market development, with a dedicated gradual increase of the renewable energy share in the generation mix. As for the Indicative Generation Capacity Expansion Plan (IGCEP), the goal is to strengthen the energy security of the country by increasing the projects based on domestic energy and maximizing the renewable energy component. These goals, if seriously implemented, will help make development of SHP projects easier. Eventually, more efforts will be channelled to developing SHP projects in the mountainous regions towards the north of the country, especially in off-grid areas.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The Government of Pakistan as well as selected provincial governments (AJ&K, KP, Punjab and BG) are promoting hydropower development, including SHP, in order to increase the share of hydropower share in the overall energy mix. The provincial Government of Punjab has initiated the approval process of guidelines for development of SHP projects in the captive mode.

To promote private investment in SHP, in September 2017 a facilitation agreement was signed by PPIB and the Government of Azad Jammu and Kashmir. The parties agreed to cooperation and facilitation in setting up private hydropower power projects. Through this arrangement, a tripartite letter of support will be issued to project sponsors and developers and PPIB will facilitate them in establishing private power projects and related infrastructure through signing an implementation agreement and issuing a government guarantee under the provisions of the Power Generation Policy 2015. This initiative is expected to attract and encourage potential investors in developing small to medium-size hydropower projects in the provinces and further augment generation capacities. Earlier, PPIB had already signed a facilitation agreement with the Energy Department of the Government of Khyber Pakhtunkhwa and the Energy Department of the Government of Punjab.

According to NEPRA, comparatively small capital investment and short gestation periods are required to complete these projects. NEPRA has undertaken measures to simplify the investment process for small investors, including the introduction of an upfront tariff. The tariff provides certainty to the potential investors, allows for fast-tracking the development of commercially attractive SHP sites and ensures material risk coverage to the investor. The economic attractiveness of the upfront tariff was further enhanced with the tariff being adjusted for each site depending upon the plant factor.[26] There are three modes of tariffication based upon NEPRA's Competitive Tariff Regulations: cost, tariff and upfront tariff. NEPRA approved a maximum of PKR 13.029 (USD 0.13) per unit for the upfront tariff for SHP projects up to 25 MW under Section 31 (4) of the Regulation of Generation, Transmission and Distribution of Electric Power Act 1997.[27]

COST OF SMALL HYDROPOWER DEVELOPMENT

The average cost of high-head projects is USD 0.8–2 million per MW and for low-head projects the cost is approximately 1.5–USD 4.5 million per MW.[28] Costs in the region of Khyber Pakhtunkhwa are within the range of USD 1.2–2.7 million per MW.[12] The electromechanical equipment is mainly imported, which affects the cost.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The State Bank of Pakistan has initiated a financing scheme for renewable energy projects from 1 MW to 50 MW by providing financing at a 6 per cent interest rate.[29] Initially SHP projects were not included in this scheme, but NEPRA has requested the Government and the State Bank to include SHP in the renewable energy projects list. Further funds from the Clean Development Mechanism (CDM) as well as other funding opportunities associated with efforts to reduce greenhouse gas emissions can be utilized for the development of SHP projects.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The recent changes in the rainfall pattern and intensity can have serious effects on SHP. Cloudbursts can result in flash floods, causing erosion of riverbanks and inflicting serious damage on SHP infrastructure. Many such incidents have been observed in the northern mountainous regions of Pakistan.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The future of SHP development in Pakistan is promising as abundant potential is available in the northern hilly areas, on canal falls and dams in the plains. The Government has devised policies for the development of renewable energy sources including SHP, which is the cheapest source of renewable energy. Nonetheless, a number of factors limiting SHP development in the country persist, including the following:

- Certain federal departments create administrative hurdles to SHP projects. The required consent from these departments, when not provided, block the development of projects;
- The involvement of a large number of institutions and departments and lack of coordination among them, as a result of which projects might take much longer to approve;
- The limited availability of financing and continuity of supply of funds for public sector projects;
- Higher cost of projects due to foreign components;
- Little interest from local manufacturers to develop low-cost electrical and mechanical equipment for SHP plants;
- Risks involved in SHP projects (including hydrology-related ones) can deter developers;
- Gilgit-Baltistan province has a significant large, medium and small hydropower potential; however, its population density and power demand are very low. Moreover, connecting it to the national grid requires very long transmission lines, which makes the development of the available potential unfeasible;
- Limited sustainability of the mini- and micro-hydropower projects developed for off-grid communities in terms of operation and maintenance.

The following points summarize the main enablers for further SHP development in the country:

- Significant potential remaining undeveloped;
- A number of programmes aimed at developing SHP projects in the country;
- The Government of Pakistan as well as selected provincial governments aim to increase the hydropower share in the overall energy mix;
- Need for electricity access, particularly in remote areas of the country.

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Sri Lanka

Danila Podobed, International Center on Small Hydro Power (ICSHP)

KEY FACTS

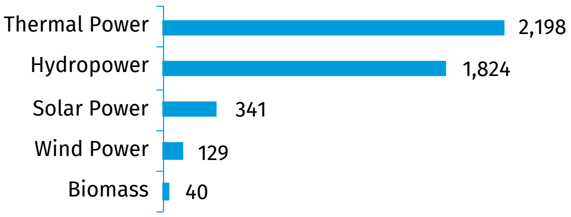
Population	21,919,000 (2020)[1]
Area	65,610 km^2[2]
Topography	The island of Sri Lanka consists of three topographic zones: the plains, the coastal belt and the Central Highlands. The plains compose much of the island's surface, with elevation ranging between 30 and 200 metres above sea level. The coastal belt lies at roughly 30 metres above sea level and consists of sandy beaches punctuated by coastal lagoons. The Central Highlands rise in the south-central part of the country and include high central ridges, plateaus and hills ranging between 400 and 2,000 metres above sea level. The highest point in the country is Pidurutalagala at 2,524 metres.[3]
Climate	The mean annual temperature in Sri Lanka ranges from 26 °C to 28 °C. At Nuwar Eliya at 1,800 metres above sea level the mean temperature is 16 °C. In parts of the Central Highlands, daily extremes range from a high of 37 °C to a low of below 0 °C. The coldest month of the year is January while the hottest month is May.[3]
Climate Change	Between 1961 and 2000, a trend of increase in maximum annual temperatures by up to 0.046 °C has been observed across most observation stations in Sri Lanka. Climate change projections predict a rise in summer monthly temperature of 1.1–2.4 °C by 2100, relative to the 1961–1990 baseline period.[4]
Rain Pattern	Annual rainfall in Sri Lanka is spread over two monsoon seasons and two inter-monsoon seasons. The country receives an average of 1,860 mm of rainfall annually, with variation from 5,500 mm in the central hill region to 950 mm in the coastal plains. Overall, the south-western part of Sri Lanka receives substantially more rainfall than the northern, north-central and eastern regions of the country.[5]
Hydrology	There are 103 rivers in Sri Lanka, with most originating in the Central Highlands and flowing out into the Indian Ocean. The longest river in the country is the Mahaweli River at 330 kilometres, while the Aravi Aru River is the second-longest, at 220 kilometres. There are no natural lakes in Sri Lanka, but many large and small-scale manmade reservoirs have been constructed for electricity generation and irrigation purposes, with some up to 2,000 years old.[6,7]

ELECTRICITY SECTOR OVERVIEW

The total installed electricity capacity of Sri Lanka in 2019 was approximately 4,531 MW, of which thermal power provided 2,198 MW (49 per cent), hydropower provided 1,824 MW (40 per cent), solar power provided 341 MW (8 per cent), wind power provided 129 MW (3 per cent) and biomass provided 40 MW (less than 1 per cent) (Figure 1).[8] By 2020, wind power capacity in the country had expanded substantially to 252 MW, while biomass capacity increased to 54 MW.[9]

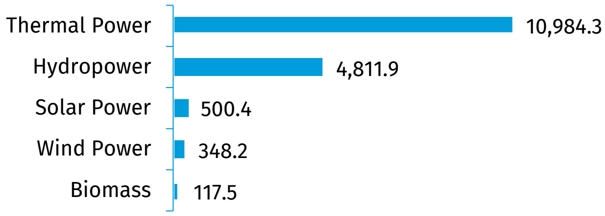
Total electricity generation in 2019 was 16,762.3 GWh, with thermal power accounting for 10,984.3 GWh (nearly 66 per cent), hydropower accounting for 4,811.9 GWh (29 per cent), solar power accounting for 500.4 GWh (3 per cent), wind power accounting for 348.2 GWh (2 per cent) and biomass accounting for 117.5 GWh (less than 1 per cent) (Figure 2). Transmission and distribution losses accounted for 1,372 GWh.[8]

Figure 1. **Installed Electricity Capacity by Source in Sri Lanka in 2019 (MW)**



Source: SEA[8]

Figure 2. **Annual Electricity Generation by Source in Sri Lanka in 2019 (GWh)**



Source: SEA[8]

Access to electricity in Sri Lanka was 100 per cent as of 2020.[10] Electricity consumption in 2019 amounted to 14,769.6 GWh, with the residential sector accounting for 5,523.7 GWh (37 per cent), industrial sector for 4,709.4 GWh (32 per cent), the commercial sector for 4,305.1 GWh (29 per cent) and the remaining 231.4 GWh (2 per cent) being accounted for by agriculture, street lighting and religious institutions. Transmission and distribution losses accounted for 1,372.0 GWh, while own use by producers accounted for 649.1 GWh.[8]

The state-owned company Ceylon Electricity Board (CEB) is the largest electricity producer in the country which owns the largest share of generating capacity as well as the transmission, distribution and retail sales of electricity. The Lanka Electricity Company (LECO) is a smaller company engaged in the distribution of electricity purchased from CEB to end users.[11,12]

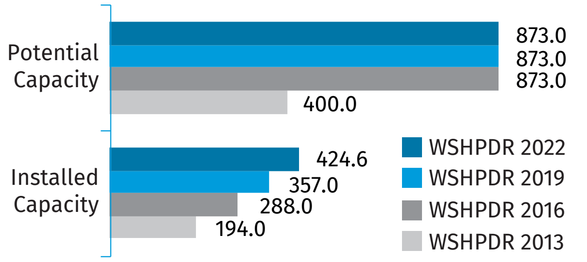
Electricity tariffs in Sri Lanka are set by the Public Utilities Commission of Sri Lanka (PUCSL), the economic, technical and safety regulator of the electricity sector in the country.[13] End user electricity tariffs have not changed since 2014, and range from 2.5 LKR/kWh to 45.0 LKR/kWh (0.007–0.130 USD/kWh) for residential users, based on monthly consumption volumes, and from 1.9 LKR/kWh to 26.6 LKR/kWh (0.005–0.074 USD/kWh) for non-residential users, with certain users charged by consumption volume and others based on peak, daytime and off-peak time of use (ToU) intervals. ToU tariffs are also optionally available for residential customers and range from 13.0 LKR/kWh to 54.0 LKR/kWh (0.036–0.150 USD/kWh).[14]

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) is defined in Sri Lanka as hydropower plants with an installed capacity of up to 10 MW and is additionally classified as a new renewable energy (NRE) resource, a category which excludes large hydropower and includes power plants running on other renewable energy sources.[15,16]

There were 205 grid-connected SHP plants in Sri Lanka at the end of 2019, with a total installed capacity of 424.6 MW and which generated a total of 1,011.0 GWh the same year.[8] SHP potential in the country has been estimated at 873 MW, indicating that approximately 49 per cent has been developed.[15,17] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed SHP capacity in Sri Lanka has increased by almost 19 per cent due to the construction of additional plants, while potential capacity has remained the same, as no comprehensive updated estimate of SHP potential has been produced (Figure 3).[15]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Sri Lanka (MW)**



Source: SEA,[8] *WSHPDR 2019*,[15] *WSHPDR 2013*,[18] *WSHPDR 2016*[19]

The development of SHP in Sri Lanka has a long history, with the first SHP plant commissioned in 1996.[17] SHP development has been concentrated in the central parts of the country, with the Ratnapura and Nuwara Eliya districts leading the country in installed SHP capacity. Sri Lanka has developed considerable expertise in SHP, which it has sought to market internationally, with SHP developers from Sri Lanka involved in SHP projects in other parts of Asia as well as in African countries.[20] Domestic development of SHP in Sri Lanka is actively ongoing, with 11 new SHP plants commissioned in 2019.[8] However, bottlenecks in the procurement process have led to delays in the construction of a large number of projects with a cumulative capacity of 100 MW and no new standardized power purchase agreements (SPPAs) for SHP have been approved by the Government since 2015.[17,21] A list of recently commissioned SHP plants is available in Table 1.

Table 1. **List of Selected Existing Small Hydropower Plants in Sri Lanka**

Name	*Capacity (MW)*	*Operator*	*Launch year*
Koswathu Ganga	3.00	Finconsult Hydro Power Ltd	2019
Elgin	2.40	Elgin Hydropower Ltd	2019
Upper Hulu Ganga	1.90	Upper Hulu Ganga Ltd	2019
Marukanda	1.80	Kuruganga Hydro Ltd	2019
Loggal Oya	1.35	Loggal Oya Hydro Power Ltd	2019
Loinorn	1.00	Loinorn Hydro Ltd	2019
Denipalle Oya	0.75	Energy Craft Ltd	2019
Deegalahinna Cascade II	0.55	Deegalahinna Mini Hydro Power Ltd	2019
Moragahakanda Phase I	10.00	Ministry of Mahaweli & Development & Environment	2018
Moragahakanda Phase II	7.50	Ministry of Mahaweli & Development & Environment	2018
Moragahakanda Phase III	7.50	Ministry of Mahaweli & Development & Environment	2018
Bambarapana	2.50	Bambarapana Hydropower Ltd	2018
Manakola	2.50	H Hydro WV Ltd	2018
Udawela	1.40	Udawela Hydro Ltd	2018

Name	Capacity (MW)	Operator	Launch year
Ankanda	1.20	Escas Ankanda Ltd	2018
Polgaswaththa	1.00	S&N Power Mini Hydro Power Project Ltd	2018
Thannewatha	1.00	Thannewatha Mini Hydro Power Holding Ltd	2018
Maliyadda	0.90	Biomed Hydro Power Ltd	2018
Mossville Estate	0.90	Mossville Hydro Power Ltd	2018
Ranwala Oya	0.70	J B Power Company Ltd	2018

Source: SEA[8,22]

RENEWABLE ENERGY POLICY

The key element driving the renewable energy policy of Sri Lanka is the cost of fossil fuel imports for power generation in the country, which exceeded USD 100 million per month in 2022.[23] Policy decisions on renewable energy are guided by the Sri Lanka Sustainable Energy Authority (SEA), established by the Sustainable Energy Authority Act No. 35 of 2007.[24] The SEA acts as the regulator of renewable resource use and land allocation for renewable energy projects.[15]

As part of its Energy Sector Development Plan for a Knowledge-Based Economy 2015–2025, the Government of Sri Lanka had set a target of a 100 per cent share of electricity generation from renewable energy sources by 2030.[25] However, this target has been subsequently revised to 70 per cent, while aiming to achieve carbon neutrality by 2050.[26]

These targets are to be fulfilled in part through the expansion of solar power capacity to a total of 2,000 MW by the end of 2023.[26] The Renewable Energy Resource Development Plan 2021–2026 outlines the focus of future renewable energy development on prioritizing large- and medium-scale renewable energy parks with cumulative capacities in the range of 100 MW, without neglecting the development of smaller-scale capacities. For hydropower, the Plan identifies an undeveloped potential capacity of 1,082 MW for run-of-river hydropower plants, without specifying an upper installed capacity threshold.[27]

In 2010, Sri Lanka launched a programme of incentivizing renewable energy development through feed-in tariffs (FITs), at the time some of the highest in the Global South.[28] The country subsequently transitioned to a bidding system for renewable energy tenders, which lowered power purchase prices for electricity from renewable energy sources to an average of 18 LKR/kWh (0.050 USD/kWh), from the 22–25 LKR/kWh (0.061–0.069 USD/kWh) under the FIT system.[29] However, in June 2022 the Government acted to remove the competitive bidding system for renewable energy projects, justifying the change by a need for rapid addition of new renewable energy capacity to the grid.[30]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Barrier to SHP development in Sri Lanka include the following:

- Legal and administrative bottlenecks preventing the signing of new SPPAs with SHP developers;
- Lack of an up-to-date estimate of the remaining undeveloped SHP potential;
- Issues at the grid and subgrid level interfering with power connections to, and transmission of, power from new SHP plants;
- Lack of community involvement in SHP development and unequal sharing of value generated by SHP plants among local communities;
- Absence of effective monitoring of SHP plant development and operation to ensure environmental compliance;
- Public opposition to further SHP development.[15]

Enablers to SHP development in Sri Lanka include:

- Considerable local technical expertise in domestic and international SHP development;
- Abundant remaining potential SHP capacity in some parts of the country;
- Demand for renewable energy development due to the high cost of fossil fuel imports;
- Government policy strongly supportive of renewable energy development.

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3.4. South-Eastern Asia

Countries: Cambodia, Indonesia, Lao People's Democratic Republic, Malaysia, Myanmar, Philippines, Thailand, Timor-Leste, Viet Nam

INTRODUCTION TO THE REGION

The region of South-Eastern Asia is undergoing rapid development and countries in the region have adopted different strategies with regard to the structure and developmental trajectory of their electricity sectors. The largest electricity producers in the region are Viet Nam and Indonesia. The electricity sector of Indonesia relies on a variety of energy sources and leads the region in installed geothermal power capacity, but is still dominated by fossil fuels. Viet Nam has a highly diversified energy mix and invests heavily in renewable energy sources, in part by attracting foreign renewable energy developers. Thailand is also focused on the development of renewable energy and leads the region in biomass capacity, which is also the country's leading energy source by installed capacity. Myanmar and Cambodia both employ a mix of hydropower and thermal power for generation, with Cambodia additionally having a significant solar power capacity. The electricity sectors of the Philippines and Malaysia are dominated by thermal power from fossil fuel-fired power plants, although both countries are making strides in the development of hydropower and other renewable energy technologies, including biomass, solar power and geothermal power. Timor-Leste is almost entirely dependent on diesel-fired thermal power plants, although solar power is beginning to make inroads in the country.

Hydropower is the leading energy source by installed capacity in Cambodia and the Lao People's Democratic Republic (Lao PDR) and a primary energy source for Viet Nam, Myanmar and Thailand. In practice, however, hydropower generation often lags behind that of thermal power by a significant margin, particularly in Thailand, with only the Lao PDR relying primarily on hydropower for electricity generation. In the Lao PDR, hydropower plays a unique role, as the country's generation capacity far exceeds current domestic demand. The Lao PDR is aiming to position itself as the leading electricity exporter in mainland South-Eastern Asia, with its electricity exports accounting for approximately two thirds of domestic electricity generation on average and reaching nearly 79 per cent in 2020. Much of this export-oriented generation in the Lao PDR is produced by hydropower plants of various sizes operated by independent power producers (IPPs), including foreign companies eager to invest in the country to take advantage of its abundant hydropower resources.

In other countries in South-Eastern Asia, hydropower plays an important but supplementary role. Viet Nam is the region's leading hydropower producer, but currently existing capacities are at near saturation relative to the remaining large-scale hydropower potential and further substantial expansion of the sector is unlikely. In contrast to other regional countries, the hydropower sector is almost non-existent in Timor-Leste and all existing hydropower plants in the country are operating at below capacity or are fully out of operation.

An overview of the electricity sectors of the countries in the region is provided in Table 1.

Table 1. **Overview of South-Eastern Asia**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Cambodia	16	81	97	2,916	8,513	1,330	3,493
Indonesia	271	99	99	69,679	278,502	5,976	N/A
Lao PDR	7	100	100	10,328	39,967	8,304	N/A
Malaysia	33	100	100	26,030	168,906	6,245	26,296
Myanmar	54	56	N/A	6,977	23,532	3,262	10,107
Philippines	110	93	94	25,531	106,040	3,760	8,025
Thailand	70	100	100	39,760	186,503	3,110	6,310
Timor-Leste	1	96	94	305	604	0.4	2
Viet Nam	97	100	100	68,725	235,410	20,774	73,382
Total	-	-	-	**250,251**	-	**52,761**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in South-Eastern Asia differs across countries. In Cambodia, Indonesia, Myanmar and the Philippines, SHP refers to hydropower plants with an installed capacity of up to 10 MW, while in the Lao PDR the threshold is 15 MW and in Malaysia and Viet Nam it is 30 MW. In Timor-Leste, the up to 50 MW definition is used. Thailand adheres to the up to 6 MW definition of SHP.

A comparison of installed and potential SHP capacities in the South-Eastern Asia region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in South-Eastern Asia (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Cambodia	Up to 10 MW	1.7	300.0	1.7	300.0
Indonesia	Up to 10 MW	543.0	19,385.0	543.0	19,385.0
Lao PDR	Up to 15 MW	162.0	2,287.0	N/A	N/A
Malaysia	Up to 30 MW	296.0	1,500.0	N/A	N/A
Myanmar	Up to 10 MW	42.9	114.0	42.9	114.0
Philippines	Up to 10 MW	145.0	1,265.0	145.0	1,265.0
Thailand	Up to 6 MW	190.4	700.0	190.4*	700.0*
Timor-Leste	Up to 50 MW	0.4	N/A	0.4	219.8
Viet Nam	Up to 30 MW	3,600.0	7,200.0	N/A	N/A
Total	-	-	-	**923.4**	**21,983.8**

Source: *WSHPDR 2022*,[1] *WSHPDR 2019*[2]

Note: *Based on the local definition of SHP.

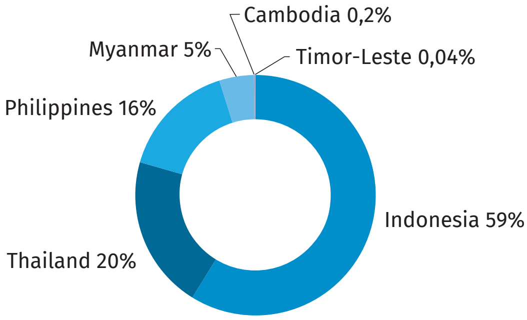
The total installed capacity of SHP up to 10 MW in South-Eastern Asia is 923.4 MW, while potential capacity is estimated at

21,983.8 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has increased by approximately 9 per cent, while the estimated potential capacity increased by 34 per cent. The regional increase in capacities is primarily due to the expansion of installed capacity and a re-evaluation of potential capacity for SHP up to 10 MW in Indonesia. The largest expansion of installed SHP capacity in recent years has taken place in Viet Nam, but a direct comparison is complicated due to differing definitions of SHP.

SHP plays a major role in the energy strategy of many countries in South-Eastern Asia, variously forming a significant part of the domestic electricity supply to the national grid, attracting foreign investment, generating electricity for export and providing a means of rural electrification in remote areas. Viet Nam has the largest SHP sector in the region and one that is undergoing rapid development, having more than doubled its installed capacity in recent years. Active development of SHP is also taking place in Indonesia, Malaysia and Thailand, as well as in the Lao PDR, where the Government has had to adopt measures to reign in poorly-managed expansion of SHP projects. Myanmar has marginally increased its installed SHP capacity over the last few years but development is hampered by a number of factors including the ongoing conflict in the country. A number of new SHP plants have been built in recent years in the Philippines. By contrast, the SHP sector in Cambodia has stagnated as the country has focused on the development of large hydropower and other forms of renewable energy. Likewise, the few existing SHP plants in Timor-Leste have fallen into disrepair and no new projects are under consideration.

The national share of regional installed capacity for SHP up to 10 MW by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

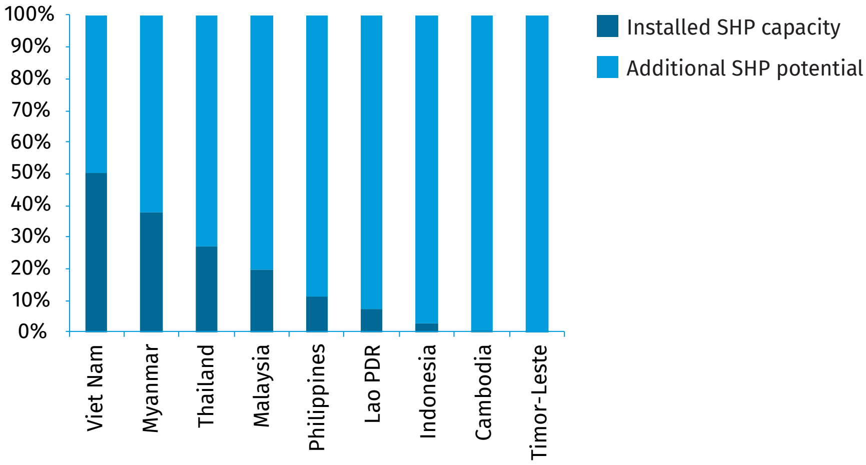
Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in South-Eastern Asia (%)**



Source: *WSHPDR 2022*[1]

Note: The Lao PDR, Malaysia and Viet Nam are not included due to lack of data.

Figure 2. **Utilized Small Hydropower Potential by Country in South-Eastern Asia (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP up to 10 MW in the case of Myanmar, Philippines, Indonesia, Cambodia and Timor-Leste; data for the local definition of SHP used in the case of Viet Nam, Thailand, Malaysia and the Lao PDR.

As of 2020, the installed SHP capacity of **Cambodia** consisted of four plants with a total installed capacity of 1.7 MW constructed under grant aid from the Government of Japan and managed by the country's public electricity company. Several additional private micro-hydropower plants exist in different parts of the country, but data on their installed capacity is lacking. The country's potential capacity for SHP up to 10 MW is estimated at 300 MW, indicating that less than 1 per cent has been developed. There were nine SHP projects in the country in advanced stages of study as of 2021, in addition to 39 identified potential sites.

Indonesia has the region's second-largest SHP capacity at 543 MW (for SHP up to 10 MW) and the largest SHP potential, estimated at 19,385 MW, indicating that approximately 3 per cent has been developed. The country is actively pursuing SHP development, adding over 200 MW of additional SHP capacity in 2019–2020. New SHP plants have included both larger plants in the 1–10 MW capacity range as well as mini-hydropower plants with capacities below 1 MW, and have been constructed for both on-grid and off-grid operations. Multiple feasibility studies have been published in recent years, with the latest estimate of the country's SHP capacity dating to 2019.

The installed capacity of SHP up to 15 MW in the **Lao PDR** was 162 MW as of 2019, while potential capacity is estimated at 2,287 MW, indicating that 7 per cent has been developed. The country saw a burst of activity in the SHP sector following deregulatory reforms adopted in 2011, which delegated the approval process for SHP plants to provincial authorities, while also limiting investment in the SHP sector to local entities. Subsequent reforms adopted in 2017, following a string of disasters in the hydropower sector, again tightened central Government oversight of all hydropower projects but opened the SHP sector to foreign investment. As of 2019, there was a total of 252 MW of SHP projects in the development pipeline.

In **Malaysia**, the total installed capacity of SHP up to 30 MW was 296 MW in 2019 and potential capacity is estimated at 1,500 MW, indicating that 20 per cent has been developed. SHP development in the country has been very active, with over a dozen SHP plants build in 2017–2020 with capacities ranging from 2.2 MW to 24.5 MW. The construction of SHP projects has been spurred by the adoption of feed-in tariffs (FITs) in 2011. At the end of 2020, a total of 530 MW of SHP projects were in various stages of implementation.

The verifiable installed capacity of SHP up to 10 MW in **Myanmar** was 42.9 MW as of 2021, provided by nearly 350 SHP plants operated by the Ministry of Electricity and Energy as well as other government ministries. Additionally, over 2,000 privately-run micro-hydropower plants are estimated to exist across the country, but data on their cumulative capacity is not available. The potential capacity of SHP up to 10 MW in the country is estimated at 114 MW based on existing plants and identified sites, indicating that nearly 38 per cent has been developed. Two new SHP plants were constructed in Myanmar in 2018 and several projects were in the early planning stages as of 2021.

The installed capacity of SHP up to 10 MW in **the Philippines** was 145 MW as of 2021, while potential capacity is estimated at 1,265 MW, indicating that over 11 per cent has been developed. While the SHP sector in the country has seen active development in recent years, the total installed capacity of the country has decreased by a small margin due to the exclusion of non-operational SHP plants from government databases. A total of 17 new hydropower projects, primarily within the category of SHP, were in the early planning stages as of 2021.

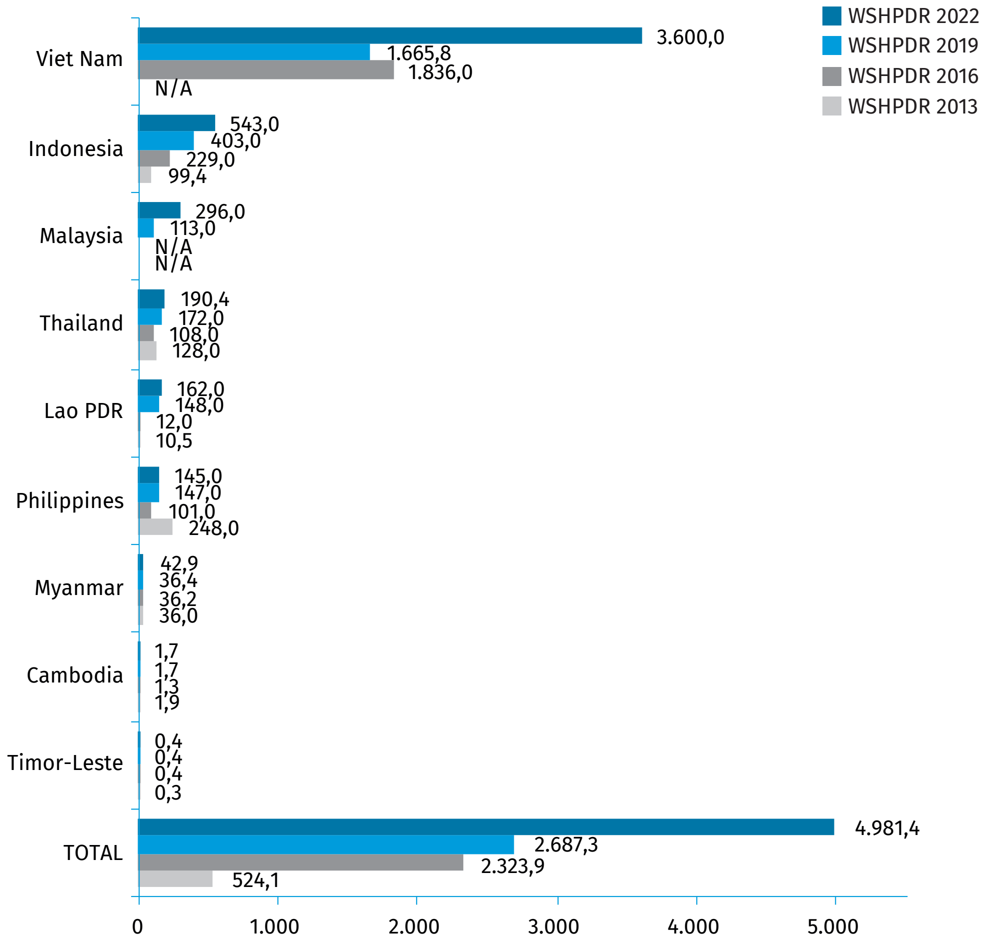
In **Thailand**, the installed capacity of SHP up to 6 MW was 190.4 MW as of 2020. The potential capacity for SHP up to 6 MW in the country is estimated at 700 MW, mostly concentrated in the northern part of the country, indicating that approximately 27 per cent has been developed. Several new plants have been constructed in recent years. The development of SHP in the country is promoted by the national Alternative Energy Development Plan (AEDP2018), which has set a goal of increasing the total installed capacity of SHP in the country to 376 MW by 2037. A total of 256 potential sites have been identified in the northern part of Thailand.

Timor-Leste has 0.4 MW of SHP capacity provided by three plants, which are all either fully inoperable or operating at significantly reduced capacity. The potential for SHP up to 10 MW in the country is estimated to be at least 219.8 MW, suggesting than 1 per cent has been developed. Potential SHP sites in the country have been inventoried by several detailed studies, but no concrete plans for further development of the SHP sector exist.

The total installed capacity of SHP up to 30 MW in **Viet Nam** was approximately 3,600 MW as of 2020, while potential capacity is estimated at 7,200 MW, indicating that 50 per cent has been developed. The SHP sector of Viet Nam has been growing at a rapid pace, more than doubling in installed capacity since the publication of the *WSHPDR 2019*. While the country's rapidly growing economy has led to ever-increasing electricity demand, its commitment to decarbonizing the electricity sector has led the Government to reduce targets for the expansion of thermal power while pursuing a radical expansion of hydropower, wind power and solar power over the next decade. With much of the country's potential large hydropower capacity nearing saturation, the development of SHP is expected to play an ever-increasing role in the overall growth of the hydropower sector. Under the draft Power Development Plan published in 2022, Viet Nam is aiming to increase its total SHP capacity to 5,000 MW by 2030 and to 5,900 MW by 2045. At the same time, accidents and environmental concerns have caused the Government to increase scrutiny of the SHP sector, leading to the cancellation of hundreds of planned and ongoing projects over the last decade.

Changes in the installed SHP capacities of countries in the region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in South-Eastern Asia (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2019*,[2] *WSHPDR 2013*,[3] *WSHPDR 2016*[4]

Note: For SHP up to 10 MW in the case of Myanmar, Philippines, Indonesia, Cambodia and Timor-Leste; data for the local definition of SHP used in the case of Viet Nam, Malaysia, Thailand and the Lao PDR.

Climate Change and Small Hydropower

The hydrological regime in the region is governed by monsoon precipitation that is influenced by the El Niño Southern Oscillation (ENSO) and many regional countries such as the Philippines are highly vulnerable to climate change impacts. Climate change models predict future increases in flood damage and water supply deficits across the region. Countries such as the Lao PDR are already experiencing the impact of climate change, with hydropower generation shortfalls of 13–22 per cent registered in 2020. Hydropower development policies in the region should prioritize dam safety and basin planning to mitigate risks to SHP associated with flash flooding events. Moreover, reservoir-based SHP plants should be considered for future water infrastructure development to avoid the elevated vulnerability of run-of-river plants to fluctuations in streamflow.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Cambodia has considerable untapped SHP potential, but the country's renewable energy strategy has prioritized the development of large hydropower and other renewable energy sources over SHP, with solar power taking the lead in providing electricity access to remote off-grid locations in rural areas. A lack of a policy and legal frameworks and high construction costs make SHP less competitive than solar power projects that can be implemented on an ad-hoc basis. Despite several studies identifying a number of SHP sites in various parts of the country, comprehensive scientific data on prospective sites are also lacking.

The prospects for SHP development in **Indonesia** are overall very promising, as the country has targeted the development of both large hydropower and SHP as a climate change adaptation measure and, in the latter case, a means of off-grid electrification of remote areas. Government policy provides support for SHP development both in the form of FITs and power purchase guarantees. It is hoped that the SHP sector can become a platform for foreign direct investment, although currently funding is largely provided by the Government and domestic private investors. Issues complicating the development of SHP in the country include vague and complicated regulatory frameworks and licensing procedures, while regulations on foreign investment in the country are still perceived as inflexible and discouraging of large-scale investment in SHP.

The **Lao PDR** is likewise a promising market for SHP development due to the country's established role as a regional exporter of electricity from hydropower and strong momentum in the SHP sector since 2011, despite a number of high-profile dam failures and increased regulation. The Government's commitment to improving the quality of hydropower operations in the country through transparent negotiation procedures, regulatory frameworks and elevated operational standards stands to contribute to greater investment in the SHP sector. Remaining outstanding issues include the absence of a financing scheme specifically targeting SHP, frequently changing legislative frameworks and low domestic demand for electricity.

In **Malaysia**, support for SHP development has been historically provided by FITs allocated to independent power producers by the national electricity utility under the renewable energy power purchase agreements (REPPA). For most SHP plants, purchase tariffs for electricity are now determined through a competitive e-bidding system rather than predetermined premiums. Support is also provided in the form of power purchase guarantees and priority of dispatch, significantly reducing demand risk, as well as by flexible operating requirements with regard to generation volume. Barriers to SHP development include seasonal and topographic constraints on construction, long licensing periods and lack of adequate inter-grid connectivity, which complicates the evacuation of power.

Development of SHP in **Myanmar** is hindered by the lack of a comprehensive regulatory framework providing support for SHP, limited financial resources as well as limited ability of the local population to pay for electricity, limited local technical capacity and overall economic and political instability in the country. Assuming external financing can be attracted, the most promising direction for SHP development in Myanmar lies in off-grid applications in rural areas in need of electrification.

In the **Philippines**, SHP is incentivized through the Mini-Hydro Law, which provides privileged tax rates for SHP investments as well as tax and customs waivers for imports of materials and equipment for SHP projects. Additional support options for SHP include FITs and net metering as well as several international programmes providing funds for SHP development alongside other renewable energy sources. The country has a large, mostly untapped potential for further SHP construction. At the same time, development of SHP is hindered by increasing public opposition to hydropower, particularly due to competition for water resources from the agricultural sector, as well as a lack of domestic financing opportunities, particularly from the private sector.

Thailand has actively pursued renewable energy development and provides incentives for SHP in the form of FITs. While the country has considerable untapped SHP potential in the northern part of the country, most of the identified sites in this region lie in protected areas and are likely unsuitable for development. Additionally, the legal framework regulating the ownership of SHP projects is currently seen as unattractive by potential investors.

There is a potentially significant untapped SHP capacity remaining in **Timor-Leste**. However, development of SHP in the country is complicated by an over-supply of electricity leading to low demand for additional capacities in the near future, as well as by unique geological conditions which make the impoundment of water in reservoirs particularly difficult. The high cost of power generation from imported fossil fuels, electricity demand in off-grid rural settlements and the need for rehabilitation of existing capacities may provide some future opportunities for investment in SHP projects in the country.

There are many favourable factors for SHP development in **Viet Nam**, including significant undeveloped SHP capacity, comprehensive data sets on potential SHP sites and concrete plans for the expansion of the SHP sector over the next decade. While no FITs for SHP are available, development in the sector is incentivized through avoided-cost tariffs, defined as the difference between the cost of generation from SHP and the cost of generation of an equivalent amount of electricity from thermal power. Barriers to SHP development in the country include an insufficiently robust institutional and regulatory framework leading to lax oversight and environmental risks, poor quality control and ongoing revisions to national development plans leading to uncertainty among potential investors.

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Cambodia

Naichy Sea, Panha Hok, Chhunleang Rorm and Piseth Chea, Electricité Du Cambodge (EDC)

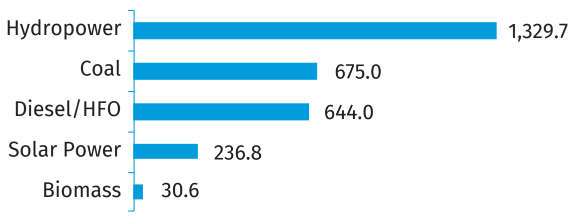
KEY FACTS

Population	16,486,542 (2019)[1]
Area	181,035 km[2]
Topography	Cambodia is characterized by four distinct topographical regions. The north is formed by an escarpment of the sandstone Dangrek Mountains. The south-west is dominated by the granite Cardamom Mountains, with the highest peak being the range of Phnom Aural. It reaches 1,813 metres above sea level and forms a watershed boundary between the rivers flowing down into Tonle Sap Lake and those flowing to the coastal area. The central flat lowland of Tonle Sap Lake is bounded by isolated hills. The east is dominated by mountain ranges.[2]
Climate	Cambodia has a tropical monsoon climate with two distinct seasons: six months of the dry season from November to April followed by six months of the rainy season from May to October Temperatures are the hottest in April with a monthly average of 29 °C (maximum 36 °C) and coolest in December and January (25.7 °C).[2]
Climate Change	The International Panel on Climate Change reported that Cambodia has already been experiencing long-term changes in climate and is plausibly vulnerable and exposed to this impact due to its low adaptive capacity and resilience.[3] In the future, the temperature in Cambodia is expected to get warmer, while changes in rainfall indicate an unclear trend and variability depending on the climate models used, geographical location and timeframe.[4] Changing rainfall patterns with warmer temperatures will lead to increased flooding, drought and storms which will also reduce resource productivity, especially in agriculture and fishery, and increase damage from extreme events, affecting electricity generation, roads, water supply and other infrastructure.[5]
Rain Pattern	The rainfall pattern of Cambodia is bimodal with two rainy seasons: in June/July and September/October. Average annual precipitation is 1,400 mm, but varies from 1,000 mm in the west to 4,700 mm in the south.[2]
Hydrology	The territory of Cambodia consists of three major watersheds: the Tonle Sap Lake/River, the Mekong River and the coastal area. Those represent 44, 42 and 14 per cent of the country's land area, respectively. The Cambodian section of the Mekong River has a length of 486 km with the drainage area of approximately 155,000 km^2. Phnom Penh is located at the confluence of the Mekong and Tonle Sap Rivers and marks the beginning of the Cambodian Mekong floodplain. Downstream of Phnom Penh, the Mekong River splits into two: the mainstream Mekong River and the Bassac River tributary.[2]

ELECTRICITY SECTOR OVERVIEW

As of December 2020, the total installed capacity in operation in Cambodia was 2,916 MW. Hydropower, coal and diesel/heavy fuel oil (HFO) contributed 46, 23 and 22 per cent, respectively. Solar power and biomass accounted for the remaining 8 and 1 per cent of total capacity, respectively (Figure 1).[6]

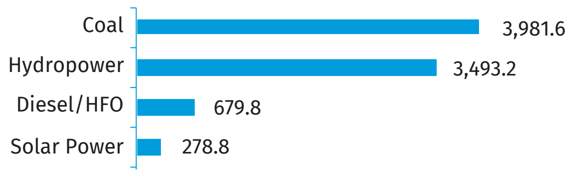
Figure 1. **Installed Electricity Capacity by Source in Cambodia in 2020 (MW)**



Source: EAC[6]

In 2020, total domestic generation amounted to 8,513 GWh with approximately 47 per cent supplied by coal, 41 per cent by hydropower, 8 per cent by diesel/HFO and approximately 4 per cent by solar power and biomass combined (Figure 2).[6]

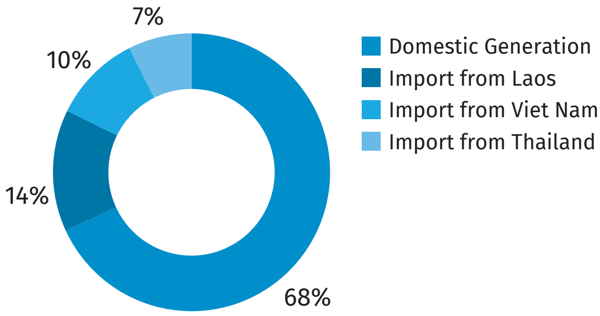
Figure 2. **Annual Electricity Generation by Source in Cambodia in 2020 (GWh)**



Source: EAC[6]

In order to meet the demand, in 2020 Cambodia imported approximately 3,986 GWh (32 per cent of total consumption) from the neighbouring countries, including Thailand, Viet Nam and Laos (Figure 3).[6]

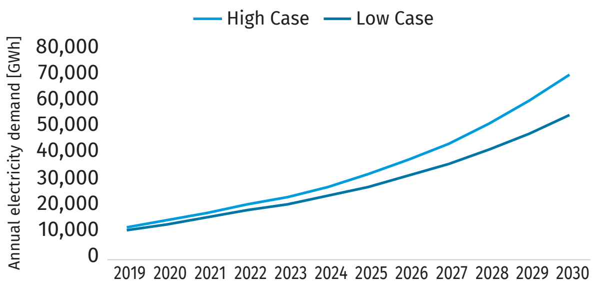
Figure 3. **Domestic and Imported Electricity in Cambodia in 2020 (%)**



Source: EAC[6]

The country's electricity demand has been growing fast. Between 2009 and 2019 the average annual growth rate of electricity supply was 19 per cent, whereas energy demand increased by approximately 18 per cent per year. Conservative forecasts (low case) estimate that the demand will rise from 13,494 GWh in 2020 to 27,766 GWh by 2025 and 54,804 GWh by 2030 (approximately a 400 per cent increase) (Figure 4).[7]

Figure 4. **Electricity Demand Forecasts in Cambodia 2015–2030 (GWh)**



Source: Chugoku Electric Power[7]

To meet the increasing demand, the Government of Cambodia has developed the Power Development Plan (PDP) for 2008–2021 and currently the new PDP and Electricity Supply Development Plan for 2020–2040 are under study. In line with the PDP, transmission lines are under construction and electricity has been imported from neighbouring countries. In 2011, the Government formulated the Promotion and Strategy Plan for Rural Electrification and set the target of at least 70 per cent of households to have access to quality grid-supplied electricity by 2030. As a result, by the end of 2020, the total household electrification rate reached 81 per cent, exceeding the Government's target.[6] By the end of 2020, 13,798 villages representing over 97 per cent of the total were electrified, while 370 villages representing less than 3 per cent were non-electrified.[6]

The Government also formulated the Electricity Supply Development Plan by 2020 aiming to increase the electricity generation from hydropower, coal and solar power in order to reduce generation from diesel and HFO as well as the country's dependency on imported fuels. As per the plan, seven new hydropower plants and three coal power plants were finalized and are currently operating. This allowed bringing the maximum capacity, including imported electricity, up to 3,897 MW in 2020.[6] The observed increase in installed capacity reflects the dramatic growth in demand, which resulted mainly from the stable political situation allowing the economic activity in all sectors to rapidly increase in the last decade. Moreover, the extension of the transmission network and the decrease in electricity prices for specific sectors are also factors that have contributed to the electricity consumption growth in the last few years.

At the end of 2020, the transmission network reached a total length of 3,130 kilometres combined of 500 kV, 230 kV and 115 kV transmission lines and 43 substations supplying directly to 24 cities and provinces. A further 2,133 kilometres of transmission lines and 15 new substations, capable of supplying directly to 25 cities and provinces, were planned or under construction.[6]

The power sector in Cambodia is administered and managed under the Electricity Law. Ratified in 2001, the law provides a policy framework for the development of an unbundled sector, facilitating substantial private sector participation on a competitive basis in generation and distribution. The Electricity Law also defines the roles of the Ministry of Mines and Energy (MME) as the policy maker, the Electricity Authority of Cambodia (EAC) as the regulator and supervisor and the Rural Electricity Enterprises (REEs) as the electricity service providers. MME is responsible for the planning and development of power projects through granting study rights and concessions for power generation to the REEs and Independent Power Producers (IPPs), development of related policies and strategies, promotion of the use of domestic energy resources, planning of electricity export and import as well as subsidies to specific classes of customers. In its turn, EAC is responsible for the control and regulation of the electricity sector, licences for the provision of electricity power services and tariffs.[8,9]

Electricité du Cambodge (EDC) is a state-owned limited liability company under the control of MME and the Ministry of Economy and Finance (MEF) and was authorized by a Royal Decree in 1996. In 2002, EDC acquired the consolidated licence from EAC and is responsible for electricity generation, transmission and distribution as well as electricity imports from, and exports to, the neighbouring countries. EDC is the largest of the REEs in the country. Other private REEs, such as Community Electricity Cambodia (CEC), are allowed to provide electricity to the national grid.

Due to the large hydropower potential being harnessed and additional coal power plants being developed, electricity tariffs are expected to decline in the future (Table 1). However, with the ongoing national power grid upgrade works, the tariffs will also have to compensate for the related costs.

Besides the regular electricity tariff rates, the Government also provides tariff reductions and subsidies.

Table 1. Residential Tariff Rates in Cambodia in 2016–2021

Type of consumption	*Tariff (USD/kWh)*					
	2016	*2017*	*2018*	*2019*	*2020*	*2021*
Electricity supplied by EDC in Phnom Penh and Takmao city						
>200 kWh/month, other than residents	0.195	0.193	0.188	0.185	0.183	0.183
51–200 kWh/month	0.180	0.180	0.180	0.153	0.153	0.153
11–50 kWh/month	0.153	0.153	0.153	0.120	0.120	0.120
< 10 kWh/month	0.120	0.120	0.120	0.095	0.095	0.095
Electricity supplied by EDC outside Phnom Penh and Takmao city						
>200 kWh/month, other than residents in provincial towns	0.195	0.193	0.188	0.185	0.183	0.183
>200 kWh/month), other than residents in rural areas	0.200	0.198	0.193	0.185	0.183	0.183
51–200 kWh/month in provincial towns	0.195	0.193	0.188	0.183	0.183	0.183
51–200 kWh/month in rural areas	0.200	0.198	0.193	0.183	0.183	0.183
11–50 kWh/month in provincial towns and rural area	0.200	0.183	0.183	0.120	0.120	0.120
< 10 kWh/month in provincial towns and rural area	0.120	0.120	0.120	0.095	0.095	0.095

Source: EAC[6]

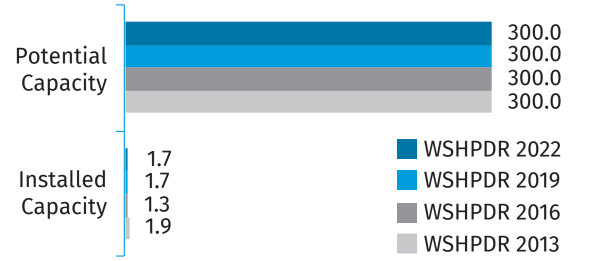
SMALL HYDROPOWER SECTOR OVERVIEW

Hydropower plants with an installed capacity of up to 10 MW are defined as small.

The current installed small hydropower (SHP) capacity is approximately 1.655 MW with an additional undeveloped potential of approximately 300 MW, indicating that 0.55 per cent of the potential has been harnessed.[10] In comparison to the *World Small Hydropower Development Report (WSHPDR) 2019*, both the installed and potential capacity have remained unchanged (Figure 5).

As of 2020, the installed SHP capacity of Cambodia consisted of four plants constructed under grant aid from the Government of Japan, and managed and operated by EDC (Table 2). There are also several privately-owned micro- and pico-hydropower plants in the northern part of the country, technically supported from Viet Nam and China, with individual installed capacities ranging between 1 kW and 30 kW. However, data on their installed capacity are not included in the total reported in this chapter.

Figure 5. Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Cambodia (MW)



Source: MME,[10] *WSHPDR 2013*,[11] *WSHPDR 2016*,[12] *WSHPDR 2019*[13]

Table 2. List of Operational Small Hydropower Plants in Cambodia

Name	*Location*	*Installed capacity (MW)*
O'Chum 1	Rattanakiri	0.265
O'Chum 2	Rattanakiri	0.960
O'Mleng	Mondulkiri	0.215
O'Romis	Mondulkiri	0.215
Total		**1.655**

Source: MME[14]

There are additional nine projects in an advanced study stage with a combined potential capacity estimated at almost 19 MW (Table 3).[14] A further 39 sites with a potential of 30 MW have also been identified and are in the reconnaissance stage (Table 4).[14] In 2006, the Ministry for Industry, Mines and Energy (now MME) and the Cambodian National Mekong Committee (CNMC) reviewed the country's hydropower potential and identified 63 potential sites for SHP and large hydropower projects throughout the country.[15] The total hydropower potential of Cambodia is estimated at approximately 10,000 MW, of which 1,321 MW was developed as of 2020.[16] Thus, only a small fraction of the country's total hydropower installed and potential capacity is from SHP. However, many large hydropower sites identified are highly controversial and unlikely to be developed due to such factors as negative impact on fishery, resettlements, land issues, limited environmental and social impact assessments as well as community consultations.

Table 3. List of Small Hydropower Sites in Advanced Study Stage in Cambodia in 2021

Name	*Location*	*Capacity (MW)*
Prek Por	Mondulkiri	4.80
Stung Kep	Kep City	4.10
O Phlai	Mondulkiri	3.40
O Sla Up Stream	Koh Kong	1.90
Stung Siem Reap 3	Siem Reap	1.70

Name	*Location*	*Capacity (MW)*
O Turou Trao	Kampot	1.12
O Kachanh	Ratanakiri	0.10
Stung Chikreng	Siem Reap	0.80
Prek Teuk Chhu	Kampot	0.76
Total		**18.68**

Source: MME[14]

Table 4. **List of Selected Potential Small Hydropower Sites in Reconnaissance Stage in Cambodia in 2021**

Name	*Location*	*Capacity (MW)*
O Sla Downstream	Koh Kong	4.48
Phnom Batau Down Stream	Koh Kong	4.20
Stung Sva Slab	Kampong Speu	3.80
Phnom Tunsang Upstream	Koh Kong	3.14
Phnom Tunsang Down Stream	Koh Kong	3.00
Phoum Kulen	Siem Reap	1.56
Tum Nup Garaing	Siem Reap	1.50
Stung Prey Klong	Pursat	0.89
Preak Antap	Kampong Cham	0.84
Stung Boribour	Kampong Chhang	0.81
Prek Toeuk Chhu	Kampot	0.7
Upper Stung SiemReap	Siem Reap	0.66
Preak Thum	Siem Reap	0.51
Stung Bannak	Kampong Chhang	0.40
Stung Moung 1	Battambang	0.40
Stung Moung 2	Battambang	0.40
O Sam Kaong	Siem Reap	0.33
Pteak Kaoh Touch	Kampot	0.32
Kball Chay	Sihanoukville	0.31
Stung Tras	Kampot, Kampong Speu	0.24

Source: MME[14]

RENEWABLE ENERGY POLICY

Although the Government has issued policies and regulations for the energy sector, some of which are linked to renewable energy including SHP, no national target for renewable energy utilization has been set yet.[15] According to the Power Development Plan, renewable energy is expected to account for more than half of the country's total energy production by 2020. In general, the renewable energy policy in Cambodia is directly related to rural electrification. In 2004, the Government issued a Royal Decree for the establishment of the Rural Electrification Fund (REF) to accelerate the development of electric power and renewable energy supply in rural areas. Among other objectives, REF aims to promote and encourage private sector participation in providing sustainable rural electrification services such as the development and economic application of technically and commercially proven new and renewable energy technologies.[17]

In 2006, the Government approved the Rural Electrification by Renewable Energy Policy with the main objective of creating an enabling framework for renewable energy technologies to increase access to electricity in rural areas. The Rural Electrification Master Plan (REMP) is the guiding document for the implementation of projects and programmes towards this goal.[17] To ensure power supply in the country in the future, MME has prepared two master plans titled the Power Development Master Plan in the Kingdom of Cambodia for 2020–2030 and the Long-Term Power Master Plan for 2020–2040, studied by Chugoku Electric Power Co., Inc and Intelligent Energy System Pty, Ltd, respectively.

The Government has provided guaranteed payments to several hydropower projects; however, such incentives are not available for other types of renewable energy such as biomass and solar power. The solar power market has been predominantly driven by the electricity needs of people who are unable to access on-grid electricity. Increased solar photovoltaic (PV) installation is also stimulated by the two programmes implemented by REF and MME, which are the Solar Home Systems (SHS) Programme and the Power to the Poor (P2P) Programme funded by the World Bank and the French Development Agency (AFD), respectively.[17]

It is reported that climate change will lead to an almost 10 per cent reduction of the Gross Domestic Product (GDP) of Cambodia by 2050. In response to this impact, a policy recommendation to climate change adaptation regarding renewable energy is to focus on investment into solar power for a total capacity of over 700 MW, including utility-scale, roof-top, solar battery mini-grid and solar home systems. It is estimated that this measure can directly abate 8.7 million tons of CO_2 by 2045.[18]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The licensing system and procedure for hydropower projects in Cambodia is as follows:

- An IPP investor proposes a project plan to MME, the Cambodian Development Council (CDC) and MEF for obtaining a concession agreement for its development and providing an electricity service. The IPP also has to reach an initial agreement on the power purchase agreement (PPA) with EDC, after which EDC submits a draft PPA to EAC setting a power tariff and purchase conditions.
- After finalizing the agreement on the PPA between the IPP and EDC, EAC will issue a licence to the IPP to generate and sell electricity to EDC.

- Prior to the commencement of commercial operation of an electricity generating project, the IPP project, project operator and EDC jointly develop operating procedures.

However, all existing SHP plants in Cambodia were constructed with grant aid from the Government of Japan and were granted a generation licence and a consolidation licence by EAC.[19]

There are two regulations on the environmental impact assessment (EIA) in Cambodia: Initial Environmental Impact Assessment (IEIA) and Detailed Environmental Impact Assessment (EIA or Detailed EIA). For hydropower projects with a capacity of over 1 MW, the Detailed EIA is required.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

In general, SHP plants are more sensitive to climate change compared to larger hydropower due to their smaller scale. In 2014, the International Panel on Climate Change (IPCC) reported that South-Eastern Asia, and Cambodia specifically, has already been experiencing long-term changes in climate and is plausibly vulnerable and exposed to this impact.[3] Climate change imposes severe stress on ecosystems with far-reaching consequences, such as extreme climate events, including floods and drought among others. In turn, this influences the country's economic development, including electricity generation development. The impact of climate change on the development of SHP in terms of electricity generation are not uniform over different spatial scales such as local hydrological and geographic conditions. In comparison with other regions, the potential change in hydropower generation in Asia is linked to runoff. As such, small changes in climate conditions can lead to relatively large changes in SHP generation.

Hydropower operation and management should be properly optimized to correspond to any climate variations in the future. Particularly, an in-depth risk analysis of climate change impact on hydropower generation should be conducted and emergency plans for climate extremes should be prepared. Also, reservoir-based SHP plants should be considered for the future water infrastructure development as opposed to run-of-river plants.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

To attract more investors and reduce the risk of investment in SHP in Cambodia, there is need to refine investment costs, collect hydrological data and mitigate social and environmental impacts to make projects more technically and economically sustainable. To promote the decentralized, demand-driven approach in electrification and facilitate private sector involvement in SHP development, a number of barriers have to be overcome, including the following:

- High project costs. SHP is usually located in remote areas with limited access and far away from load centres, which implies the need for additional investment in infrastructure.
- Lack of a policy and legal framework. A policy and legal framework need to be created, e.g., concessionary duties and taxes concerning imports of SHP equipment.
- Access to financing for SHP projects. Banking and financial institutions operating in Cambodia provide credit for short periods with high interest rates ranging from 10 to 20 per cent per year, which impacts the financial viability of projects.
- Lack of energy market data. There is insufficient information available on the characteristics of the energy market, including the scope, potential and consumer characteristics. Few systematic studies exist for the potential of SHP resources in the country. There is also a need to conduct a more detailed financial analysis for investment purposes.
- Institutional capacity for planning, implementation and operation. There is a significant lack of technical knowledge and operational skills in the country. The lack of experience in operation and management as well as limited training possibilities are some of the factors causing institutional roadblocks. The lack of coordination among stakeholders (governmental agencies, development partners, non-governmental organizations, private investors and financial institutions) is another difficulty.

Taking into account that there remains untapped SHP potential in the country, further SHP development could be supported by the following:

- Grants from organizations and institutions;
- Lower interest rates for long-term loans from Cambodian banks and financing institutions;
- Lowering project costs via government support through REF if applicable and financeable, while EDC has so far supported private electricity suppliers in rural areas with accessing funds for investment in the expansion of electricity supply infrastructure in order to allow all rural households to have access to electricity;
- An improved policy and legal framework;
- Training of human resources with additional support from experts and relevant line ministries through either state or EDC funding;
- Capacity building in relation to SHP planning, construction, management, operation and maintenance;
- Ensuring that new SHP projects cause no or minor environmental and social impact, but rather improve the quality of life for communities living in vicinity of the projects.

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Indonesia

Vicky Ariyanti, Indonesia National Committee on Large Dams and Ministry of Public Works and Housing

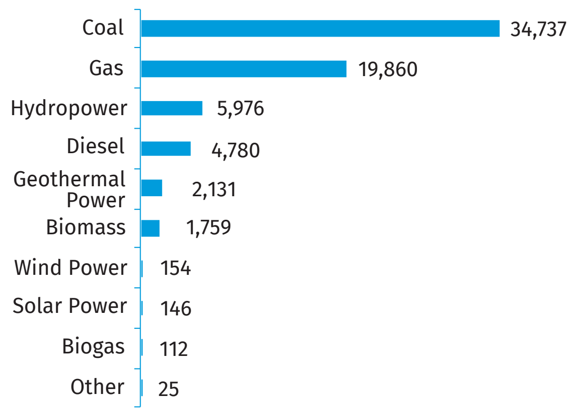
KEY FACTS

Population	270,625,568 (2019)[1]
Area	1,919,317 km^2 [2]
Topography	Indonesia is an archipelago made up of 13,667 islands, of which 6,000 are inhabited. The main islands are Sumatera, Java, Sulawesi, Kalimantan and Papua. The first three islands are located in the volcanic Pacific Ring of Fire, which stretches to the Philippines and Japan. The highest peak is Puncak Jaya (4,884 metres) located in the easternmost province of the country, Papua. Indonesia is affected by land subsidence in the cities of Medan, Jakarta, Bandung, Blanakan, Pekalongan, Bungbulang and Semarang as well as in the Sidoarjo Regency. The phenomenon is particularly worrying in highly populated coastal areas, which present the fastest subsidence rate and are also particularly vulnerable to flooding. The capital, Jakarta, is the fastest sinking city in the world by an average of 1–28 cm a year. The impact is most apparent in North Jakarta, with its lowest point at 4 metres below sea level.[2,3,4,5]
Climate	Indonesia is transected by the equator and has a tropical climate, with high humidity and high temperatures. Temperatures range between 23 °C and 31 °C, with the average being 28 °C. There are two seasons: the wet season which lasts from September to March and the dry season which lasts from March or June (depending on the area) to September. Indonesia is not often hit by typhoons, but does experience droughts caused by El Niño as a five-year-cycle periodic climate condition.[6]
Climate Change	Climate change impacts the Indonesian Archipelago, resulting in a shorter rainy season, which is characterized by more torrential downpours and an overall 12 per cent increase in rainfal.[7]
Rain Pattern	Precipitation patterns vary from island to island and are affected by the topography and wind patterns. Precipitation variations are usually from 1,300–3,200 mm in lowlands to 6,100 mm in the mountains, with the average annual rainfall of 2,700 mm.[2]
Hydrology	Water sources in Indonesia range from surface to groundwater. Rivers and springs are still mainly used for irrigation and drinking water supply. In the karst area in Java, underground rivers are also used as water sources. The country's main rivers are located in Kalimantan, Java, Papua and Sumatra. They are also used as a transport network. The longest river is the Kapuas (1,143 km) in Kalimantan, which flows from the northern-central mountains into the South China Sea.[2]

ELECTRICITY SECTOR OVERVIEW

In 2019, the installed capacity of Indonesia reached 69,679 MW, of which renewable energy sources accounted for 10,302 MW (15 per cent) and fossil fuels for 59,377 MW (85 per cent). Coal remains the main source of electricity generation in the country, accounting for nearly 50 per cent of the total installed capacity (Figure 1). In 2019, total electricity generation stood at 278,502 GWh. The state-owned company Perusahaan Listrik Negara (PT PLN) accounted for approximately 69 per cent (193,543 GWh) of the total, whereas 84,958 GWh was bought by the company from other producers.[8]

Figure 1. **Installed Electricity Capacity by Source in Indonesia in 2019 (MW)**



Source: ESDM[8]

The goal of the Government is to reach a 99.7 per cent electrification rate by 2025.[9] In 2019, the electrification rate reached 98.9 per cent, which represents an 18.4 percentage point increase from the 2013 levels.[8] This has been achieved due to the emphasis placed on electrification by the Ministry of Energy and Natural Resources (ESDM), through the laws UU No. 30/2007 on Energy and UU No. 30/2009 on Electricity as well as the regulation Permen No. 4/2020.[10] Electrification inequality no longer represents a significant issue in Indonesia. However, in eastern Indonesia, in the East Nusa Tenggara and Maluku Provinces, the electrification rate is still lagging behind other regions at 85.8 per cent and 91.3 per cent, respectively. Nonetheless, these numbers are in stark contrast with the data reported in the *World Small Hydropower Development Report (WSHPDR) 2019*: 47.8 per cent and 58.9 per cent, respectively. On average, the rest of the regions have already reached an electrification rate of 95 per cent. Furthermore, the majority of the islands have a 100 per cent electrification rate and in rural areas nearly all villages in all provinces of the country have also reached a 100 per cent electricity coverage (Table 1).[8]

Table 1. **Rural Electrification Rates in Indonesia in 2015–2019**

Year	*Villages electrified*	
	Total	*Share of the total*
2015	79,680	96.95%
2016	79,689	96.96%
2017	79,808	97.10%
2018	81,683	99.38%
2019	83,003	99.48%

Source: ESDM[8]

The Government has established a target to add 35.6 GW of new installed capacity by 2025, which represents an additional 23 per cent increase from the 29 GW that have already been put into operation.[11] In 2016, the 2016–2025 Electricity Supply Business Plan (Rencana Umum Penyediaan Tenaga Listrik) set out the independent power producer (IPP) scheme to facilitate the development of the sector.[12] An independent assessment performed at the end of 2019, showed that there had been only a 10 per cent progress towards the set target (3.6 GW), with an additional 57 per cent of the target capacity being under construction (20.1 GW).[13] However, there are positive expectations for the results of the programme.

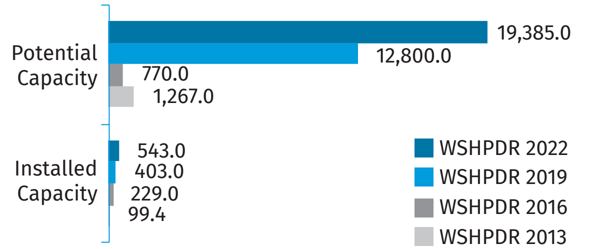
The Government plays an important role in setting electricity tariffs. The decision-making on tariffs is based on negotiations between the legislative and the executive bodies, rather than on objective decisions made by the PT PLN.[14] There are four groups of electricity consumers: residential, business, industrial and others divided into 12 subgroups.[13] The Government has heavily subsidized electricity tariffs, particularly for low-income households during the COVID-19 pandemic, and subsidies continue to be available. The Government provides subsidies of 100 per cent for 450 VA use and 50 per cent for 900 VA use.[15] The lowest tariffs are found in the Java-Bali power grid (0.07 USD/kWh), while the highest are in remote areas and small islands (0.21 USD/kWh).[16] In 2021, tariffs varied from 996.74 IDR/kWh (0.07 USD/kWh) to 1,444.70 IDR/kWh (0.10 USD/kWh). The subsidized tariffs since March 2021 are at 169 IDR/kWh (0.01 USD/KWh) for 450 VA and 274 kWh (0.02 USD/kWh) for 451-900 VA.[17] In 2019, tariff subsidies have slightly decreased from IDR 58.04 trillion (USD 4.02 million) in 2016 to IDR 51.71 trillion (USD 3.58 million).[8] The 2021 National Budget (APBN) also indicates that the subsidy allocations should be lower than in 2020.[18]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Indonesia is a combination of micro- (under 1 MW) and mini-hydropower (1–10 MW).[13] Most of SHP plants in the country are located on rivers or irrigation channels.[8]

In 2020, the total installed capacity of SHP was 543 MW from 185 listed SHP plants.[19] Compared to the *WSHPDR 2019*, the installed capacity increased by almost 35 per cent, whereas the potential grew by 51 per cent (Figure 2). The potential capacity of at least 12.8 GW reported in the previous edition was based on the PT PLN 2012 preliminary research.[20] Recently the ESDM published more detailed data from 2019, suggesting a higher hydropower potential: 74,656.5 MW for large hydropower and 19,385 MW for SHP.[21] It should be noted that the calculations do not account for off-grid SHP installations used on a small scale, from the village level to household generation, with capacity so low as to only light one house using the flow of an irrigation channel.

Figure 2. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Indonesia (MW)**



Source: PT PLN,[19] ESDM,[21] *WSHPDR 2013*,[22] *WSHPDR 2016*,[23] *WSHPDR 2019*[24]

Data on SHP development have improved as more attention has been paid on the policy level to developing renewable energy sources. In 2019, new SHP plants were installed across Indonesia with a combined capacity of approximately 162.2 MW. Due to increased interest in SHP, multiple feasibility studies have been conducted in recent years, with new SHP sites discovered.[21] In 2019, new mini-hydropower plants with capacity between 710 kW and 2,024 kW were built in several provinces.[13] In 2020, more projects were built, adding 58.8 MW to the total installed SHP capacity in the country, including: Lawe Sikap (7 MW), Wampu (9 MW), Kincang I (0.35 MW), Sinagma Unit 4 (0.2 MW) and Lakip.[25] Overall, in Indonesia SHP is considered to be a promising renewable energy source, especially for the development of off-grid locations, such as secluded islands or rural areas.

RENEWABLE ENERGY POLICY

The 2016 Nationally Determined Contribution (NDC) of Indonesia to reducing greenhouse gas emissions outlined the country's target of cutting the emissions by 26 per cent by 2020.[26] This target was later changed in 2017 to 29 per cent to be reached in 2020 and to 41 per cent in 2030.[27] The country has increased its budget for climate adaptation and mitigation efforts, including fiscal policies to reduce emissions in energy and land use. A 2017 study found that these efforts would not be enough to meet the country's climate commitments.[27] However, there is mitigation potential in the country's forest moratorium policy. Above all, the country needs to prioritize implementing renewable energy policies and improving private and public collaboration in this sector.

The renewable energy policy strategy is based on the ESDM Regulation No. 12/2017 concerning the utilization of renewable energy for electricity provisioning and improved electricity access in the coming 10 years. It is estimated that with the help of the IPP scheme 210 GW of total renewable energy potential could be developed. This potential consists of solar PV, biogas, large hydropower, waste, wind power, geothermal power, biomass, biogas and micro-hydropower. Renewable energy investment opportunities in Indonesia are largely dominated by the solar PV potential, whereas large hydropower is seen as the second key source. Conversely, SHP is not seen as a major contributor.[11] Incentives to support investment in renewable energy include financial loans with interest below market rates and fiscal incentives such as tax holidays, tax allowances, exemptions on import duties and VAT.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The recently-adopted ESDM Regulation No. 4/2020 stipulates that dams and irrigation channels built by the Ministry of Public Works and Housing (MPWH), regardless of size, are approved directly by the Minister under the commission of PT PLN and its subsidiaries.[28] This new policy was introduced in coordination with the MPWH strategic plan for 2020–2024, which establishes a progressive target. In 2019, it planned for the construction of 61 dams and 1 million ha of new irrigated lands. An additional 500,000 ha are planned by 2024, which will have an impact on irrigation channels all over the country as sources of SHP generation.[29] There are expectations that these policies will increase investment in SHP projects during the 2020–2024 period.

The current policy is geared towards the development of renewable energy, providing a significant tariff reduction due to a big price difference between the SHP plant's first and eighth years of operation. The ESDM's Regulation No. 4/2020 supports feed-in tariffs (FITs) for SHP up to 10 MW by PT PLN via the IPP scheme.[11] The Government also made open calls for these types of investment.[16] Furthermore, the prospect of the IPP scheme for SHP opened up possibilities for foreign direct investment in Indonesia. At present, funding comes from both the Government and private investors. Purchase obligation through direct selection for SHP-produced electricity is determined and uses a minimum capacity factor of 65 per cent.

COST OF SMALL HYDROPOWER DEVELOPMENT

Based on 2020 data from the ESDM, the investment cost for the development of SHP projects averages USD 2 million per MW.[25] The ESDM also stated that most SHP projects developed by PT PLN have a capacity between 0.2 MW and 10 MW, with an average of 3.9 MW. However, the higher the installed capacity, the lower the investment ratio per MW.

The high cost of SHP development results from the high imported content for the projects. However, Regulation No. 54/2012 of the Ministry of Industry, as amended by 5/2017 on Use of Domestic Products for Development of Electricity Infrastructure, stipulates the minimum domestic content requirement for renewable energy projects.[30] This regulation applies to all renewable energy projects carried out by state-owned enterprises, regional government-owned enterprises, cooperatives and private companies. However, according to the ESDM, the country's domestic industry cannot yet meet the above targets for local content. In 2018, for example, local content for hydropower projects between 15 MW and 150 MW only reached 33.8 per cent compared to the established target of 59.9 per cent.[31]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

There are different mechanisms available for funding SHP projects under the mini- (1–10 MW) and micro-hydropower (< 1 MW) categories depending on the location. For the former category, the Government provides investment. For the latter, private companies can participate in a bid. This arrangement provides opportunities for investors, especially to finance off-grid SHP plants in remote islands.

Nevertheless, Regulation No. 44/2016 on List of Business Areas Closed to Capital Investment and Areas Open with Conditions set out a very restrictive regulatory system for foreign players to invest in the Indonesian market. In relation to power generation, the regulation also sets different foreign investment restrictions based on the type of hydropower. Thus, no foreign investment is allowed for micro-hydropower (< 1 MW), a limitation of 49 per cent is set for mini-hydropower (1–10 MW) and a limitation of 95 per cent for large hydropower (> 10 MW).

Furthermore, all renewable energy projects that sell their electricity to PT PLN must be in a build-own-operate-transfer structure (BOOT). Developers must transfer their ownership to PT PLN at the end of the power purchase agreement (PPA), which forces developers to set higher prices during their PPA term. Therefore, it is important to compensate for the risk of negotiations with PT PLN to help deliver rapid deployment of renewable energy technologies in the country. One way could be to make it easier for developers to obtain long-term PPAs with guaranteed revenues.[31]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The COVID-19 pandemic has highlighted the impact of the climate crisis on Indonesia — with a slowing pace of human activity, the speed of climate change reduced and resulted in on-time seasonal patterns in 2020. Consumption rates also decreased in 2020, notably due to a reduction of the industrial sector activity.[32] This context has served as a wake-up call for the Indonesian Government to increase the share of renewable energy sources in the country's energy mix. PT PLN, as the lead of SHP development, showed consistent will for acquiring all kinds of power generation, especially those coming from renewable sources and, thus, set a successful example for other smaller and local companies or IPPs to pursue SHP development.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Despite the policies supporting SHP development in Indonesia, there are still significant barriers in place:

- Institutional frameworks that are still too general and institutional capacities that are not yet developed. The mechanism of receiving SHP permits still lacks transparency. In practice, the management of institutions is susceptible to changes in the political situation. The renewable energy policy framework established in 2020 will demonstrate whether it is sufficiently strong to put forward an agenda to support SHP initiatives.
- Unclear procedures for obtaining SHP development permits for private companies, especially for micro-hydropower, which might be explained by permit overlaps in the river basin management. For example, if the surface water resource is from an irrigation channel or weirs, it is complicated to determine which level of authorities will offer a mandate and release a permit for technical recommendations.[32]
- The quality of efforts in implementing the financial mechanism is also rather discouraging, with the fiscal and incentive mechanisms not yet implemented effectively. The lack of such mechanisms is, basically, due to the inflexibilities of budgeting schemes in the Government sectors. The investment of USD 2.0–2.5 million per MW is required; however, this amount is too low for project financing and too high for most actors in the private sector.
- The conditions for foreign investment need relaxation, especially for micro-hydropower. The investment for SHP projects at USD 2 million per MW is too high for most Indonesian start-up companies, but low for national level companies. The limitation on foreign ownership (49 per cent for SHP of 1–10 MW) is also making such investment less attractive.[19]
- Lack of standardization of PPAs and procurement processes. Although the current policy setting already indicates the mechanism, it still results in unbalanced agreements and reduces the reliability for investors.
- There is little incentive to develop SHP due to low awareness of the country's SHP potential, as well as limited equipment availability and limited infrastructure in rural areas. Overall, the benefits of off-grid electricity generation remain untapped in the Indonesian power system. The production by remote SHP plants lacks social support, and grid interconnection points are still insufficient for off-grid generation. Therefore, more effective power system planning is required, i.e., using an application that could back up the monitoring of the power grid scheme and off-grid generation in a single system.
- The current requirements of the BOOT scheme for project management are counterproductive, as are the procurement and contracting processes, negotiation practices as well as ownership restrictions, which should be changed towards a flexible modality of project financing.
- Aside from the restriction on foreign investment, the high local content requirements limit the ability of direct and fast implementation of SHP projects, especially in the case of latest technologies, which may not be produced in Indonesia.
- Access to basic data such as hydrometeorology, topography or geology should be made publicly available for any stakeholders. Furthermore, the available data sometimes lack reliability, especially in remote areas where data for precipitation are still manually recorded and can only cover a period of the last 20 years.

Despite these barriers, since 2017, the SHP sector has experienced a positive increase from 403 MW to 543 MW of installed capacity in 2020. The main obstacles identified are complex permitting procedures, the restriction of foreign investment as well as limited mechanisms for the further development of projects.

Nonetheless, with the enforcement of new regulations, it is expected that more attention will be paid to the benefits of SHP and the interest of the private sector to invest in hydropower will increase. The key enabling factors for SHP development in the country are:

- Significant undeveloped potential;
- Policy system conducive to further SHP development, including the FIT programme.

Further SHP development in the country could be facilitated by ensuring the following:

- Better data availability on SHP potential, especially in remote areas and smaller islands in the archipelago;
- A healthier investment atmosphere provided by the Government, including social stability and support to foreign investors in collaborating with local investors, which will enable the BOOT scheme to run, but with some flexibilities in terms of ownerships;
- Higher transparency in relation to technical requirements and the process of obtaining water usage permits.

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Lao People's Democratic Republic

Julian Chin, M8 Partners - Mekong Eight Group Co. Ltd

KEY FACTS

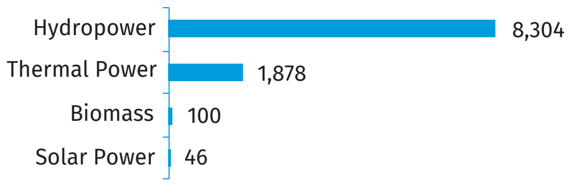
Population	7,275,556 (2020)[1]
Area	236,800 km^2 [2]
Topography	The topography of Laos is mountainous in most parts of the country. The Annam Range extends along the border with Viet Nam, rising to 2,817 metres at Phou Bia, the highest point in the country. The Tran Ninh Plateau in the north-east reaches heights of between 1,020 metres and 1,370 metres and the Bolaven Plateau in the south rises to 1,070 metres. Plains predominate in the south and central parts of the country along the Mekong River on the country's western border.[3]
Climate	Temperatures in Lao PDR are high throughout the year in most parts of the country, reaching a maximum of 35–38 °C and a minimum of 16–18 °C, with average daytime temperatures of 29–35 °C. In the subtropical northern regions, the temperature range is wider due to the occasional penetration of cold air from China and Siberia during the dry season and temperatures may occasionally drop to 0 °C in the highlands.[2,4]
Climate Change	Impacts of climate change are already being observed in Lao PDR in the form of more frequent extreme weather events and an increasing length of the dry season. Decreases in rainfall have been observed in many parts of the country, reaching 41 per cent in the Nam Ou basin during the first six months of 2019 relative to the same period in 2018. At the same time, a future increase in rainfall of 10–30 per cent is expected throughout the region, with wider differences in precipitation between wet and dry years.[5,6]
Rain Pattern	Rainfall in Lao PDR is driven by the monsoon climate, with two distinct seasons: a rainy season from May to October and a dry season from November to April. The average annual rainfall ranges between 1,400 mm and 2,500 mm in most parts of the country and exceeds 3,500 mm in the central and south-western regions.[4]
Hydrology	The largest river in the country is the Mekong, with 90 per cent of the territory of Lao PDR located within its drainage basin and contributing 35 per cent of the river's total flow. There are 39 tributaries of the Mekong within the country, of which 11 have a basin area of over 2,000 km^2 and a watercourse length of over 100 km. The total renewable water resources of the country are estimated at 333.5 km^3/year.[7]

ELECTRICITY SECTOR OVERVIEW

The electricity sector of Lao PDR is dominated by hydropower generation and national energy policy is oriented towards electricity exports. Total installed capacity of Lao PDR amounted to 10,328 MW as of January 2021, with hydropower providing 8,304 MW (80 per cent), thermal power from one coal-fired power plant providing 1,878 MW (18 per cent), biomass providing 100 MW (1 per cent) and solar power providing an additional 46 MW (less than 1 per cent) (Figure 1).[8,9]

The key public players in the energy sector are the national electricity regulator Électricité du Laos (EDL) and its spinoff company EDL-Gen, overseen by the Ministry of Energy and Mines (MEM). EDL oversees the domestic supply of electricity generated by plants operated directly by EDL and EDL-Gen as well as by independent power producers (IPPs) who contract with EDL-Gen. In recent years, most electricity generated in the country has been produced by IPPs, primarily for export. Lao PDR exports approximately two thirds of its domestic electricity production, although licensed IPPs are required to reserve a minimum of 10 per cent of their installed capacity for domestic markets.[10,11,12]

Figure 1. **Installed Electricity Capacity by Source in Lao PDR in 2021 (MW)**



Source: Chin,[8] Vientiane Times[9]

Total generation amounted to 39,967 GWh in 2020. Of this total, EDL and EDL-Gen were responsible for 2,821 GWh, while IPPs produced 37,145 GWh, with 16 IPPs under contract with EDL-Gen accounting for approximately 3,747 GWh.[11,13] Electricity exports in 2020 amounted to 31,468 GWh, with 2021 exports expected to reach 33,400 GWh.[9] Electricity demand has been increasing continuously since 2010 and is expected to reach 24,057 GWh by 2025 and 32,923 GWh by 2030.[14,15] Access to electricity in Lao PDR reached 100 per cent in 2019.[16]

The export of electricity is a key strategic direction for Lao PDR. The landlocked nation shares immediate borders with Myanmar, Thailand, Cambodia, Viet Nam and China, benefiting from the growth dynamics of those economies. For the last two decades, the Government of Lao PDR has actively used its policies and public statements to position Lao PDR as the premier electricity exporter in the South-Eastern Asia region, aiming to capitalize on the country's abundant hydrological resources.[17]

As the country lacks domestic financial infrastructure and human resource capacity to undertake complex engineering projects, recent developments in the power generation sector have relied on foreign direct investments, mostly through build-operate-transfer (BOT) concessions awarded to IPPs. However, transmission infrastructure remains predominantly Government-controlled, with limited connectivity between the country's four key subgrids (northern, southern and central No. 1 and No. 2). Policy on transmission infrastructure investment continues to evolve, with the China Southern Power Grid Company becoming the first foreign partner to establish a strategic relationship with the national regulator in this area.

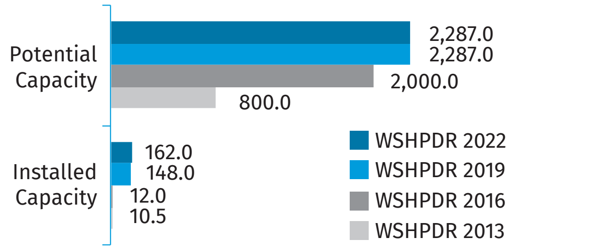
Recent development of the power sector in Lao PDR has included the completion of four new hydropower plants in 2020 despite the ongoing Covid-19 pandemic, adding 537 MW of installed capacity and a further annual generation potential of 2,139 GWh.[9]

Electricity tariffs in the country are set by EDL, with input from MEM as well as the Central Bank of Lao PDR. The current tariff structure stems from a 2008 study by SNC-Lavalin and was due for a review in 2018. However, the results from the review have not yet been formalized, partly due to the disruptions caused by the Covid-19 pandemic. End-user tariffs remained at 2017 levels as of 2021, with residential users paying approximately 50 USD/MWh.[18]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Lao PDR historically includes hydropower plants with installed capacity of up to 15 MW.[19] As of 2019, the total installed capacity of SHP up to 15 MW in the country amounted to 162 MW, while the estimated potential capacity equalled 2,287 MW.[10,20] Compared with the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity increased by nearly 10 per cent due to the commissioning of new SHP plants, while potential capacity has remained the same as no new estimates have been produced.[20]

Figure 2. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Lao PDR (MW)**



Source: JICA,[10] *WSHPDR 2019*,[20] *WSHPDR 2013*,[21] *WSHPDR 2016*[22]

The active policy of the Government on promotion of electricity exports and hydropower development has had a marked effect on the growth of SHP in the country. As part of the attempts to balance development priorities, the Law on Electricity, as amended in 2011, decreed that hydropower projects below the 15 MW threshold would be classified as SHP and could be approved by provincial authorities. Furthermore, access to such projects would be effectively limited to local developers.[19] This created momentum in the SHP market, and led to a flurry of unsolicited SHP project proposals submitted by developers to provincial authorities and the issuing of a large number of development mandates.[23] Most of these mandates were confirmed following rushed feasibility studies, attached to power purchase memorandums signed with EDL. In contrast, development of pico- and micro-hydropower projects below 5 MW remained under the authority of the Government, along with the promotion of biomass and other renewable energy sources (RES). Table 1 provides a partial list of SHP plants constructed in Lao PDR in recent years.

Table 1. **List of Selected Existing Small Hydropower Plants in Lao PDR**

Name	*Location*	*Capacity (MW)*	*Type of plant*	*Operator*	*Launch year*
Nam Pheuk	Saysomboun	5	Run-of-river	NCG	2018
Nam Jao	Oudomsay	5	Run-of-river	DPS	2018
Champilik 35	Champassak	5	Run-of-river	Pasakon	2017
Nam Phai 2	Vientiane Province	3	Run-of-river	PCC	2016
Senamnoy 6	Champassak	5	Run-of-river	Phong-subthavy	2015
Nam Sen	XiengK-houang	5	Run-of-river	Bothong Inter	2014
Tadslane	Savannakhet	3	Run-of-river	SIC Manu-facturing	2012

Nam Yone	Bokeo	3	Run-of-river	Nam Yone PC	2011

Source: Chin,[8] JICA[10]

In 2012, approvals for SHP spiked by a factor of five over the previous year. Of the total identified SHP potential capacity of 2,287 MW, approvals for projects totalling 1,140 MW were issued between 2012 and 2014.[24] As of 2019, a total of 252 MW of SHP projects was under construction.[10] Tables 2 and 3 provide some examples of ongoing SHP projects and still undeveloped potential SHP sites in Lao PDR, respectively.

Table 2. **List of Selected Ongoing Small Hydropower Projects in Lao PDR**

Name	*Location*	*Capacity (MW)*	*Type of plant*	*Developer*	*Planned launch year*	*Development stage*
Nam Ngum Keng Kaun	Xieng khuang	1	Run-of-river	N/A	2022	Under construction
Houykapheu 1	Saravan	5	Run-of-river	Vientiane Automation	2022	Under construction
Nam Karp	Saysomboun	12	Run-of-river	PSG Group	2023	Under construction
Nam Samouy	Vientiane Province	5	Run-of-river	Sana Construction	2023	Under construction
Nam Ngom	Bolikhamxay	5	Run-of-river	SDCC Co Ltd	2024	Seeking financial close

Source: Chin,[8] JICA[10]

Note: Data as of 2019

Table 3. **List of Selected Potential Small Hydropower Sites in Lao PDR**

Name	*Location*	*Potential capacity (MW)*	*Type of site*
Houychampi Pakang	Champassak	15	New
Nam Sanan	Luangprabhang	5	New
Nam Song Sieng	XiengKhoang	5	New
Houychampi	Champassak	5	New
Donsom	Champassak	5	New

Source: Chin,[8] JICA[10]

Note: Data as of 2017

A catastrophic failure of the main dam at the partially completed Nam Ao SHP plant (12 MW) in 2017 set off a re-evaluation of the hydropower sector by the Government. A year later, another dam failure at the Xepian-Xenamnoy hydropower plant (410 MW) cemented the Government's resolve to review and enhance safety standards at all hydropower project sites.[25] These events culminated in the 2017 amendments to the Law on Electricity, which effectively disbanded the classification of SHP within the hydropower sector, mandating that all hydropower projects, including those with an installed capacity of 5 MW and above, be developed under the unified central authority of EDL.[10]

The key legislative policy which directly governs the development of the hydropower sector in Laos is the Law on Electricity. While the 2011 amendments to the Law on Electricity arguably completed the deregulation of the hydropower sector for mid-scale IPPs, they also had the effect of limiting access to SHP projects up to 15 MW to local developers only. The subsequent amendments adopted in 2017, by removing the specially-regulated SHP designation, opened up hydropower projects of up to 15 MW to foreign investment, while concurrently elevating the standards for hydropower risk management. The amendments also triggered a revision of the key protocols for project development – the Lao Electric Production Technical Standards (LEPTS-2018). The revisions were carried out as part of a concerted effort by multilateral donors to address concerns about dam safety standards in Lao PDR highlighted by the 2017 and 2018 dam failures.[26]

RENEWABLE ENERGY POLICY

Development of RES in Lao PDR falls under the national Renewable Energy Development Strategy (REDS-2011). The policy was drafted under the purview of MEM's Institute of Renewable Energy Promotion (IREP) with the support of multilateral donor agencies and intended to run until 2025.[27]

While one of core aims of REDS was to promulgate the diversification of the national energy mix, much of its focus was directed towards meeting rural electrification targets. Nonetheless, the policy provided a platform for the Government's promotion of new variable renewable energy sources (VRES), which included SHP below 5 MW.

As the national conversation was overshadowed by hydropower generation for export purposes, the position on VRES pivoted on how competitively such resources could be developed in the country. Due to the insufficient integration of the domestic transmission infrastructure and the lack of an effective feed-in tariff ecosystem, the traction of VRES on the energy market in Lao PDR has been limited. However, issues with seasonal supply of electricity due to climate change and increasing international pressure to commit to the decarbonization of the energy sector is forcing the Government to consider RES more seriously.[28,29]

COST OF SMALL HYDROPOWER DEVELOPMENT

Access to locations remains a fundamental issue for project development in Lao PDR, particularly during the wet season, when construction is often suspended. The remoteness of potential SHP sites as well as the historical context of rural development in Lao PDR have also meant that collecting baseline hydrological and geological data is often the responsibility of potential project developers themselves. As these data are not publicly available, meaningful cost benchmarking for SHP plants is not easily done. However, projects already in commercial operation broadly indicate a cost range of USD 1.3–2.0 million per MW of installed capacity. The parameters driving cost variability in Lao PDR include degrees of civil engineering complexity due to geological issues, project head profile, engineering and maintenance, choice of electro-mechanical (E&M) supplier and other factors.[8]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Options for financing SHP projects in Lao PDR are offered by a number of locally domiciled banking institutions. Such facilities are traditional non-recourse loans, backed by assets separate from the project itself, and typically offer up to 70 per cent of the project's developmental value, drawing a fixed interest in the range of 9–11 per cent (as of 2020). There is generally some scope for negotiation of preferential terms, however, and approvals are often tied to the contract for build construction. It is therefore commonplace for SHP projects in Lao PDR to follow the engineering, procurement and construction plus financing (EPC+F) models of larger hydropower plants.[8]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The impact of climate change on generation from hydropower in Lao PDR is already being felt. Drought conditions at the end of 2019 and delayed rains in 2020 led EDL-Gen to fall short of its generation plan for 2020 by approximately 13 per cent, while IPPs contracting with EDL-Gen experienced a generation shortfall of over 22 per cent.[11]

As a key riparian state in the centre of the Mekong River, Lao PDR is subject to the climatic effects of upstream flows from China, while being held responsible for the downstream effects flowing into Cambodia and Viet Nam (the greater Mekong subbasin). Due to the position of Lao PDR as a critical food bowl for multiple population centres, coupled with the country's ambitious transboundary power development plans, geopolitics related to water resources development in the region is necessarily complex and a multitude of competing influences vie for control over water. To address competing demands, the contemporary approach is to view water within the nexus of food security, energy and developmental needs.[30,31,32]

Particular urgency is given in Lao PDR to mitigating the direct risks to SHP plants associated with flash flooding events. Indirect risks include acute water shortages having an adverse impact on power production, agricultural harvest and community water demands. To this end, the Government is actively prioritizing the quality of construction and dam safety modelling, as well as hydrological modelling and basin-wide planning to mitigate these risks.[33,34]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

While there remains some potential for new greenfield sites, a large portion of the potential capacity for SHP up to 15 MW has already been earmarked for development. Many of these concessions are pending investment. However, as the Government enhances its level of planning and solicitation of project proposals, quality of partnerships with local parties, contract conditions and construction standards will play an increasingly important role in SHP development in Lao PDR. And while deregulation persists, there remain structural barriers within the sector which need to be overcome, including:

- Lack of sophisticated financing options available through the domestic financial system;
- Lack of integration between transmission networks to support project risk mitigation;
- Ongoing ambiguity relating to the rights of legacy projects;
- Limited domestic demand, with EDL being the single domestic power purchaser;
- Frequently changing legislative frameworks around asset ownership and securitization to facilitate loans and project financing;
- Absence of a targeted investment scheme specific to SHP, due to the removal of hydropower classification from the national framework.

Enabling conditions for SHP development in the country include:

- Strong momentum in the domestic hydropower sector as of 2021, with an increasing number of de-risked projects coming to the market seeking financial close;
- The Government's strategy to make hydropower a cornerstone industry;
- Integration of the national grid remains a key focus;
- Future energy demand growth remains strong as domestic and Greater Mekong Subregion grids integrate, bringing in new partnerships in the energy sector;
- Financial and technical support from donors and multilateral organizations are accessible;
- There are increasing technical resources and support services available in the domestic market, further driving down the cost of project development;
- Improved data collation will further refine the national power development plan, leading to greater clarity in project prioritizations;
- Ongoing consolidation of the national regulator EDL will lead to improvements in the quality of contracts and operational standards;
- There is growing appetite for multipurpose water resource applications vis-a-vis integrated water re-

source management projects within the scope of the developmental nexus. As such, SHP plants must also play a critical role in water and food security, conservation of biodiversity and rural development.

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Malaysia

Engku Ahmad Azrulhisham, Sustainable Energy Analysis Laboratory, Universiti Kuala Lumpur Malaysia.

KEY FACTS

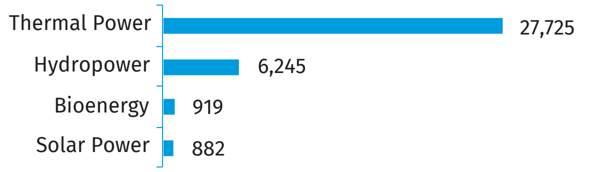
Population	32,720,000 (2019)[1]
Area	330,345 km² [2]
Topography	Malaysia is divided into three main regions: Peninsular Malaysia, Sabah and Sarawak. Sarawak and Sabah are located on the island of Borneo and are separated from Peninsular Malaysia by the South China Sea. Peninsular Malaysia shares a land border with Thailand and a maritime border with Singapore, while Sabah and Sarawak share land borders with Indonesia and Brunei. The topography of Malaysia is generally dominated by a mountainous core with half the land area lying at more than 150 metres above sea level. Elevations generally are less than 300 metres, but isolated groups of hills reach heights of 750 metres or more. The most prominent of these ranges is the Main Range, with peaks exceeding 1,200 metres. The highest peak is Mount Kinabalu of the Crocker Range, with an elevation of 4,101 metres. The terrain in the region is usually irregular, with steep-sided hills and narrow valleys.[3]
Climate	Malaysia has a tropical climate, without extremely high temperatures. Throughout the year, the average temperature ranges from 20 °C to 30 °C. Humidity is a common feature. Nights in Malaysia are fairly cool. Winds are generally light with mean annual speed of 1.8 m/s. However, towns in the east coast of Peninsular Malaysia, such as Mersing, Kota Baharu and Kuala Terengganu, experience stronger winds with monthly speed sometimes exceeding 3 m/s. Situated in the equatorial doldrums area, the territory extremely rarely enjoys a full day with a completely clear sky even during periods of severe drought. On the other hand, it is also rare to have a stretch of a few days with completely no sunshine except during the north-eastern monsoon season (November to March).[4,5,6]
Climate change	Temperature records in the past 30–50 years have shown changes in the range from 0.7 to 2.6 °C, while precipitation changes range from -30 to +30 per cent. Climate change in Malaysia has resulted in negative impacts such as changes in rain patterns, rising sea levels and subsequent coastal flooding and more frequent extreme weather events.[5]
Rain pattern	The seasonal wind flow patterns coupled with the local topographic features determine the rainfall distribution patterns over the country. The main rainy season in East Malaysia is characterized by heavy rains and runs between November and February, while August is the wettest period in Peninsular Malaysia. While Peninsular Malaysia receives an average rainfall of 2,500 mm, East Malaysia receives 5,080 mm of rain.[6]
Hydrology	Malaysia is drained by an intricate system of rivers and streams. The longest river, the Pahang, is only 563 km long. Streams flow year-round because of the constant rains, but the volume of transported water fluctuates with the localized and torrential nature of the rainfall.[7]

ELECTRICITY SECTOR OVERVIEW

In 2019, Peninsular Malaysia was 99.9 per cent electrified, with electricity being generated by power plants with a total installed capacity of approximately 26,030 MW (26,132 MW including the regional interconnection). The generation mix consisted of coal (12,066 MW), gas (11,000 MW), large hydropower (2,240 MW), solar power (429 MW) and small hydropower (SHP) (296 MW).[8] In 2020, Sarawak, the largest state in Malaysia, was 98 per cent electrified with an installed capacity of 5,222 MW. The energy mix in Sarawak was dominated by hydropower (3,452 MW), coal (1,102 MW) and gas (585 MW), with a further 84 MW from off-grid diesel and alternative energy sources.[9] Sabah, which is the second largest state in Malaysia, was 98 per cent electrified in 2019 with a dependable capacity of 1,277 MW from gas (968 MW), diesel (150 MW), large hydropower (81 MW), biogas/biomass (28 MW) and solar power (50 MW).[8] Total installed capacity in all states of Malaysia amounted to 35,771 MW in 2019 (Figure 1).[10] In 2019, Malaysia also benefited from a fully functioning regional power grid receiving 100 MW of power transfer from the Lao PDR via the Lao–Thailand–Malaysia (LTM) interconnection grid that is part of the ASEAN Power Grid.[8]

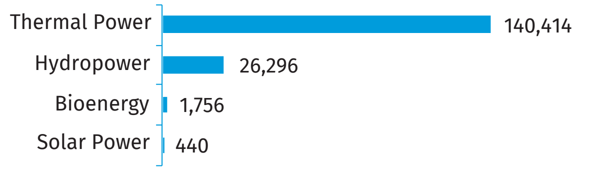
In 2018, electricity generation in Malaysia from all sources reached 168,906 GWh (Figure 2).[10] In 2019, the total electricity generation in Peninsular Malaysia increased by 2.54 per cent, to 130,009 GWh as compared to 126,790 GWh in 2018.[8]

Figure 1. **Installed Electricity Capacity by Source in Malaysia in 2019 (MW)**



Source: IRENA[10]

Figure 2. **Installed Electricity Generation by Source in Malaysia in 2019 (GWh)**



Source: IRENA[10]

In 2019, growth of the Malaysian economy slowed to 4.3 per cent compared to 4.7 per cent in 2018.[11] However, peak electricity demand increased by 1.2 per cent to 18,566 MW in Peninsular Malaysia, while in Sabah, demand grew by 4.8 per cent, reaching 1,001 MW.[8] The spike in demand in Peninsular Malaysia and Sabah was mainly attributed to hot weather conditions due the El Niño phenomenon.[8]

The country's continuing efforts to enhance energy security, affordability and sustainability have led to the implementation of a variety of initiatives that are also aligned with the national decarbonization and energy market liberalization goals. Since 2018, the country has seen an increase in renewable energy capacity as a result of the commencement of operations of Large-Scale Solar (LSS) and mini-hydropower projects, which contributed 429 MW and 296 MW, respectively. As of the end of 2019, a total of 21 large solar power plants had started commercial operations. In Peninsular Malaysia, renewable energy capacity recorded a fourfold increase from 179 MW in 2018 to 725 MW in 2019. Overall, as of 2019, renewable energy sources (excluding large hydropower) accounted for approximately 7 per cent of the total installed capacity in the country. This increase in the share of renewable energy in the energy mix is in line with the national target of achieving a 20 per cent share by 2025.[8]

As of 2019, a total of 1,449 MW of additional solar power capacity was awarded to 63 companies to develop large solar farms under the LSS Programme.[8] Solar power development was further boosted by a pricing policy revision for solar power produced by prosumers through the Net Energy Metering (NEM) scheme, which took effect on 1 January 2019. Under the revised scheme, prosumers can sell excess solar photovoltaic (PV) electricity to the grid on a one-on-one offset basis at Tenaga Nasional Berhad's (the national electric utility company) retail electricity tariff rates instead of on a displaced cost basis with lower tariff rates. As a result, 125 licences were issued in 2019 as compared to 37 licences in 2018.[8]

To facilitate renewable energy consumption, a premium tariff scheme for consumers wanting to buy green energy was introduced in 2019. The scheme provides consumers with the option of buying green energy from renewable energy sources with a premium of 0.08 USD/kWh without the need to install their own renewable energy generation system. Renewable energy capacity is also expected to be boosted following the Government's approval of a 10-year generation plan known as Malaysia Electricity Supply Industry 2.0 (MESI 2.0) for Peninsular Malaysia and Sabah, covering the period of 2020 to 2030. MESI 2.0 aims to liberalize the generation and distribution components of the power industry in Peninsular Malaysia as well as to better promote the use of green energy in Malaysia. The emphasis is on the promotion of solar power in Peninsular Malaysia and hydropower in Sabah.[8]

The share of fossil fuel-based generation is projected to decline from 82 per cent in 2020 to 70 per cent in 2030. While gas is expected to dominate the capacity mix for the period leading up to 2030, the prominence of coal in the energy mix will decline from 42 per cent in 2020 to 35 per cent in 2025. The share of gas in the energy mix by 2030 is projected to reach 41 per cent, compared to 29 per cent of coal, 7 per cent of hydropower and 23 per cent of other renewable energy sources.[8]

The electricity tariffs in Malaysia are determined by the Government through the Energy Commission. When it comes to residential tariffs, the rates in Malaysia are the lowest among five ASEAN countries (Malaysia, Singapore, Philippines, Indonesia and Thailand). For commercial consumers, only Singapore and Indonesia have marginally lower rates.[12] The residential tariffs can be seen in Table 1.

Table 1. **Electricity Tariffs in Malaysia in 2018**

Consumption category	*Tariff (MYR/kWh)*	*Tariff (USD/kWh)*
1 – 200 kWh per month	0.2180	0.053
201 – 300 kWh per month	0.3340	0.081
301 – 600 kWh per month	0.5160	0.13
601 – 900 kWh per month	0.5460	0.13
≥ 901 kWh	0.5710	0.14

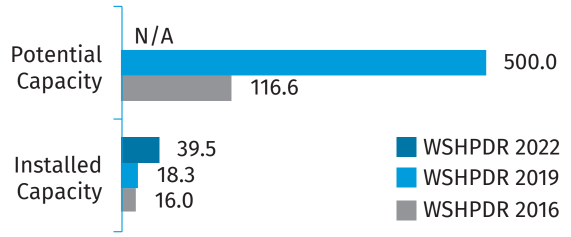
Source: Tenaga Nasional Berhad[12]

SMALL HYDROPOWER SECTOR OVERVIEW

Malaysian regulations classify SHP as run-of-river plants up to 30 MW in installed capacity.[13] In 2019, hydropower accounted for 17 per cent (6,245 MW) of total installed generation capacity in Malaysia, in which 4.7 per cent (296 MW) was contributed by SHP.[8] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP up to 30 MW increased 162 per cent as a result of the commissioning of new plants in recent years (Table 2).

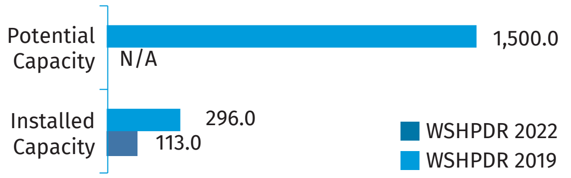
Additionally, new data on the estimated potential capacity of SHP up to 30 MW became available from the Malaysian Small Hydro Industry Association (Figure 3). No current data is available on the installed and potential capacities of SHP up to 10 MW (Figure 4).

Figure 3. **Small Hydropower Capacities up to 30 MW in the WSHPDR 2019/2022 in Malaysia (MW)**



Source: Energy Commission,[8] *WSHPDR 2013*,[14] *WSHPDR 2016*,[15] *WSHPDR 2019*,[16] SEDA[17]

Figure 4. **Small Hydropower Capacities up to 10 MW in the WSHPDR 2013/2016/2019 in Malaysia (MW)**



Source: *WSHPDR 2013*,[14] *WSHPDR 2016*,[15] *WSHPDR 2019*[16]

The development of major hydropower projects in Malaysia is generally undertaken by utility companies such as Tenaga Nasional Berhad (TNB) in Peninsular Malaysia, Sarawak Energy Berhad (SEB) in Sarawak and by Sabah Electricity Sdn Bhd (SESB) in Sabah. The adoption of SHP has been making progress in Malaysia, which has been spurred on by the implementation of the feed-in tariff (FIT) scheme under the Renewable Energy Act 2011.[18] Spearheaded by the Sustainable Energy Development Authority (SEDA), the FIT scheme offers investors in mini-hydropower plants the opportunity to sell electricity to the utility through the distribution grid system owned by the national utility company TNB through the standardized Renewable Energy Power Purchase Agreement (REPPA).[19]

From 2019, the FIT is to be limited to generation based on biogas, biomass, mini-hydropower and geothermal energy. In December 2019, under its e-bidding FIT programme for mini-hydropower projects, SEDA awarded quotas to 15 bidders for a total installed capacity of 176.79 MW, at an average bid tariff of USD 0.061 (MYR 0.259) per kWh. These projects are expected to start commercial operations in late 2025.[19]

Table 2. **List of Selected Operational Small Hydropower Plants in Malaysia**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Kota 2	Lawas region, Sarawak	12.00	222	Run-of-river	-	2020
Sungai Tersat Mini Hydro	Hulu Terengganu	4.00	-	-	TNB	2019
Sungai Pelus Small Hydro	Sungai Siput Perak	24.50	-	-	Pelus Hidro Sdn Bhd	2019
Sungai Selama Mini Hydro	Selama Perak	9.00	-	-	Selama Hidro Sdn Bhd	2019
Sungai Geruntum Mini Hydro	Kampar Perak	2.00	-	-	Conso Hydro renewable energy Sdn Bhd	2019
Sungai Korbu Mini Hydro	Sungai Siput Perak	7.00	-	-	Kuasa Sezaman Sdn Bhd	2019
Sungai Kampar Mini Hydro	Kampar Perak	5.25	-	-	Koridor Mentari Sdn Bhd	2019
Sungai Slim Mini Hydro	Batang Padang Perak	6.00	-	-	Zeqna Corporation Sdn Bhd	2019
Sungai Benus Mini Hydro	Bentong Pahang	5.00	-	-	Pasdeq Mega Sdn Bhd	2019
Bintang Hydroelectric	Selama Perak	14.00	-	-	Kerian Energy Sdn Bhd	2019
Sungai Gelinting Mini Hydro	Behrang Perak	2.20	-	-	Gelinting Hydro Sdn Bhd	2019
Lower Liang Mini Hydro	Raub Pahang	10.00	-	-	Contour Mechanism Sdn Bhd	2018
Upper Liang Mini Hydro	Raub Pahang	10.00	-	-	Trident Cartel Sdn Bhd	2018
Tembat Hydropower	Hulu Terengganu	15.00	-	-	TNB	2017
Sungai Perting Mini Hydro	Bentong Pahang	6.60	-	-	Amcorp Perting Hydro Sdn Bhd	2015
Sungai Rek Mini Hydro	Kuala Krai Kelantan	3.20	-	-	I.S. Energy Sdn Bhd	2013
Sungai Kerling Hydropower	Hulu Selangor	2.00	-	-	Renewable Power Sdn Bhd	2012

Name	Location	Capacity (MW)	Head (m)	Plant type	Operator	Launch year
Sungai Pangapuyan Mini Hydro	Kota Marudu Sabah	4.50	-	-	Esajadi Power Sdn Bhd	2011
Sungai Kadamaian Mini Hydro	Kota Belud Sabah	2.00	-	-	Esajadi Power Sdn Bhd	2011

Source: Energy Commission,[20] International Journal on Hydropower & Dams[21]

Table 3. **FIT-Awarded Small Hydropower Projects under Construction**

Name	Location	Capacity (MW)	Operator	Planned launch year
Sungai Singor Mini Hydro	Hulu Perak	27.0	Singgor Hydro Sdn Bhd	2021
Bengkoka Lower River	Kota Marudu Sabah	13.5	One River Power Sdn Bhd	2021
Bengkoka Upper River	Kota Marudu Sabah	10.0	One River Power Sdn Bhd	2021
Togohu River Small Hydropower	Kota Marudu Sabah	5.6	One River Power Sdn Bhd	2022
Geroh River Mini Hydro	Kampar Perak	2.0	Kundor Hydro renewable energy Sdn Bhd	2022

Source: SEDA[19]

An inventory survey of hydropower resources of the country was conducted in the mid-1970s and has since been used as indicative information of available hydropower resources within the country. The total gross potential for hydropower development is estimated at approximately 414,000 GWh per year, of which approximately 123,000 GWh per year is technical potential. Seventy per cent of this potential is located in Sarawak (87,000 GWh), 20,000 GWh in Sabah and 16,000 GWh in Peninsular Malaysia.[22]

According to the Malaysian Small Hydro Industry Association (MASHIA), the SHP potential capacity of the country is approximately 1,500 MW, of which 530 MW were in various stages of implementation as of the end of 2020. In the near term, given the focus on enhancing renewable energy generation in the country, SHP projects, such as pumped-storage hydropower and, to some extent, off-river storage systems, will make inroads into the market.[17]

RENEWABLE ENERGY POLICY

At the 2015 United Nations Climate Change Conference (COP 21), Malaysia is committed to reduce the greenhouse gas (GHG) emissions intensity of its Gross Domestic Product (GDP) by 45 per cent by 2030 as compared to 2005. The sources of GHG emissions in Malaysia comprise mainly conventional power plants and vehicles. In order to achieve the COP 21 target, Malaysia is actively pursuing initiatives on developing sustainable energy, substitution to cleaner fossil fuels and adoption of electric vehicle technologies.[17]
In developing sustainable energy, since the early 1980s Malaysia has taken several initiatives to diversify its energy sources and revenue streams away from oil. The country's first National Energy Policy adopted in 1979 was aimed at paving the way for an efficient, secure and environmentally sustainable supply of energy in the future.[23] In 1980, the National Depletion Policy was established to conserve the country's resources by limiting the utilization of crude oil and gas. Since oil remained the main source for energy supply, the Four Fuel Diversification Policy of 1981 was formulated to balance the contribution of other resources, including gas, hydropower and coal, into the energy mix.[24]

The Five Fuel Diversification Strategy was formulated under the Eighth Malaysia Plan (2001–2005), in which biomass, biogas, municipal waste, solar PV and SHP were recognized as potential renewable energy resources for electricity generation. Renewable energy was introduced as the fifth fuel in the energy mix as a key initiative to ensure the development of a sustainable energy sector and to encourage the growth of renewable energy in Malaysia.[24]

To promote renewable energy as the fifth fuel, the Government launched the Small Renewable Energy Power (SREP) programme in 2001. Within the scope of this programme, small renewable energy power plants were regulated in order to contribute to the electricity grid network. In 2010, the Government launched the National Renewable Energy Policy and Action Plan (NREPAP), which incorporates the elements of the planned energy, industry and environmental policies to make them more convergent in nature. Subsequently, in 2011, the Renewable Energy Act was established to introduce a FIT and mechanisms for managing its implementation including the setup of SEDA to administer the overall process. The introduction of the FIT catalyzed a rapid growth of renewable energy as it minimizes the investment risk with the guarantee that developers will have access to the electricity grid network and long-term power supply contracts with the power utility company. The eligible renewable energy sources within this scheme are biogas, biomass, SHP, solar PV and geothermal power.[24]

The Eleventh Malaysia Plan (2016–2020) described a new energy policy with a major focus on exploring new renewable energy sources and further intensifying the development of renewable energy through the Net Energy Metering (NEM) and Large-Scale Solar implementation.[24] The NEM programme was updated to NEM 2.0 three years later by adopting the true net energy metering concept, which allows excess electricity generation with solar PV power to be fed back into the grid on a "one-on-one" offset basis. This has managed to reduce the period for return of investment to a mere three years especially for commercial and industrial installations, which also benefited from the various tax incentives provided by the Government. The initiatives are bearing fruit. Thus, SEDA approved a cumulative NEM programme quota of 108 MW as of the end of November 2019, which indicates a 7.8-fold increase compared with the previous three years, when the quota stood at only 13.86 MW. As of November 2019, a total of 751.21 MW of capacity had been installed under the FIT and NEM programmes.[19]

Besides the NEM programme for rooftop solar power, the Government introduced a Large-Scale Solar (LSS) programme in 2016. The total capacity allocated for LSS is 1,000 MW and is capped at 250 MW annually (200 MW for Peninsular Malaysia, 50 MW for Sabah). The programme lasted from 2017 to 2020. As of the end 2019, 21 LSS projects with a total installed capacity of 250 MW had been successfully installed and commercially operated.[25]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The outlook for the SHP sector is highly linked to the FIT system, which was legislated under the Renewable Energy Act 2011. The FIT system has dramatically improved the commercial viability of SHP in Malaysia by supporting the investors via a premium tariff range for electricity generated from SHP plants.

In 2019, SEDA moved away from a system of predetermined rates per kilowatt hour for SHP to an e-bidding system to distribute quotas based on competitive bidding. The aim of e-bidding is to facilitate price setting for renewable energy generated from SHP through competition. The first e-bidding exercise was held in September 2019 for a total quota of 160 MW of installed capacity. Successful bidders secured quotas within a price range of 0.23–0.26 MYR/kWh (0.056-0.063 USD/kWh).[22]

A company that has obtained a FIT approval from SEDA for SHP plants may apply to the Energy Commission, the regulator of the energy sector in Peninsular Malaysia and Sabah, for a provisional licence issued under the Electricity Supply Act (ESA). This is typically done to facilitate the development of a renewable energy project and to enable the operator to apply for financial incentives and programmes prior to the construction and operation of the facilities and is intended to ease the entry of new participants into the renewable energy market.[26] The ESA licence relates to the construction of power plants and power installations and to the supply, sale, distribution and transmission of electricity. Other ancillary licences and certifications from the Department of Environment of Malaysia and the Malaysian Department of Occupational Safety and Health may also be required in the process of obtaining the ESA licence and approvals from the Energy Commission.[26]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

There are a number of fiscal incentives in place that are specifically targeted at potential entrants into the renewable energy market in Malaysia including SHP project investors. For example, the Ministry of Energy, Science, Technology, Environment & Climate Change (MESTECC) has approved a budget of MYR 5 billion (USD 1.22 billion) under the Green Technology Financing Scheme (GTFS) to help fund new energy efficiency projects in Malaysia for the period of 2018–2022. Additionally, on 6 March 2019, the Ministry of Finance approved an upgraded scheme, GTFS 2.0, for companies that are majority Malaysian-owned, allocating MYR 2 billion (USD 490 million) for the period between January 2019 and the end of 2020. GTFS 2.0, which is to last for two years, offers successful applicants an interest/profit rate subsidy of 2 per cent per year on loans and financing for the first seven years of the financing term and a Government-issued financial guarantee of 60 per cent of the green component cost. As of the end of 2020, the official GTFS website listed 655 projects approved and certified for the GTFS scheme.[26]

The Malaysian Investment Development Authority (MIDA) also offers tax incentives for green technology projects and services. Subject to any other conditions imposed by MIDA, a Malaysian company that undertakes a green technology project, including an SHP one, or a company that purchases green technology assets as listed in MIDA's MyHijau Directory, may be eligible for an investment tax allowance of 100 per cent of the qualifying capital expenditure incurred from the year of assessment 2013 until the year of assessment 2020. Similarly, a Malaysian company that provides green technology services is eligible for an income tax exemption of 100 per cent of its statutory income from the year of assessment 2013 until the year of assessment 2020.[26]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

While solar power receives overwhelming attention in Malaysia, other investors look into other resources to boost their renewable energy portfolios. Of all the other renewable sources, SHP is rising to have the next best potential after solar power. Despite the overall benefits, Malaysia also appears to be facing a number of specific challenges in developing SHP including:

- Longer gestation period compared to other renewable sources due to difficult terrain and limited working season;
- Lack of hydrological data for analyzing the reliability of the plants;
- Construction challenges are present as projects may demand extensive civil works, especially if they are located in remote areas;
- Lack of adequate inter-grid connectivity, which poses obstacles for the evacuation of power;
- Control and diversion of water flows is subject to federal and state regulations, resulting in long periods

required for obtaining the many authorities and agencies' approvals.[27]

Notwithstanding the challenges and difficulties, the existing SHP potential is already translating into bidding interest. The enablers for SHP development in Malaysia include the following:

- In the current regulatory framework, SHP developers are not exposed to demand risk as fixed energy payments are their current sole source of revenue;
- The off-takers must accept and purchase all the electricity generated, up to a pre-specified quantity, known as the maximum metered renewable energy for SHP, as stipulated in the REPPAs. This priority of despatch enjoyed by SHP energy producers moderates the absence of fixed availability-based revenue, which is typically earned by thermal power plants;
- The operating requirements are also undemanding as SHP energy producers will only be penalized if they fail to deliver 70 per cent of their declared annual quantity.[28]

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Myanmar

Thet Myo, UNIDO Myanmar; Aung Thet Paing, Federation of Myanmar Engineering Societies

KEY FACTS

Population	54,409,794 (2020)[1]
Area	676,590 km^2 [2]
Topography	Topographically Myanmar can be divided into four main parts: the eastern highland region, the central valley region, the western hills region and the south-western costal region. The eastern highland region is dominated by the Shan Plateau, which reaches altitudes of 900–1,200 metres. The central valley region consists of a broad basin draining into the Ayeyarwady River. The western hills region is an extension of the Himalayan Range and is known as the Anout Yoma. Mount Khakabo Razi is a part of Anout Yoma and is 5,881 metres high. The south-western costal region, consisting of the Rakhine, Ayeyarwady and Taninthayi regions, is 1,930 kilometres long.[3]
Climate	Myanmar has a tropical monsoon climate. Climatic conditions vary widely depending on the location due to differing topographic characteristics. Myanmar has three seasons: the hot season from March to May, the wet season from June to October and the cool season from November to February. On average, temperatures in central Myanmar during the hot season can reach highs of over 40 °C, with highs of less than 30 °C in the north.[3]
Climate Change	Myanmar is widely considered one of the most vulnerable countries in the world in terms of the impacts of climate change. Climate change impacts have included more frequent and severe floods, cyclones and droughts, leading to tens of thousands of deaths and billions of dollars' worth of economic damage from extreme weather events in recent decades. Between 1981-2010, temperatures in the country had risen between 0.14 °C and 0.35 °C per decade, with climate change models projecting a 0.8-2.6 °C increase in maximum temperatures by 2100 under a moderate climate change scenario.[4,5,6]
Rain Pattern	Rainfall in Myanmar varies widely across seasons as well as regionally and is influenced by both the South Asian and East Asian monsoons. The nationwide annual precipitation average is estimated at 2,000 mm, while in the south-western costal region (the Rakhine coast) annual precipitation averages 3,200 mm and in the eastern highland region 1,400 mm.[3]
Hydrology	Myanmar has a favourable situation with respect to water resources. There are only a few transboundary rivers, with virtually all water resources located within the national borders. The Ayeyarwady River is the longest in the country at 2,063 kilometres and flows from north to south. The other major rivers are the Thanlwin (1,660 kilometres), the Chindwin (1,151 kilometres) and the Sittaung (310 kilometres).[3]

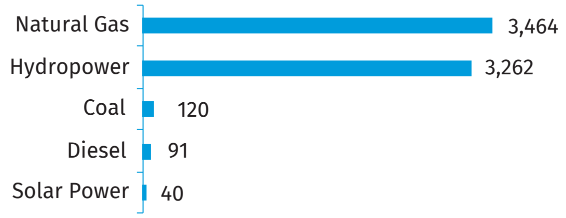
ELECTRICITY SECTOR OVERVIEW

Myanmar is endowed with abundant energy resources, particularly hydropower and natural gas, which are the main energy sources for electricity generation. Electricity demand has steadily increased in recent years, exceeding the available generation and transmission capacity. Consequently, Myanmar has the lowest electric power consumption among the member states of the Association of South-East Asian Nations (ASEAN).[2]

The total installed electricity capacity of Myanmar was 6,977 MW in 2020, consisting of 3,464 MW (50 per cent) from natural gas power plants, 3,262 MW (47 per cent) from hydropower plants, 120 MW (2 per cent) from coal power plants, 91 MW (1 per cent) from diesel power plants and 40 MW (less than 1 per cent) from solar power plants (Figure 1).[7] Other renewable energy sources (RES), such as biomass, geothermal power and wind power, are not significantly developed in the country and their installed capacity is negligible.

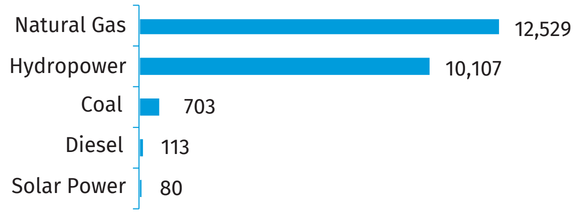
Total electric power generation in 2020 was 23,532 GWh.[8] Of this total, 12,529 GWh (53 per cent) came from natural gas power plants, 10,107 GWh (43 per cent) from hydropower plants, 703 GWh (3 per cent) from coal power plants, 113 GWh (less than 1 per cent) from diesel power plants and 80 GWh (less than 1 per cent) from solar power plants (Figure 2).[8] Generation has increased dramatically in recent years due to the commissioning of new natural gas power plants, which now form the largest single source of generation in the country, in addition to some growth of generation from solar power.

Figure 1. **Installed Electricity Capacity by Source in Myanmar in 2020 (MW)**



Source: MOEE[7]

Figure 2. **Annual Electricity Generation by Source in Myanmar in 2020 (GWh)**



Source: MOEE[8]

In recent years, Myanmar has experienced accelerated development of generation capacities from RES. The first solar power plant in the country (40 MW) became operational in June 2019. An additional 29 solar power plants with an installed capacity of 1,030 MW had been planned for construction by 2021, however, implementation of these projects has been delayed by political instability. Solar power was expected to provide 14 per cent of the country's generation mix by 2022, but has fallen short of this target.[9]

The nationwide electrification rate in Myanmar increased from 34 per cent in 2016 to 56 per cent in 2020. Earlier plans provided for 100 per cent electrification in the Yangon region and 75 per cent in the Mandalay region by 2021, but it is unclear whether these targets have been met.[9] In order to achieve universal electricity access by 2030, it is estimated that the installed generation capacity must double compared to 2020.[10]

The Government has implemented several policy and institutional reforms in the electricity sector since 2013. These include the adoption of the National Energy Policy in 2013, the National Electrification Plan in 2014, the National Electricity Master Plan in 2017 and the preparation of rules and regulations for off-grid electrification. The National Electrification Plan aimed to achieve a national electrification rate of 75 per cent by 2025 and 100 per cent by 2030, respectively. As a part of the National Electrification Plan, the Government launched the Myanmar National Electrification Project in 2015 with funding from the World Bank, aiming to guarantee universal electricity access through the establishment of a nationwide distribution grid.[10] The project was still ongoing as of 2022.

Additionally, in 2018 the Government of Myanmar launched the Myanmar Sustainable Development Plan 2018–2030 (MSDP), which prioritized reliable and affordable electricity to support economic development and poverty reduction, and universal electricity access by 2030. In order to reach these goals, the Government has focused on the development of power generation, transmission and distribution and on advanced policy and institutional reforms to improve the efficiency of investment in, and operation and management of, the energy sector. These reforms have included establishing a transparent mechanism for setting and implementing cost-reflective electricity tariffs, developing a public-private partnership (PPP) mechanism to mobilize private investment and corporatizing electricity supply entities to increase efficiency. Development partners in implementing these reforms, policies and projects have included the World Bank, the Asian Development Bank, the Japan International Cooperation Agency, the German Agency for International Cooperation (GIZ), the Department for International Development of the United Kingdom, the Italian Agency for Development Cooperation (AICS), KfW and the Governments of Norway and Australia.

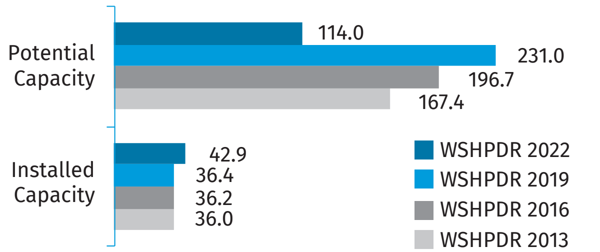
Electricity tariffs in Myanmar are low, compared to those of other ASEAN members. In 2019, the Government raised electricity tariffs for the first time in five years, with rates as much as tripling for residential consumers and nearly doubling for business consumers. Under the new tariff scheme, the rate for residential consumers remains at 35 MMK/kWh (0.02 USD/kWh) for usage up to 30 kWh, after which the price rises to as much as 125 MMK/kWh (0.09 USD/kWh). For business consumers, the rates rose to 125–180 MMK/kWh (0.09–0.12 USD/kWh) from 75–150 MMK/kWh (0.05–0.10 USD/kWh). The Government is subsidizing the cost of electricity, at an estimated cost of MMK 630 billion (USD 434 million) during the 2018–2019 financial year.[11]

SMALL HYDROPOWER SECTOR OVERVIEW

Myanmar has no official definition of small hydropower (SHP), although the definition of up to 10 MW is usually applied. Comprehensive information and statistics on SHP in Myanmar are difficult to acquire, as there is no dedicated government department or institution focused on SHP. Key players involved in SHP development in Myanmar include the Department of Hydropower Implementation at the Ministry of Electricity and Energy (MOEE), the Department of Rural Development and the Department of Irrigation and Water Utilization at the Ministry of Agriculture, Livestock and Irrigation and the Department of Research and Innovation at the Ministry of Science and Technology as well as the private sector organizations: Small Hydropower Association of Myanmar (SHPAM) and Renewable Energy Association of Myanmar (REAM).

As of 2021, there were a total of 36 SHP plants up to 10 MW included in the MOEE SHP database, with a total installed capacity of 38.67 MW. In addition, there were over 300 SHP plants overseen by other ministries with an estimated capacity of 4.2 MW. There are also over 2,000 privately owned SHP plants with capacities ranging from 10 kW to 3 MW in operation in the northern and north-western regions of the country (Kachin, Shan and Chin states), but their total installed capacity is not known.[12,13] The verifiable total SHP installed capacity in Myanmar thus amounted to 42.87 MW in 2021. Additionally, 119 potential SHP sites have been identified across the country with a total undeveloped potential capacity of 71.17 MW, bringing the total potential SHP capacity of Myanmar to 114.04 MW.[12] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed SHP capacity has increased by nearly 18 per cent due to the construction of new SHP plants (Figure 3). Meanwhile, potential SHP capacity has decreased by nearly 51 per cent as a consequence of revised MOEE data that substantially reduced both the number and total capacity of potential SHP sites listed in the MOEE database.[14] Table 1 summarizes the total installed and potential SHP capacities by region. A partial list of existing SHP plants in Myanmar is displayed in Table 2.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Myanmar (MW)**



Source: MOEE,[12] REAM,[13] *WSHPDR 2019*,[14] *WSHPDR 2013*,[15] *WSHPDR 2016*[16]

Table 1. **Operational and Potential Small Hydropower Projects by Region in Myanmar**

State/ Region	*Operational*		*Planned/Potential*		*Total*	
	Number of SHPPs	*Capacity (MW)*	*Number of SHPPs*	*Capacity (MW)*	*Number of SHPPs*	*Capacity (MW)*
Kachin	4	9.66	17	24.47	21	34.13
Kayah	1	0.12	2	0.22	3	0.34
Kayin	1	0.06	5	0.62	6	0.68
Chin	8	3.91	25	14.77	33	18.68
Mon	1	0.19	-	-	1	0.19
Rakhine	-	-	4	0.29	4	0.29
Shan	11	15.23	6	8.58	17	23.81
Sagaing	5	2.61	17	21.34	22	23.95
Tanintharyi	2	0.44	5	0.60	7	1.04
Bago	1	2.00	-	-	1	2.00
Mandalay	2	4.45	2	0.31	4	4.76
Total	**36**	**38.67**	**83**	**71.17**	**119**	**109.84**

Source: MOEE[12]

Note: Does not include 4.2 MW of SHP plants overseen by ministries other than MOEE.

Table 2. **List of Selected Existing Small Hydropower Plants in Myanmar**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Operator*	*Launch year*
Ahtet Nant Htwan	Putao, Kachin State	3.20	40.6	MOEE	2018
Tine Khan	Nan Yoon, Sagaing Region	1.00	28.0	MOEE	2018
Kya Lwe	La Hae, Sagaing Region	0.15	100.0	MOEE	2015
Ma Tu Gi	Lae Shee, Sagaing Region	0.15	44.0	MOEE	2015
Don Var	Haka, Chin State	0.60	64.0	MOEE	2014
Pa Kyet Haw	Chin Shwe Haw, Shan State	0.30	4.3	MOEE	2014
Nga Sit Var	Phalan, Chin State	1.50	121.9	MOEE	2013
Chi Chaung	Mindat, Chin State	0.16	12.8	MOEE	2011
Pa Thi	Taungoo, Bago Region	2.00	18.0	MOEE	2008
Nant Hou Mon	Kaung Khar, Shan State	0.15	37.5	MOEE	2005
Htwee Saung	Tonzaung, Chin State	0.20	39.6	MOEE	1998
Nan Khan Kha	Moe Kaung, Kachin State	5.00	128.0	MOEE	1996
Nant Saung Ngoung	Kyauk Mei, Shan State	4.00	148.0	MOEE	1996
Zee Chaung	Kalay, Sagaing Region	1.20	41.0	MOEE	1996
Nant Hmyaw	Lashio, Shan State	4.00	30.5	MOEE	1996
Ga Hlaing Chaung	Ho Pin, Kachin State	1.20	190.5	MOEE	1991
Mogoak	Mogoak, Mandalay Region	4.00	118.2	MOEE	1989
Hway Ka Pu	Phar Saung, Kayah State	0.12	61	MOEE	1988
Zar Lwee	Tedim, Chin State	0.40	141.7	MOEE	1984
Zin Kyaik	Paung, Mon State	0.19	109.3	MOEE	1984

Source: MOEE[12]

There were a number of planned SHP projects in Myanmar as of 2021, most in the early stages of planning. In addition, there are potentially hundreds of SHP sites that could be developed across the country, depending on the availability of a stream nearby and community needs. However, only a fraction of these sites has been properly identified and assessed. Table 3 provides a list of some planned SHP projects, while Table 4 lists several potential SHP sites.

Table 3. **List of Selected Ongoing Small Hydropower Projects in Myanmar**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Developer*	*Development stage*
Hwuay Htike	La Hal, Sagaing Region	3.00	27	MOEE	Feasibility study in 2019
Phon In Kha	Sumprabum, Kachin State	1.70	18	MOEE	Feasibility study in 2020
Laung Maw	Sault Law, Kachin State	1.20	62	MOEE	Feasibility study in 2020
Kerlay	Kyi Khar, Chin State	0.55	54	MOEE	Feasibility study in 2014
Nant Nan	Mat Mum, Shan State	0.40	58	MOEE	Feasibility study in 2018

Source: MOEE[12]

Table 4. **List of Selected Potential Small Hydropower Sites in Myanmar**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/refurbishment)*
Tanine Kha	Tanine, Kachin State	2.30	10	New
Phon Kyan Kha	Sumprabum, Kachin State	1.60	10	New
Phon In Kha	Sumprabum, Kachin State	0.90	10	New
Ti Del	HtanTaLan, Chin State	0.80	67	New
Thapyay Kha	Tanine, Kachin State	0.75	10	New

Source: MOEE[12]

In general, the development of SHP in Myanmar is hobbled by the lack of a targeted policy and legislation, despite the abundant SHP potential. Existing laws, such as the 2014 Myanmar Electricity Law, provide neither a regulatory framework nor incentives that apply to SHP specifically. The elaboration and adoption of these instruments is crucial for the future of SHP development in Myanmar.

RENEWABLE ENERGY POLICY

Myanmar is experiencing significant adverse impacts from climate change. Between 2019 and 2020, it was ranked as the world's second most affected country.[4] To provide a roadmap and to strategically address climate-related risks, the Government of Myanmar formulated and adopted the Myanmar Climate Change Policy (MCCP) and the related Myanmar Climate Change Strategy (MCCS) (2018–2030) in 2019.

The MCCP includes recommendations prioritizing and promoting RES and energy efficiency with the aim of meeting the growing energy needs of the country and ensuring energy security through low-carbon technologies.[6] The MCCS sets general goals for energy security and the sourcing of a significant share of total generation from RES. Overall, however, there is no comprehensive policy for RES development in Myanmar and specific targets for RES remain at the level of internal ministry reports not available to the public.[9] A comprehensive and binding set of RES policy initiatives and targets is still under development.

BARRIERS AND ENABLERS FOR SHP DEVELOPMENT

Myanmar has abundant water resources and high potential for SHP development. In view of the limited access to electricity still prevalent in rural areas, SHP should be one of the major RES serving rural communities. However, the development of the SHP sector in Myanmar is lagging.

Barriers to SHP development in the country include:

- Lack of legislation and regulations specifically targeting SHP;
- Limited financial resources and lack of green funding schemes in the banking system;
- Difficulty in developing community-based business schemes due to the low income levels in rural areas;
- Long and complicated procedures to acquire endorsement and approval for development from the authorities, including state and regional governments;
- Limited local technical knowledge, skills and operational experience in SHP;
- Insufficient technical data on topography, annual rainfall, distribution of water resources and potential SHP sites;
- Unstable political and economic situation in the country.

Enablers for SHP development in Myanmar include:

- Abundant water resources;
- SHP is particularly suitable to address significant unmet demand for electricity in rural areas;
- Government policies recommending development of SHP and RES in general.

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Philippines

Joan Cecilia C. Casila, University of the Philippines Los Baños

KEY FACTS

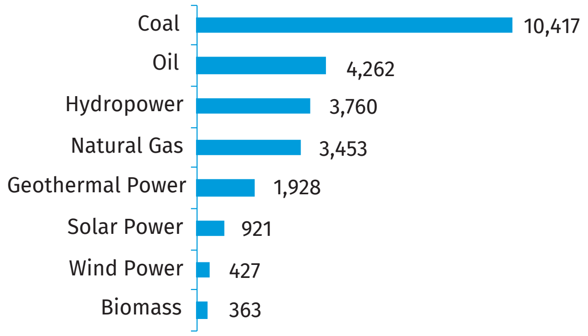
Population	109,581,085 (2020)[1]
Area	300,000 km[2]
Topography	The Philippines is an archipelagic country with more than 7,600 islands. It is divided into three major island groups: Luzon, Visayas and Mindanao. The highest point in the Philippines is Mount Apo with an elevation of 2,946 metres above mean sea level.[2] The larger islands (such as Luzon and Mindanao) are characterized by large volcanic peaks that emerge in the centre, with areas of low elevation around the shorelines.[3]
Climate	The climate of the Philippines is tropical and maritime. It is characterized by relatively high temperature, high humidity and abundant rainfall. The mean annual temperature is 26.6 °C.[4]
Climate Change	The observed temperature in the Philippines is warming at an average rate of 0.1 °C per decade. It is projected that the country-averaged mean temperature could increase by as much as 0.9–1.9 °C (assuming the moderate-emissions scenario, RCP4.5) or 1.2–2.3 °C (assuming the high-emissions scenario, RCP8.5) between 2036 and 2065. Warmer conditions or increase in mean temperature relative to the baseline climate are further expected by 2070–2099, ranging from 1.3–2.5 °C (RCP4.5) to 2.5–4.1 °C (RCP8.5).[4]
Rain Pattern	Rainfall distribution throughout the country varies from one region to another. The classification of climate per region is based on monthly rainfall received during the year using the Corona climate types (types I to IV). The mean annual rainfall of the Philippines varies from 965 mm to 4,064 mm annually.[5] The north-eastern monsoon (Amihan), characterized by cold winds, brings rains over the eastern side of the country from November to April. The south-western monsoon (Habagat), associated with heavy rain with warm moist winds, occurs from May to October.[6] The peak of the typhoon season is from July through October, when nearly 70 per cent of all typhoons develop.[7]
Hydrology	The Philippines is naturally endowed with major river basins, lakes, coastal and marine waters and groundwaters. There are 18 major river basins and 421 principal rivers defined by the National Water Resources Board (NWRB). The area occupied by the river basins is 108,923 km^2, which accounts for one third of the total land area. The largest river basin is Cagayan with a catchment area of 25,649 km^2. It is utilized for hydropower generation with several dams or powerplants built within its proximity. The second largest river basin is in Mindanao, covering an area of 23,169 km^2. There are 79 lakes that are mostly used for fish production. Laguna de Bay is the largest among the lakes with a total area of 900 km^2. It is also one of the five largest lakes in South-Eastern Asia.[8]

ELECTRICITY SECTOR OVERVIEW

In 2019, the Philippines had a total of 25,531 MW of installed capacity.[9] The major contributing electricity source was coal at 10,417 MW, or almost 40.8 per cent of the total installed capacity. Oil and natural gas contributed 4,262 MW or almost 17 per cent and 3,453 MW or almost 14 per cent, respectively. For the renewable energy sources, which accounted for a combined 7,399 MW, or 29 per cent of the total, hydropower contributed the highest at 3,760 MW or almost 15 per cent followed by geothermal power at 1,928 MW, or less than 8 per cent, solar power at 921 MW, or less than 4 per cent, wind power at 427 MW, or less than 2 per cent, and biomass at 363 MW, or 1 per cent (Figure 1).[9] From 2018, the installed capacity grew by approximately 7 per cent. A total of 1,675 MW of new capacity was added to the country's supply in 2019, including new coal-fired (1,559 MW), oil-based (8 MW), hydropower (31 MW), biomass (52 MW) and solar (25 MW) power plants.[9]

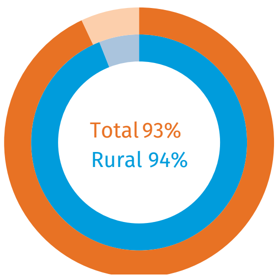
The power transmission in the Philippines is composed of three grids: the Luzon, Visayas and Mindanao grids. The total power peak demand in 2019 was 15,581 MW, which was 799 MW or 5 per cent higher than the 14,782 MW in 2018. The Luzon grid contributed 11,344 MW, or 73 per cent, of the total demand, while Visayas and Mindanao contributed a share of 14 per cent (2,224 MW) and 13 per cent (2,013 MW), respectively.[9] At the end of 2019, the electrification level reached 23.2 million households or 93 per cent of the total potential households.[10] From the World Bank Data, the access to electricity of urban and rural population in 2019 was 98 per cent and 94 per cent, respectively (Figure 2).[11]

Figure 1. **Installed Electricity Capacity by Source in the Philippines in 2019 (MW)**



Source: Department of Energy[9]

Figure 2. **Electrification Rate in the Philippines in 2019 (%)**

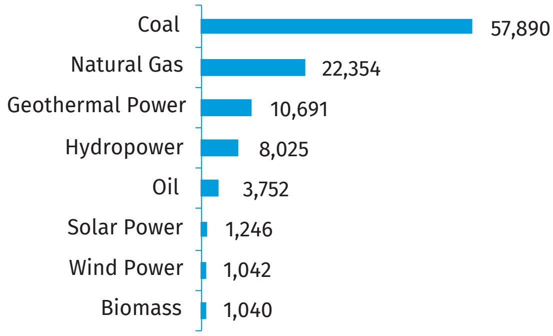


Source: Capongcol,[10] World Bank[11]

The electricity gross generation of 106,040 GWh in 2019 grew by 6 per cent from 99,765 GWh in 2018.[12] Coal dominated the power mix at 57,890 GWh, increasing its share from 52 per cent in 2018 to almost 55 per cent in 2019. Natural gas contributed 21 per cent (22,354 GWh), while oil-based plants contributed less than 4 per cent (3,752 GWh).[9] Fossil fuels dominated the mix, and renewable energy technologies decreased their total generation share to less than 21 per cent (22,044 GWh) due to continuous drop in generation from hydropower and limited penetration of other technologies into the mix. Geothermal power contributed 10 per cent (10,691 GWh), followed by hydropower at 8 per cent (8,025 GWh), solar power at 1 per cent (1,246 GWh), wind power at 1 per cent (1,042 GWh) and biomass at 1 per cent (1,040 GWh) (Figure 3).[12]

The Philippines is highly dependent on fossil fuels, which accounted for 67 per cent of total primary energy supply (TPES) in 2019.[13] Oil maintained its position as the country's major energy source with close to one third at 32 per cent of the TPES (31 per cent net imported oil and 1 per cent indigenous oil), while coal contributed 29 per cent.[13] The increase in coal-based generation was attributed to new coal-fired power plants across the country. The Government declared a moratorium on new coal power plants in 2020. Additionally, to boost private investment in renewable energy, the Government opened up the sector to full foreign ownership in geothermal power and hydropower, which included 17 potential hydropower projects (mostly small-scale) with a combined capacity of 80 MW.[14] The 17 Pre-Determined Areas (PDA) for hydropower were offered in the 3rd Open and Competitive Selection Process for Geothermal and Hydropower Resources. As of May 2021, no applications had been received for 9 PDAs, while applications for 8 small hydropower (SHP) PDAs were disqualified. The Open and Competitive Selection Process was declared a failure and the PDAs are now open for direct applications.[15]

Figure 3. **Annual Electricity Generation by Source in the Philippines in 2019 (GWh)**



Source: HOEMD, REMB & DOE[12]

Amidst the ongoing economic crisis and the high cost of household utilities, the Philippines has the second highest electricity cost in South-Eastern Asia. Unlike other neighbouring countries, such as Thailand, Indonesia and Malaysia, electricity rates in the Philippines are not subsidized by the Government.[16] In 2020, the overall average retail rate of electricity decreased by 10 per cent to 7.96 PHP/kWh (0.15 USD/kWh) from an 8.87 PHP/kWh (0.17 USD/kWh) average rate in 2019.[17]

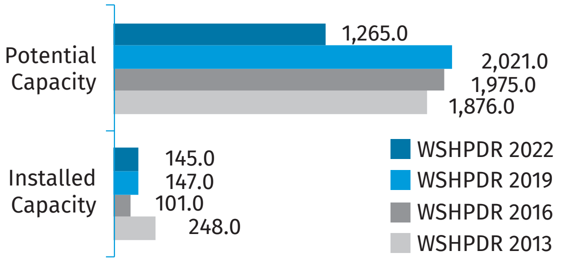
SMALL HYDROPOWER SECTOR OVERVIEW

In the Philippines, SHP is often a preferable choice to large hydropower due to the latter's negative environmental impacts, and SHP is considered one of the most cost-effective energy sources for rural electrification. SHP plants are economically more competitive and more sustainable than small-scale fossil fuel plants.[18] The country ranked 13th in the Eastern Asia and Pacific region for water resource availability.[14]

The term mini-hydropower is used in the Philippines for hydropower plants with 101 kW to 10 MW of installed capacity, while micro-hydropower defines plants with 1–100 kW capacity.[19] For this chapter, the term SHP will be used for hydropower plants of up to 10 MW. The Republic Act No. 7156, or the Mini-Hydro Law, was enacted to grant incentives to SHP developers.[20] The Law includes special privilege tax rates, tax and duty-free importation of machinery, equipment and materials.

As of December 2020, the Philippines had a total of 145 MW of installed SHP capacity and potential capacity of approximately 1,265 MW.[21] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, both installed and potential capacities decreased mainly due to terminated projects being removed from the list of active hydropower service contracts (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in the Philippines (MW)**



Source: DOE,[21] *WSHPDR 2013*,[22] *WSHPDR 2016*,[23] *WSHPDR 2019*[24]

Table 1 shows the most recently commissioned operational SHP plants, while Table 2 shows the ongoing SHP projects as of 2021.

Table 1. **List of Selected Operational Small Hydropower Plants in the Philippines**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Calibato	San Pablo, Laguna	0.3	Run-of-river	PHILPODECO	2020
Asiga	Santiago, Agusan del Norte	8.0	Run-of-river	Asiga Green Energy Corporation	2019
Catuiran	Naujan, Oriental Mindoro	8.0	Run-of-river	Catuiran Hydropower Corporation	2019
Majayjay	Majayjay, Laguna	2.2	Run-of-river	Majayjay Hydropower Company, Inc.	2019
Loboc 2	Loboc, Bohol	1.2	Run-of-river	Sta. Clara Power Corporation	2019
New Bataan	New Bataan, Compostela Valley	3.2	Run-of-river	Euro Hydro Power (Asia) Holdings, Inc.	2018
Palakpakin	San Pablo, Laguna	1.5	Run-of-river	PHILPODECO	2018
Balugbog	Nagcarlan, Laguna	1.1	Run-of-river	PHILPODECO	2018
Maris Main Canal 1	Ramon, Isabela	8.5	Run-of-river	SN Aboitiz Power – Magat, Inc.	2017
Villasiga	Bugasong, Antique	8.0	Run-of-river	Sunwest Water & Electric Company, Inc. 2	2016
PRISMC	Rizal, Nueva Ecija	1.0	Run-of-river	PNOC – Renewables Corporation	2016
Bulanao	Tabuk, Kalinga	1.0	Run-of-river	DPJ Engineers and Consultants	2016
Amlan	Dumaguete, Negros Oriental	0.8	Run-of-river	Amlan Hydroelectric Power Corporation	2016
Linao – Cawayan (Upper Cascade)	San Teodoro, Oriental Mindoro	3.0	Run-of-river	Oriental Mindoro Electric Cooperative, Inc.	2015
Likud	Asipulo, Ifugao	0.8	Run-of-river	Provincial Government of Ifugao	2015
Tudaya 2	Sta. Cruz, Davao del Sur	8.1	Run-of-river	HEDCOR Tudaya, Inc.	2014
Tudaya 1	Sta. Cruz, Davao del Sur	6.6	Run-of-river	HEDCOR Sibulan, Inc.	2014
Cabulig	Claveria, Misamis Oriental	8.0	Run-of-river	Mindanao Energy Systems, Inc.	, 2012
Irisan 1	Tuba, Benguet	3.8	Run-of-river	HEDCOR, Inc.	2012

Source: HOEMD, REMB & DOE[25]

A total of 17 potential (mostly small-scale) hydropower projects was offered to qualified renewable energy developers in 2021. The 3rd Open and Competitive Selection Process (OCSP3) was started to further accelerate the development of renewable energy in the country. Although initial uptake by developers was slow, these projects have sufficient available technical data to serve as initial reference for those who are interested in acquiring the rights to develop the hydropower resources.[26]

Several hydropower plants in operation in the country were registered under the Republic Act 9513 through Hydropower Service Contracts. The continued effort of the Government to provide electricity to marginalized areas has resulted in a number of new projects, one of which is the Likud mini-hydropower plant in Ifugao providing up to 820 kW of electricity to the grid. The electricity generated by the plant was intended for the purpose of rehabilitation of the rice terraces in Banaue. Another project is the 40 kW off-grid hydropower plant in the Municipality of Brooke's Point in Palawan. It supplies electricity to the Sitio Tagpinasao Elementary School, 25 households in the upland areas, with plans to increase service to up to 150 households.[27]

Table 2. **List of Selected Planned Small Hydropower Projects in the Philippines**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Developer*	*Planned launch year*
Alamada	Alamada, North Cotabato	3	Run-of-river	Euro Hydro Power (Asia) Holdings, Inc.	Q3 2021
Sipangpang	Cantilan, Surigao del Sur	1.8	Run-of-river	Paragon Pegasus Solutions, Inc.	Q3 2021
Tubig	Taft, Eastern Samar and Hilabangan, Samar	16	Run-of-river	Taft Hydroenergy Corporation	Q3 2021
Matuno	Bambang, Nueva Vizcaya	8.661	Run-of-river	Matuno River Development Corporation	Q3 2021
Labayat River (Upper Cascade)	Mauban, Quezon	1.4	Run-of-river	Labayat 1 Hydropower Corporation	Q3 2021

Source: HOEMD, REMB & DOE[25]

RENEWABLE ENERGY POLICY

Renewable energy is abundant and ideal for meeting the energy needs in the Philippines. This is because it is more suitable to provide small islands with decentralized renewable electricity than with centralized fossil fuel-based generation, which would need substantial grid investments. The competitive advantage of decentralized, carbon-free and flexible renewable energy compared with centralized and polluting coal is clear under the national circumstances of the Philippines and would improve energy access in remote areas and isolated islands.[28]

The Republic Act 9513 of 2008, or the Renewable Energy (RE) Act, was passed and was the first of its kind in South-Eastern Asia. The renewable energy law focuses on accessible, affordable and environmentally sustainable energy sources, or the so-called BiGSHOW, which stands for biomass, geothermal power, solar power, hydropower, ocean and wind power.[29] It encourages consumers and businesses to choose renewable energy resources through different fiscal and non-fiscal incentives. It has designed the following five major policy mechanisms to create a more renewable energy-friendly environment: feed-in tariff (FIT) system, net-metering system, renewable portfolio standards (RPS), Green Energy Option Programme (GEOP) and renewable energy market (REM).

The Renewable Energy Act of 2008 implementing rules and regulations mandated the Energy Regulatory Commission (ERC) to formulate and promulgate the FIT system rules. A resolution adopting the FIT rules was enacted in 2010. This policy aims to offer guaranteed payments on a fixed rate per kWh to emerging renewable energy resources, excluding any generation for its own use. The FIT ranges from USD 0.1936/kWh to USD 0.1174/kWh. As of 2020, the FIT rates approved by ERC were as follows: hydropower at 5.87 PHP/kWh (0.11 USD/kWh), wind power at 7.40 PHP/kWh (0.14 USD/kWh), solar power at 8.69 PHP/kWh (0.16 USD/kWh) and biomass at 6.60 PHP/kWh (0.12 USD/kWh). A resolution was approved to have in 2018–2019 a FIT of 5.87 PHP/kWh (0.11 USD/kWh) for run-of-river hydropower and 6.19 PHP/kWh (0.12 USD/kWh) for biomass.

The Development for the Renewable Energy Applications Mainstreaming and Market Sustainability (DREAMS) project initially started from August 2020 up to May 2021 and later was extended until January 2023. The project aims to reduce greenhouse gas emissions through the promotion and facilitation of the commercialization of renewable energy markets through the removal of barriers to increase investments in renewable energy-based power generation projects. The DREAMS Project is assisting the Renewable Energy Management Bureau (REMB) in the preparation of the National Renewable Energy Programme (NREP) 2020–2040. The NREP 2011–2030 defined the renewable energy targets and strategies to achieve overall 35 per cent of renewable sources in the energy mix. New targets were created under the NREP 2020–2040 with approximately 34,000 MW of renewable energy capacity set to be developed by 2040. As of 2019, the share of renewable energy in the total primary energy mix was 33 per cent. Net imported oil maintained its position as the country's major energy source, which was close to one third, followed by coal. With reduction of net importation by 1 per cent from 2018, energy self-sufficiency in 2019 improved to 51 per cent.[13]

The Philippines committed, through its Nationally Determined Contribution (NDC), to reduce greenhouse gas emissions by 30 per cent below the business-as-usual (BAU) levels by 2040. The 2017–2040 Philippine Energy Plan (PEP) also highlights the promotion of a low-carbon future as one of its energy sector strategic directions. To achieve these goals, emissions from fossil fuel combustion need to decline rapidly.[30]

The Sustainable Energy Finance (SEF) Programme is both an investment and an advisory programme being implemented by the International Finance Corporation (IFC) in different regions around the world. The Philippines SEF Programme was launched in 2008, the first in the Association of Southeast Asian Nations (ASEAN) region. The programme works with private banks to encourage lending to energy efficiency and renewable energy projects. Support is provided through technical advisory services, which help build capacity to develop new business lines, as well as through the Risk Sharing Facility (RSF), where IFC covers 50 per cent of the loan losses in case of default. With RSF, client banks are more inclined to finance energy efficiency and renewable energy projects, which enhances their portfolio build-up. At present, the Philippines SEF Programme has three partner private banks: Bank of the Philippine Islands (BPI), Banco De Oro (BDO) and BPI Globe BanKO (BanKO), with BPI having access to the RSF. The Development Bank of the Philippines

(DBP) and the Philippine National Bank (PNB) also offer financing to renewable energy projects.

Furthermore, the Renewable Energy Asia Fund (REAF) II invests in SHP, wind power, geothermal power, solar power and biomass projects in Asian developing markets, with a primary focus on India, the Philippines and Indonesia. REAF makes equity investments in small-scale renewable energy projects including hydropower projects of between 5 MW and 100 MW.

For renewable energy or SHP investors, several recent enabling policies and laws have been enacted. First was Executive Order No. 30 creating the Energy Investment Coordinating Council in order to streamline the regulatory procedures affecting energy projects. Other laws include: Republic Act No. 11032 Ease of Doing Business Act of 2018, DC2019-10-0013 Omnibus Guidelines Governing the Award and Administration of Renewable Energy and the Registration of Renewable Energy Developers, and Republic Act No. 11234 Energy Virtual One-Stop Shop (EVOSS) Act with its Department Circular No. DC2019-05-0007 (Implementing Rules and Regulations).

COST OF SMALL HYDROPOWER DEVELOPMENT

According to the Energy Generation Technology Assumptions for the Philippines Competitive Renewable Energy Zones (CREZ) Process, capital cost of putting up an SHP plant with capacity of less than 50 MW is 143,218,927 PHP/MW (2,830,000 USD/MW). The fixed operations and maintenance cost is 4,299,048 PHP/MW/year (84,949 USD/MW/year), while the grid connection cost (substation tie-in, 69 kV, steel tower, single circuit line) is 77,834 PHP/km/MW (1,538 USD/km/MW).[31]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The Philippines is one of the most vulnerable countries to climate change, due to its high exposure to natural hazards, dependence on climate-sensitive natural resources and vast coastlines.[32] On average, 20 tropical cyclones enter the Philippines region every year and approximately 8–9 of them directly cross the country.[7] These numbers are the highest in the world and are expected to increase in frequency and severity due to climate change.[33] Other effects of the climate crisis on SHP development include extended periods of well below average rainfall triggered by El Niño events, leading to reduced hydropower generation. Changes in precipitation patterns and surface water discharges may adversely impact run-of-river hydropower plants.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The establishment of SHP in the Philippines is hampered by the following:

- There is social prejudice against building large dams thereby generalizing the same situation towards all hydropower technologies, which is due to the lack of understanding of renewable energy;
- There is a food or power (food versus fuel) dilemma for most hydropower resources;
- Hydropeaking is a challenge. Hydropeaking refers to changes in river flow due to the storage of water for hydropower use and disconnected water bodies formed by the construction of hydropower dams and run-of-river facilities built within the river system;
- Hydropower projects are mostly located in remote areas that have difficulty in road access, peace and order;
- Access to financing remains a massive problem, with only a few domestic banks currently supporting renewable energy projects in the country and recent years showing significant downturns in investments;
- Hydropower production is intermittent and is vulnerable to climate risks.[18,27,34]

Enablers of SHP include:

- Several enabling policies and laws have been enacted recently;
- A range of international funding opportunities is available;
- There is a vast source for hydropower in the Philippines, which remains untapped.[19,33]

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Thailand

Sangam Shrestha, Asian Institute of Technology; and Manish Shrestha, International Centre for Integrated Mountain Development

KEY FACTS

Population	69,799,978 (2020)[1]
Area	513,120 km[2]
Topography	Mountains cover most of northern Thailand and extend along the border with Myanmar down through the Kra Isthmus and the Malay Peninsula. The highest point is Doi Inthanon Mountain at 2,565 metres above sea level. The central area is characterized by lowlands dominated by the Chao Phraya River Basin.
Climate	The climate of Thailand can be classified into three seasons: hot season (March–May), rainy season (May–October) and cold season (November–February). The temperature ranges from 24 °C to 30 °C. A tropical monsoon, generally hot and humid, impacts the country most of the year.[2]
Climate Change	The average temperature is expected to increase by 2 °C by 2050 and approximately 4 °C by 2080.[3]
Rain Pattern	Average annual rainfall ranges from 1,020 mm in the north-east to 3,800 mm in the peninsula. Eighty per cent of the total annual rainfall occurs from May to October.[2]
Hydrology	Thailand is divided into 25 major river basins. Four major rivers that originate from the north are the Wang, Ping, Yom and Nan, which confluence to become the Chao Phraya River. Water from such rivers as the Chi, Mun and Songkhram drains to the Mekong River.[4]

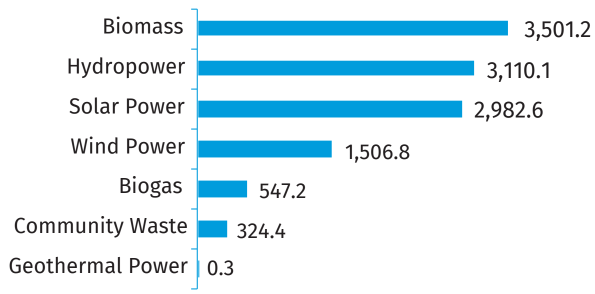
ELECTRICITY SECTOR OVERVIEW

The state enterprise Electricity Generation Authority of Thailand (EGAT) under the Ministry of Energy is the main authority responsible for the production and transmission of electric power throughout the country. As of November 2020, the total electricity generating capacity of Thailand was 39,760 MW, of which almost 40 per cent was from EGAT's power plants, whereas the remaining 60 per cent was from other domestic power plants including independent power producers (IPPs) and small power producers. An additional 5,721 MW was imported from neighbouring countries.[5] The total installed capacity of EGAT's power plants was 16,034 MW, including 8,262 MW from combined-cycle plants, 3,687 MW from thermal power plants, 3,055 MW from renewable energy plants, 30 MW from diesel-fired plants and 1,000 MW from other sources.[5]

As of September 2020, the total installed capacity of renewable energy was 11,972.6 MW, including 3,501.2 MW from biomass, 3,110.1 MW from hydropower, 2,982.6 from solar power, 1,506.8 MW from wind power, 547.2 MW from biogas, 324.4 MW from community waste and 0.3 MW from geothermal power (Figure 1).[6]

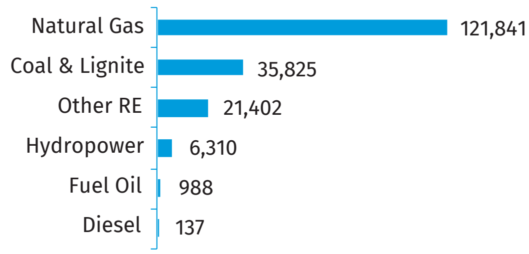
The major source of electricity generation in Thailand is natural gas followed by lignite. In 2019, Thailand generated 186,503 GWh of electricity and an additional 25,547 GWh was imported. Renewable energy sources, including hydropower, contributed 15 per cent of the total power produced in the country (Figure 2).[7]

Figure 1. **Installed Renewable Energy Capacity by Source in Thailand in 2020 (MW)**



Source: DEDE[6]

Figure 2. **Annual Electricity Generation by Source in Thailand in 2019 (GWh)**



Source: MoE[7]

EGAT has a total transformer capacity of 124,144 MVA with a total transmission length of 36,883 circuit-kilometres.[5] The electrification rate in the country is 100 per cent.[8]

EGAT has the sole right to buy electricity from private power producers and neighbouring countries. It sells wholesale electricity energy to two distributors: Metropolitan Electricity Authority (MEA), which supplies electricity to Bangkok, Nonthaburi and Samut Prakan, and Provincial Electricity Authority (PEA), which supplies electricity to the rest of the country.[9]

With the expansion of the economy and population growth, the electricity demand in Thailand has been going up every year. With the long-term economic growth projection of 3.8 per cent, net electricity demand is projected to increase by 3.13 per cent annually from 2018 to 2037.[10] It is forecasted that the peak energy demand in the year 2037 will be at 53,997 MW.[10] The Government plans to increase the total installed capacity to 77,211 MW by 2037, with a total of 56,431 MW of new capacity to be added and 25,310 MW of capacity to be retired during 2015–2037.[11] Further, it is planned that by 2037, approximately 37 per cent of the total power will be generated from renewable energy sources including hydropower.[12]

The Energy Regulatory Commission (ERC) is responsible for adjusting tariffs, which are uniform across the country in both the MEA and PEA distribution territories.[9] The electricity tariffs valid from November 2015 are shown in Table 1. The electricity tariff rate comprises two parts: a) a base tariff, which reflects the construction costs of power plants, the transmission and distribution costs, fuel and operation and maintenance costs; and b) automatic tariff adjustment (Ft) to compensate for inflation and exchange rate fluctuations at international fuel and power markets. Ft is adjusted every four months. In addition, a value-added tax (VAT) of 7 per cent is added to the base tariff and Ft.[9,13] The electricity tariff rate varies for different sectors based on an increasing block rate method. The tariff also varies according to the voltage level and time of consumption (peak and off-peak hours).[13]

Table 1. **Residential Electricity Tariff Rates in Thailand**

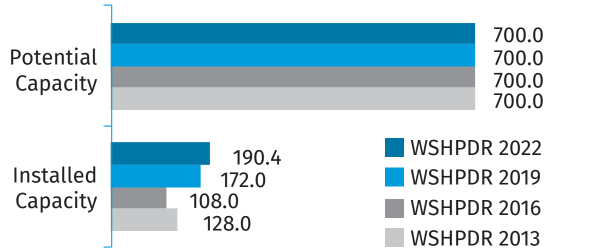
Normal tariff with consumption not exceeding 150 kWh/month	
Energy charge	*Rate per kWh*
First 15 kWh (1st – 15th)	THB 2.35 (USD 0.08)
Next 10 kWh (16th – 25th)	THB 2.99 (USD 0.10)
Next 10 kWh (26th – 35th)	THB 3.24 (USD 0.11)
Next 65 kWh (36th – 100th)	THB 3.62 (USD 0.12)
Next 50 kWh (101st – 150th)	THB 3.72 (USD 0.12)
Next 250 kWh (151st – 400th)	THB 4.22 (USD 0.14)
Over 400 kWh (up from 401st)	THB 4.42 (USD 0.15)
Service charge per month	TBH 8.19 (USD 0.27)

Source: MEA[13]

SMALL HYDROPOWER SECTOR OVERVIEW

Based on installed capacity, hydropower in Thailand can be classified as micro-hydropower (less than 200 kW), small/mini (200–6,000 kW), medium (6,000–20,000 kW) and large (above 20,000 kW).[14] The installed capacity of small hydropower (SHP) up to 6 MW in the country as of 2020 was 190.39 MW, indicating an 11 per cent increase compared with the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 3).[6] The development of SHP in the country is fostered through the national Alternative Energy Development Plan (AEDP2018), which set the goal of increasing the installed capacity of SHP to 376 MW by 2037.[15] The potential capacity of SHP is estimated at 700 MW.[16]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Thailand (MW)**



Source: DEDE,[6] MoE,[16] *WSHPDR 2013*,[17] *WSHPDR 2016*,[18] *WSHPDR 2019*[19]

Note: Data for SHP up to 6 MW.

Table 2 shows a list of some existing SHP plants in Thailand.

Table 2. **List of Selected Operational Small Hydropower Plants in Thailand**

Name	*Location*	*Capacity (MW)*	*Plant Type*	*Launch year*
Kiew Kho Ma Dam	Wang River, Lampang Province	5.5	Reservoir	2018
Khlong Tron Dam	Nam Pat District, Uttaradit Province	2.5	Reservoir	2018
Khun Dan Prakan Chon Dam	Nakhon Nayok	10.0	Reservoir	2005
Pa Sak Jolasid Dam	Pasak River, Lopburi Province	6.7	Reservoir	1999
Mae Ngat Somboon Chon Dam	Mae Ngat River, Chaing Mai province	9.0	Reservoir	1986
Ban Khun Klang	Ban Khun Klang Villaage, Choom Thong District, Chiang Mai Province	0.2	N/A	1982
Ban Santi	Ban Santi 1 Village, Bannang Sata District, Yala Province	1.3	N/A	1981
Huai Kum Dam	Nam Phrom River, Chaiyaphum province	1.1	Reservoir	1980

Name	*Location*	*Capacity (MW)*	*Plant Type*	*Launch year*
Ban Yang	Ban Yang, Fang District, Chiang Mai Province	0.1	N/A	1972
Nam Pung Dam	Phung River, Sakon Nakhon Province	6.0	Reservoir	1965
Naresuan Dam	Nan River, Phitsanulok Province	8.0	Reservoir	N/A
Huai Kui Mang	N/A	0.1	N/A	N/A
Klong Chong Klam	N/A	0.02	N/A	N/A

Source: EGAT[20]

Note: SHP plants up to 10 MW.

The northern part of Thailand has most of the potential for developing SHP. An additional 256 sites in the northern part of Thailand have been identified for the development of small and medium hydropower plants.[14]

RENEWABLE ENERGY POLICY

The Ministry of Energy (MoE) of Thailand, developed five integration master plans: 1) Thailand Power Development Plan (PDP2018), 2) Energy Efficiency Development Plan (EEDP), 3) Alternative Energy Development Plan (AEDP2018), 4) Natural Gas Supply Plan and 5) Petroleum Management Plan.

Thailand Power Development Plan 2018–2037 targets an additional 56,431 MW of installed capacity by 2037, of which 53 per cent will be powered by natural gas, 20 per cent by renewable energy, 12 per cent by coal, 9 per cent will come from import and 6 per cent from energy saving.[12] The Energy Efficiency Development Plan seeks to reduce greenhouse gas (GHG) emissions according to the pledge submitted to the United Nations Framework Convention on Climate Change (UNFCCC) at COP21. In particular, it set the target to reduce final energy consumption by 20 per cent in 2030 compared to 2005.[21] The Alternative Energy Development Plan aims to increase the share of renewable energy in the total power demand to 33 per cent in 2037.[15] The Alternative Energy Development Plan promotes renewable energy schemes designed to strengthen the community, lessen the dependence on fossil fuels and address social problems such as municipal solid waste (MSW) and agricultural waste. The development strategies to reach this goal include:

- Promotion of power generation from MSW (900 MW), biomass and biogas (6,714 MW), to benefit both farmers and communities;
- Set up targets for provincial renewable energy development by zoning electricity demand and renewable energy potential;
- Development of power generation from solar and wind power if the investment costs can compete with power generation using liquefied natural gas (LNG);
- Provision of incentives by using competitive bidding and promotion of energy consumption reduction.

The government policy supports the participation of the private sector in electricity generation. Small and Very Small Power Purchase Agreements (2002), Strategic Plan for Renewable Energy Development (2004), Feed-in Premium for Renewable Power (2009), National Renewable Energies Development Plan 2008–2022 (2012), Alternative Energy Development Plan: AEDP (2018) and Thailand Power Development Plan 2018–2037 (PDP2018) are some of the policies supporting private investment in the energy sector.

To promote and support alternative energy, MoE provides feed-in tariffs (FITs) to very small power producers.[11] The FITs are provided for a 20-year term to all forms of renewable energy except for landfill, which is eligible for a period of 10 years. For some projects, FITs will provide financial certainty over a period twice as long as under the adder rate scheme. The rates are determined based on the type of renewable energy, installation location and installed capacity. The highest rates are provided to MSW and wind energy. For hydropower projects, the FIT rate is 4.9 THB/kWh (0.16 USD/kWh) for 20 years.[11] Projects located in Yala, Pattani, Narathiwat and four subdistricts of Songkla (Jana, Tepha, Sabayoi and Natawee) will receive 0.50 THB/kWh (0.02 USD/kWh) for the lifetime of the project.[16]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Construction of SHP plants is restricted in protected areas. The relevant regulations include:

- Forest Act (1941);
- National Park Act (1955);
- National Reservation and Protection Act (1992);
- National Reserved Forest Act (1964);
- Cabinet Resolution of 15 May 1990 restricting the use of conservation areas by private agencies.

BARRIERS AND ENBLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main obstacles to SHP development in Thailand are presented by the following factors:

- Most of the potential hydropower sites in the northern region of Thailand are located in protected forested areas;
- The existing policies undermine the growth of the SHP sector. If the policies were reformed with the provision of the right of ownership and selling of excess electricity, this would attract private investors and contribute to the development of SHP as well as the national grid.[22,23]

The key enabling factors for SHP development include:

- Political will and support for renewable energy development and SHP specifically;
- Availability of incentives for renewable energy producers.

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24.

Timor-Leste

Danila Podobed, International Centre on Small Hydro Power (ICSHP)

KEY FACTS

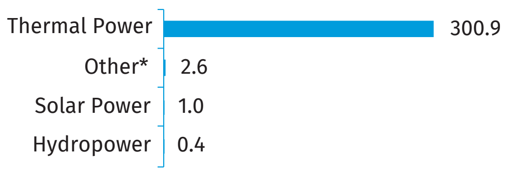
Population	1,280,743 (est. 2019)[1]
Area	14,954 km^2 [1]
Topography	The topography of Timor-Leste is primarily mountainous. The interior of the country is dominated by the Ramelau Range, with the country's highest point located at Mount Ramelau, 2,986 metres above sea level. In the north of the country the mountains extend almost directly to the coast, but in the south the elevation decreases and levels off, forming a coastal plain.[2,3]
Climate	Timor-Leste is divided into three climactic regions. The northern coast region is characterized by mean annual temperatures of over 24 °C, moderate rainfall and a dry season lasting five months. In the mountainous region, average annual temperatures are below 24 °C, rainfall is high and the dry season lasts four months. In the southern coast region, average annual temperatures are above 24 °C, rainfall is very high and the dry season lasts only three months.[3]
Climate Change	Observations indicate that average temperatures in Timor-Leste have been increasing by approximately 0.16 °C per decade since 1950. Climate change projections for Timor-Leste predict a rise in average annual temperatures of between 1.25 °C and 1.75 °C by 2050.[3]
Rain Pattern	Average annual precipitation in Timor-Leste ranges from less than 1,000 mm in lowland areas of the northern Coast to approximately 2,500 mm on the mountain slopes facing the South Coast, where rain falls for nine months out of the year.[3]
Hydrology	There are more than 100 rivers in Timor-Leste, but very few of these flow year-round. The longest river, the Northern Laclo, is 80 kilometres long. Lake Ira Lalaro is considered the largest lake in the country, with the lake's area fluctuating anywhere between 10 and 55 km^2.[2,3]

ELECTRICITY SECTOR OVERVIEW

The electricity sector of Timor-Leste is almost entirely dependent on thermal power. In 2021, the total installed electricity generating capacity in the country was approximately 304.9 MW, including 300.9 MW (99 per cent) provided by utility-scale thermal power plants, an estimated 1.0 MW provided by distributed solar power and nearly 0.4 MW provided by hydropower, in addition to 2.6 MW provided by a mix of solar power and diesel generators on Atauro Island (Figure 1).[4,5,6] There are four major thermal power plants in the country, although with the 27.5 MW Comoro power plant out of operation, the available thermal power capacity amounts to 273.4 MW (Table 1).[5] Solar power in the country is represented by a large number of small- and medium-sized installations with an estimated 1 MW total installed capacity, including a 300 kW solar power plant installed at the United Nations House in Dili.[6,7] Additionally, a number of generators powered by biogas have been installed across Timor-Leste, but accurate data on their cumulative installed capacity are not available.

Electricity generation in the country was estimated at 604 GWh in 2019, including approximately 602 GWh (nearly 100 per cent) provided by thermal power, 2 GWh provided by hydropower and 1 GWh provided by solar power (Figure 2).[6] Current electricity generation is sufficient to meet current and projected demand and no additional capacities will be necessary until approximately 2030. Demand is expected to rise with the completion and gradual expansion of the Tibar Bay Port and other projects after 2022.[4,5] Peak load increased from 73 MW in 2019 to 90 MW in 2021. Technical losses amounted to approximately 35 per cent as of 2021, with approximately 15 per cent losses across the transmission network and another 20 per cent in the distribution network.[5]

Figure 1. **Installed Electricity Capacity by Source in Timor-Leste in 2021 (MW)**



Source: Secretary of State for Environment,[4] ADB,[5] IRENA[6]

Note: *Referring to the mixed power system on Atauro Island, the composition of which is unclear from available data.

Table 1. **Utility-Scale Thermal Power Plants in Timor-Leste in 2021**

Name	*Capacity (MW)*
Betano	136.6
Hera	119.5
Comoro*	27.5
Inur Sakata (Ocussi-Ambeno)	17.3
Total	**300.9**

Source: ADB[5]

Note: *Out of operation as of 2021.

Figure 2. **Annual Electricity Generation by Source in Timor-Leste in 2020 (GWh)**

Source: IRENA[6]

Nationwide electricity access in Timor-Leste was 96 per cent in 2020 and over 94 per cent in rural areas, while access of households to the national grid was estimated at 80 per cent.[5,8] The transmission network consists of 603.4 circuit kilometres of 150 kV lines, while distribution is carried out over 2,500 circuit kilometres of 20 kV lines. The national electricity grid has consolidated over the past decade, replacing a series of mini-grids that in 2011 included 58 small-scale diesel generators supplying approximately 40 MW.[9] The generators themselves have also been replaced by large-scale thermal power plants and most are no longer in operation. As of 2021, the national grid serviced over 200,000 consumers.[5]

Generation, transmission and distribution of electricity in Timor-Leste is carried out by Electricidade de Timor-Leste (EDTL), a vertically integrated power utility company that had previously operated as a department in the Ministry of Public Works before being transformed into a state-owned enterprise in January 2021. The National Authority for Electricity (NAE), also established in 2021, acts as the state regulator of the electricity sector. The Finnish company Wärtsilä has been contracted to operate the country's diesel-powered plants in 2012 and again in 2017, while the China Nuclear Industry 22nd Construction Co. has been awarded the management contract for the transmission network in 2015.[5]

The cost of electricity generation for EDTL is predicated on the high cost of fossil fuel imports and was 0.42 USD/kWh in 2021. However, electricity tariffs are subsidized by the Government for all consumer categories and connection types.[5] Electricity tariffs, current as of 2021, are displayed in Table 2. Additionally, approximately 60 per cent of the generated electricity is not billed due to technical losses as well as unmetered and illegal connections. Prepaid electricity meters have been installed in Dili but much of the countryside still relies on unmetered connections.[5]

Table 2. **Electricity Tariffs in Timor-Leste as of 2021**

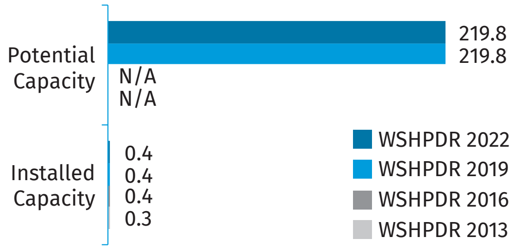
Category	*Monthly consumption*	*Price (USD/kWh)*
Residential (lifeline)	Up to 20 kWh	0.05
Residential	Over 20 kWh	0.12
Commercial	N/A	0.19
Industrial	N/A	0.24

Source: ADB[5]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Timor-Leste is 50 MW.[10] As of 2020, the installed SHP capacity in the country amounted to 0.35 MW, consisting of the 326 kW Gariuai (Gariwai) SHP plant, the 12–15 kW Loi-Huno SHP plant and the 15 kW Mausiga (Ainaro) SHP plant. However, all three plants were out of operation as of 2020 due to a variety of technical and environmental issues.[4,11] Potential for SHP up to 10 MW has been estimated at 219.8 MW in 2012.[12] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, both installed and potential capacity of SHP up to 10 MW have remained the same, due to lack of SHP development as well as updated studies on SHP potential (Figure 3).[10]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Timor-Leste (MW)**



Source: Secretary of State for Environment,[4] *WSHPDR 2019*,[10] Secretary of State for Energy Policy & Norwegian Water Resources and Energy Directorate,[12] *WSHPDR 2013*,[13] *WSHPDR 2016*[14]

A study of the country's hydropower potential was carried out between 2003 and 2006 by the Government of Timor-Leste in cooperation with the Norwegian Water Resources and Energy Directorate. The study identified 23 potential locations for SHP plants up to 10 MW with a total potential capacity of 219.8 MW and an estimated annual generation potential of 812.8 GWh. Of these, 15 sites with a total capacity of 187.6 MW and an estimated annual generation of 670.6 GWh were judged to be economically viable.[12] There are no official estimates of potential capacity for SHP up to 50 MW. However, a long-proposed hydropower project at Ira-lalaro Lake has been estimated as having a potential capacity ranging from 12 MW to 28 MW.[11,15] This suggests a total potential capacity, for SHP up to 50 MW, of at least 231.8–247.8 MW.

Overall, additional development and operation of SHP plants in Timor-Leste is complicated by the country's geological and environmental conditions. This includes a high mineral and sediment load of stream water interfering with turbines, as well as the porous nature of the bedrock that makes the impoundment of water necessary for the operation of reservoir-type plants difficult in certain locations.[4,15]

RENEWABLE ENERGY POLICY

Renewable energy development in Timor-Leste has been outlined in the Timor-Leste Strategic Development Plan 2011–2030, which was adopted in 2011 and targets a 50 per cent share of the country's energy needs to be sourced from renewable energy sources by 2030. The Plan estimates the country's total renewable energy potential from solar power, wind power, hydropower, biomass and solid waste to be 450 MW.[9]

Public consultations on a Draft Renewable Energy Law were carried out in 2016–2018 with the support of the United Nations Development Programme (UNDP). The Law is expected to target the creation of a financial mechanism for the promotion of renewable energy development and human capacity building in the sector.[5,10]

In 2017, Timor-Leste developed a National Climate Change Policy (NCCP), which promotes the gradual decarbonization of the electricity sector of the country through the promotion of renewable energy sources, particularly in rural areas. The Second National Communication of Timor-Leste under the United Nations Framework Convention on Climate Change (UNFCCC), published in 2020, projects a total annual electricity generation of 828.8 GWh by 2030. This is to include 128.2 GWh (15 per cent) provided by wind power, 89.7 GWh (11 per cent) provided by hydropower and 1.7 GWh (less than 1 per cent) to be provided by solar power. The remaining 609.1 GWh (73 per cent) are to be provided by thermal power, with generation from thermal power on a decreasing trend after 2028.[4]

Little progress on installing new renewable energy capacities has been made so far, although solar power biomass applications used for both electricity generation and other purposes have been gradually expanding their presence, particularly in rural areas.[4] A memorandum of understanding was signed by the Government and private companies in 2018, targeting the addition of 28 MW in solar power capacity, while the Ministry of Public Works launched the installation of 3,000 solar panels in remote parts of the country in 2020–2021.[16]

EFFECTS OF C4LIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Total annual precipitation is expected to increase in Timor-Leste in the coming decades, up to 100–120 mm in coastal areas and 260–300 mm in the mountains. However, the impact of this shift on local water resources is poorly understood, with expected decreases to potable water quality as a result of extreme weather events such as floods. The impact on river systems is also expected to be negative and include degradation of watersheds, erosion and landslides.[3] Although hydropower plays a negligible role in the electricity sector of Timor-Leste at the current stage, these factors may be expected to complicate further development of SHP and other hydropower due to increased competition with other water use sectors and potential damage to infrastructure.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key obstacles to SHP development in Timor-Leste include the following:

- Significant available reserve capacities of thermal power coupled with moderate energy demand obviate the need for additional capacity in the near term;
- Extension of the national grid removing the need for local generating capacity in many remote communities;
- Geological and environmental conditions complicating the construction and operation of SHP plants;
- Climate impacts negatively affecting available water sources.

Enablers for SHP development in the country include:

- Significant remaining SHP potential assessed and inventoried in previous studies;
- Demand for stable electricity access by the approximately 20 per cent of households not yet connected to the national grid;
- High cost of electricity generated from thermal power;
- Projected future growth in electricity demand;
- Ambitious government projections for generation from hydropower to 2030;
- Existing non-operational SHP plants that require refurbishment.

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Viet Nam

Danila Podobed, International Centre on Small Hydro Power (ICSHP)

KEY FACTS

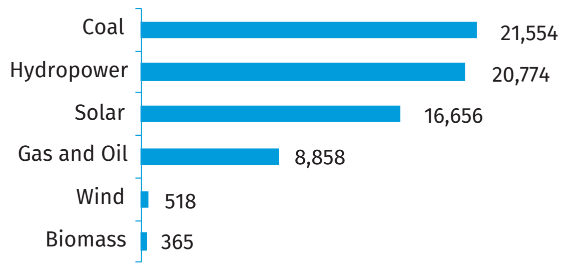
Population	97,338,583 (2020)[1]
Area	330,972 km^2 [2]
Topography	Viet Nam has five topographical regions. The north of the country consists of the Northern Highlands and the Red River Delta, while the south includes the Annamite Range, the Coastal Lowlands and the Mekong River Delta. Mountains comprise approximately 80 per cent of the area of Viet Nam, with the country's highest point at Mount Fansipan (3,143 metres).[3]
Climate	Viet Nam has a tropical monsoon climate throughout much of the territory, with differences between north and south. The northern climate has four distinct seasons, while the southern climate is composed of a wet season lasting from May to November and a dry season lasting from December to April. Average monthly temperatures range from 10–16 °C in the winter to 25–30 °C in the summer.[4] Average temperatures vary greatly. For example, in Hanoi they can range from 17 °C in January to 29°C in June.[4]
Climate Change	Average annual temperatures in Viet Nam experienced a gradual increase between 1958 and 2014 of 0.62 °C, rising at approximately 0.10 °C per decade. According to climate change projections, average annual temperatures in the country are expected to rise by 1.3–1.7 °C by the mid-21st century under a moderate climate change scenario and by 1.8–2.3 °C under an extreme climate change scenario.[4]
Rain Pattern	Most rainfall in Viet Nam occurs during the monsoon season, with the north and south receiving heavy rains from May to October and the central parts of the country from September to January. Average annual precipitation is 1,763 mm in Hanoi, 2,867 mm in Hue and 1,910 mm in Ho Chi Minh City. The average air humidity is over 80 per cent.[5]
Hydrology	The two major rivers in Viet Nam are the Red River in the north and the Mekong River in the south, with a length of 510 kilometres and 220 kilometres respectively. The overall length of all of the country's rivers is 41,000 kilometres, with approximately 300 billion m^3 of water flow per year, in addition to 3,100 kilometres of canals.[5]

ELECTRICITY SECTOR OVERVIEW

The major sources of electricity generation in Viet Nam are coal, natural gas and hydropower, with solar power capacity undergoing a dramatic expansion in recent years but providing relatively little electricity. Total installed electricity capacity in Viet Nam was 68,725 MW in 2020, of which coal-fired power plants provided 21,554 MW (31 per cent), hydropower provided 20,774 MW (30 per cent), solar power provided 16,656 MW (24 per cent), gas- and oil-fired power plants provided 8,858 MW (13 per cent), wind power provided 518 MW (1 per cent) and biomass provided 365 MW (1 per cent) (Figure 1). An additional 572 MW were available from interconnections with China and Laos.[6]

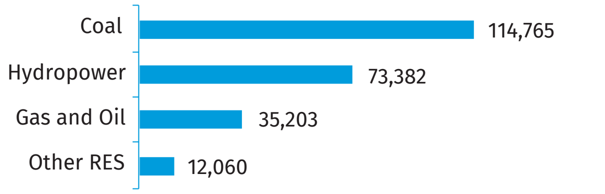
Total electricity generation in 2020 reached 235,410 GWh, with coal providing 114,765 GWh (49 per cent) of the total, hydropower providing 73,382 GWh (31 per cent), gas and oil providing 35,202 GWh (15 per cent) and non-hydropower renewable energy sources (RES) including solar power, wind power and biomass providing 12,060 GWh (5 per cent) (Figure 2). Electricity imports from China and Laos totalled 3,059 GWh.[6]

Figure 1. **Installed Electricity Capacity by Source in Viet Nam in 2020 (MW)**



Source: EVN[6]

Figure 2. **Annual Electricity Generation by Source in Viet Nam in 2020 (GWh)**



Source: EVN[6]

The energy mix of Viet Nam has been undergoing significant shifts over the last decade. Hydropower, once the mainstay of the electricity sector in the country, has seen its share of total installed capacity decrease from 46 per cent in 2014 to 43 per cent in 2016 and 36 per cent in 2019. The share of large hydropower plants is expected to decrease further to less than 18 per cent by 2030. Meanwhile, coal-fired power plants have expanded their share of installed capacity from 28 per cent in 2014 to 36 per cent in 2019, with the generation of electricity from coal nearly doubling between 2016 and 2020. At the same time, the share of coal as well as hydropower decreased between 2019 and 2020 due to a dramatic expansion of solar power capacity, from just 9 per cent of total installed capacity in 2019 to 24 per cent in 2020. This expansion was largely driven by rooftop solar power, which increased by a factor of 24 over the course of the year.[6,7,8,9]

The electricity sector development strategy of Viet Nam is outlined in the Power Development Plan (PDP). Under PDP 7 published in 2011 and revised in 2016, coal power was to continue expanding its share of both installed capacity and generation to reach 49 per cent and 55 per cent, respectively, by 2025.[9] However, the 2022 updates to the draft PDP 8, under continuous revision since 2021, have signalled a shift away from a major expansion of coal power in favour of RES in line with the commitments of Viet Nam towards decarbonization made at the 2021 United Nations Climate Change Conference (COP26).[10] Consequently, capacity targets for coal-fired thermal power have been revised downwards from 47,877 MW by 2025 and 55,477 MW by 2030 to 29,523 MW and 37,323 MW, respectively. At the same time, the targets for solar power and wind power have been increased by a factor of 3–4. Relative to PDP 7, hydropower targets have been revised slightly downwards.[11] Expansion of hydropower capacities in Viet Nam is difficult due to the saturation of the existing large hydropower potential, with no significant expansion of large hydropower planned after 2025. At the same time, substantial growth of the small hydropower (SHP) sector, along with that of other RES, is planned until at least 2045.[11,12]

The progress of Viet Nam in electrification has been outstanding, with 100 per cent of the population having access to electricity as of 2020. In 1997, this rate stood at 78 per cent.[13] In the 2000s, the Government increased its support for rural electrification efforts, especially in remote communities and villages. As a result, the use of off-grid systems, including SHP plants, increased across the country and in rural areas in particular.[14]

The state remains the main actor in the electricity sector, with the state-owned Electricity Corporation of Viet Nam (EVN) owning approximately 17 per cent of the country's total installed capacity and three subsidiary generation companies (GENCOs) owning 25 per cent. The remaining 57 per cent are owned by foreign build-operate-transfer (BOT) companies and domestic independent power producers (IPPs).[6,8]

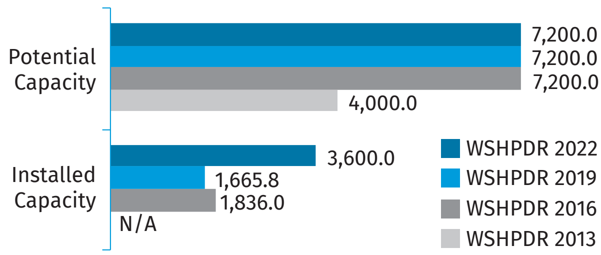
The country's electric system is operated at a high voltage of 110 kV, 220 kV and 500 kV and at a medium voltage of 6 kV to 35 kV, which is integrated into the 500 kV transmission network. The power transmission lines of 220 kV and 500 kV are managed by EVN's National Transmission Power Corporation (NTC), while the 6 kV, 35 kV and 110 kV lines are managed by regional power utilities.[6,15]

The Electricity Regulatory Authority of Viet Nam (ERAV) is responsible for monitoring and setting electricity tariffs in the country. In 2009, the Government embarked on tariff reforms aimed at establishing market-based retail tariffs with performance-based tariffs for transmission and distribution.[7] As of March 2019, the average retail electricity tariff in the country stood at 1,864.44 VND/kWh (0.083 USD/kWh), increasing from 1,568.70 VND/kWh (0.069 USD/kWh) in 2017. Electricity tariffs in Viet Nam are lower than average for the Association of Southeast Asian Nations (ASEAN) countries and globally, ranking 101 out of 147 countries in descending order.[7,16]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of SHP in Viet Nam is up to 30 MW (as per Decision of the Ministry of Industry No. 3454/QD-BCN dated 18 October 2005).[7] As of 2020, the installed capacity of SHP up to 30 MW was approximately 3,600 MW and SHP potential is estimated at 7,200 MW, indicating that 50 per cent of total potential has been developed so far.[8,11] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity has more than doubled due to ongoing SHP development, while estimated potential capacity has remained the same (Figure 3).[8]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Viet Nam (MW)**



Source: *WSHPDR 2019*,[8] Burke & Nguyen,[11] *WSHPDR 2013*,[17] *WSHPDR 2016*[18]

The development of SHP plants in Viet Nam is mainly concentrated in the northern and central parts of the country.

The first plants were constructed and funded by the Government between 1960 and 1985. Between 1985 and 1990, the hydropower sector received investments from other parties, including ministries, industries, provinces, military units and cooperatives. In 2003, the electricity market was liberalized and the private sector started investing as well.[8]

Between 2011 and 2014, the number of SHP plants in the country increased dramatically, owing to a high inflow of private investments. However, lax oversight, lack of expertise and violation of agreements on the part of some developers have resulted in floods, dam breaches, deforestation and environmental degradation. As a consequence, the Government ultimately decided to strengthen its oversight on licensing new plants, especially small-scale ones. The Government also started cancelling planned SHP projects, including those already under construction. In October 2013, for example, 418 projects with a total capacity of 1,174 MW were removed from the country's hydropower development plan.[19,20,21]

In 2016, after a three-year review conducted in collaboration with the province legislative officials, the Ministry of Industry and Trade (MOIT) decided to remove 471 small and cascade hydropower plants from its PDP 7, including 8 large hydropower projects with a total installed capacity of 655 MW and 463 SHP projects with a total installed capacity of 1,404 MW. MOIT also rejected another 213 potential projects because of environmental and efficiency concerns.[22]

RENEWABLE ENERGY POLICY

The development of RES in Viet Nam has increased in recent years, accelerating after the COP26 summit in 2021 and the country's commitment to carbon neutrality by 2050. The increasing dependence of Viet Nam on fossil fuels imports due to rapid growth in energy demands has also contributed to calls for diversifying the country's energy mix away from fossil fuels.[23]

In 2015, the Government adopted the Renewable Energy Development Strategy 2016–2030 with outlook until 2050, (REDS) which came into force in 2016. The REDS set clear medium- and long-term goals, in particular for biomass, wind power and solar power technologies. The goals included an increase in the share of renewable energy in the installed capacity of large generation companies to 10 per cent by 2030 and 20 per cent by 2050, as well as a reduction of greenhouse gas emissions by 45 per cent by 2050.[24] REDS targets were expanded by the 2016 amendments to PDP 7, which set targets to 2030 of 5,990 MW in wind power capacity, 11,765 MW in solar power capacity, 3,444 MW in total capacity of biomass and other RES and a total hydropower capacity of 27,871 MW. All RES are to contribute roughly 38 per cent of total installed capacity by 2030.[11]

In 2020, the Government of Viet Nam passed Resolution No.55, which radically expanded the role renewable energy was to play in the country's planned energy development. The Resolution represented a clear direction away from the expansion of coal power outlined in PDP 7 and informed the sectoral targets set by the draft PDP 8.[12] While PDP 8 was still undergoing revisions as of mid-2022, expected targets would have RES accounting for approximately 50 per cent of total installed capacity in the country by 2030, with the share of coal reduced to less than 10 per cent by 2045 and plans for the construction of a nuclear power plant halted indefinitely.[10,11,12,23] Under the draft PDP 8, SHP was expected to increase to 5,000 MW by 2030 and to 5,900 MW by 2045.[11] These renewable energy targets will also be reflected in the National Energy Master Plan for the Period 2021–2030, Vision 2050, being drafted in parallel with PDP 8.[12]

The main instrument for the promotion of renewable energy in Viet Nam is the standardized Special Power Purchase Agreement for plants up to 30 MW and a standard tariff for small generators. Feed-in tariffs (FITs) had previously been available for solar power, wind power, biomass and solid waste.[8] As of 2021, FITs ranged between 0.085 USD/kWh and 0.098 USD/kWh for wind power, with proposed rates reduced to 0.068–0.082 USD/kWh for projects commissioned after 2023, while for solar power FITs ranged between 0.071 USD/kWh and 0.094 USD/kWh.[25] Since 2017, FITs for solar power and wind power have been continually revised downwards and there are indications that Viet Nam is planning to phase out FITs altogether and fully replace them with auction schemes, with the first auctions for solar power commencing in 2021.[12,25]

SHP development in Viet Nam has been incentivized with an avoided-cost tariff (ACT), defined as the difference between the cost of generation from SHP and the cost of generation of an equivalent amount of electricity from thermal power and subject to seasonal fluctuations.[7,26] The ACT for SHP was approximately 0.050 USD/kWh in 2020.[27]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are several barriers to the development of SHP in Viet Nam, including:

- Lack of a strong institutional and regulatory framework, leading to legal violations and environmental and social risks;
- Poor quality of construction and safety control, with subsequent low return of investment;
- Poor quality of management leading to concerns over efficiency;
- Repeated revisions to development plans leading to significant reductions in the number of planned SHP projects.

Enablers for SHP development in the country include the following:

- Considerable remaining undeveloped SHP capacity;
- Databases of potential sites available for investors;
- Considerable interest from the private sector in SHP development;

- National power development strategy is strongly supportive of large-scale expansion of all RES in general, including SHP.

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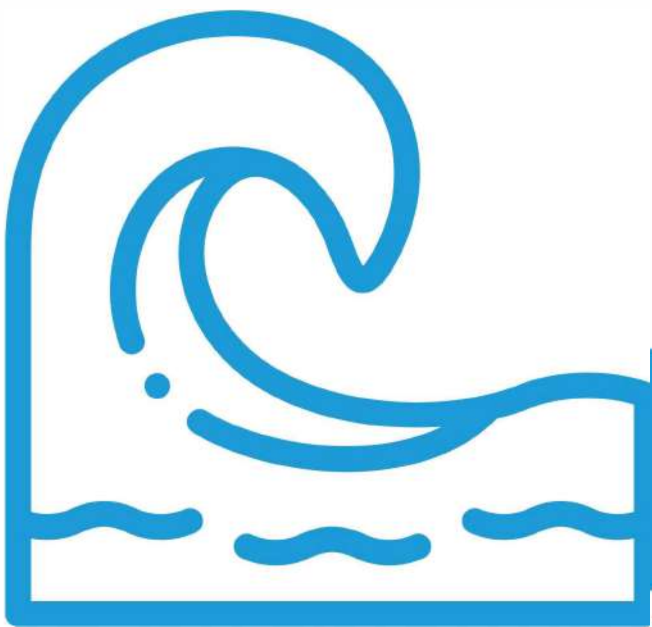


3.5. Western Asia

Countries: Armenia, Azerbaijan, Georgia, Iraq, Israel, Jordan, Lebanon, Saudi Arabia, Syria, Turkey

INTRODUCTION TO THE REGION

The electricity sectors of Western Asia reflect the different resources available to countries in the region. Saudi Arabia and Iraq are major international oil exporters and their energy mixes are dominated by fossil fuels. By contrast, Turkey has a highly diversified energy mix, while Jordan has made considerable investment in solar power as well as wind power to offset its dependence on fossil fuel imports. Ongoing conflict has caused considerable disruptions to the power grids of Iraq and Syria, and Lebanon has been struggling with a multi-faceted economic crisis that has caused a near-collapse of grid-connected generating capacity due to lack of fuel. The electricity sectors of most countries in the region are dominated by state-run companies, although private electricity companies play a significant role in Israel, Armenia and particularly in Turkey.

Turkey leads the region in hydropower development, owing to its abundant water resources. Hydropower is the single most significant energy source in terms of installed capacity in Turkey as well as in Georgia and Armenia, although actual electricity generation from hydropower in Turkey and Armenia lags behind that of other energy sources. In Iraq, Syria, Lebanon and Azerbaijan, hydropower plays a supplementary role, and it forms only a minor part of the electricity mix of Jordan. Due to the presence of transboundary rivers and overall water scarcity in Western Asia, disputes over hydropower resources have contributed to geopolitical tensions and conflict in parts of the region.

An overview of the electricity sectors of the countries in the region is provided in Table 1.

Table 1. **Overview of Western Asia**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Armenia	3	100	100	2,879	7,723	1,346	1,778
Azerbaijan	10	100	100	7,622	25,839	1,149	1,070
Georgia	4	100	100	4,533	11,857	3,323	8,932
Iraq	40	100	100	27,661	87,900	1,864	5,000
Israel	9	100	100	17,972	110,600	N/A	N/A
Jordan	11	N/A	N/A	5,728	20,996	12	18
Lebanon	7	100	100	3,083	14,501	282	424
Saudi Arabia	35	100	100	85,200	340,900	N/A	N/A
Syria	26	89	76	9,803	26,586	1,505	1,614
Turkey	84	100	100	95,890	305,500	30,984	78,116
Total	-	-	-	**260,370**	-	**40,465**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in Western Asia is not uniform. Many countries in the region, including Azerbaijan, Jordan, Lebanon, Syria and Turkey, have adopted the up to 10 MW definition, while Georgia adheres to the up to 15 MW definition and Armenia to the up to 30 MW definition. No official SHP definition exists in Iraq, Israel, or Saudi Arabia.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Western Asia (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Armenia	Up to 30 MW	382.0	430.6	340.0	340.0
Azerbaijan	Up to 10 MW	49.5	520.0	49.5	520.0
Georgia	Up to 15 MW	263.0	723.9	212.2	491.8
Iraq	N/A	N/A	N/A	6.0	62.4
Israel	N/A	N/A	N/A	7.0	7.0*
Jordan	Up to 10 MW	12.0	N/A	12.0	12.0*
Lebanon	Up to 10 MW	31.2	144.8	31.2	144.8
Saudi Arabia	N/A	N/A	N/A	0.0	130.0
Syria	Up to 10 MW	23.0	67.6	23.0	67.6
Turkey	Up to 10 MW	1,662.2	4,891.5	1,662.2	4,891.5
Total	-	-	-	**2,343.1**	**6,667.1**

Source: *WSHPDR 2022*[1]

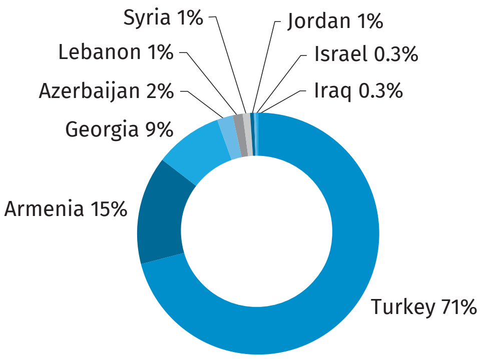
Note: *Based on installed capacity as data on total potential capacity are not available.

The most significant SHP capacities in Western Asia exist in Turkey as well as the countries of the Southern Caucasus, particularly Armenia and Georgia. In other parts of the region, SHP forms only a small part of the total installed hydropower capacity, as regional climatic and topographical conditions make the construction of SHP plants on smaller streams impractical due to their seasonal variability.

The total installed capacity of SHP up to 10 MW in Western Asia is 2,343.1 MW, while the potential capacity is estimated at 6,667.1 MW. The installed capacity of SHP has decreased by nearly 34 per cent relative to the *World Small Hydropower Development Report (WSHPDR) 2019,* while potential capacity has decreased by nearly 16 per cent. The primary reason for this decrease were updates to SHP databases and cancellations of ongoing and prospective SHP projects in Turkey due to economic and environmental factors. At the same time, SHP development in Turkey is ongoing, with several new projects commissioned in 2020, and active development of SHP is taking place in Armenia, Georgia and Azerbaijan. Elsewhere in Western Asia, little activity in the SHP sector has been observed. Countries in the region with limited new stream SHP potential are exploring options for SHP development on existing water supply infrastructure.

The national share of regional installed SHP capacity by country is displayed in Figure 1, while the share of total national SHP potential utilized by countries in the region is displayed in Figure 2.

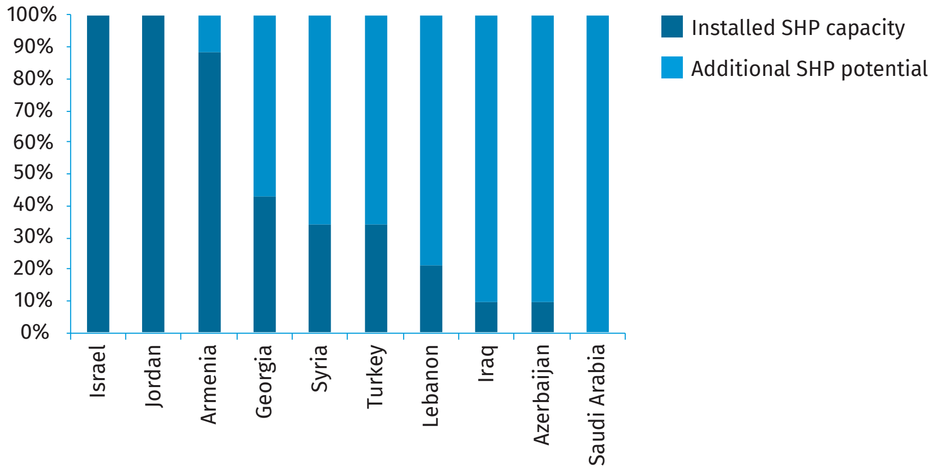
Figure 1. **Share of Regional Installed Capacity of Small Hydropower by Country in Western Asia (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP up to 10 MW.

Figure 2. **Utilized Small Hydropower Potential by Country in Western Asia (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP up to 10 MW in the case of Israel, Georgia, Syria, Turkey, Lebanon, Jordan, Iraq, Azerbaijan and Saudi Arabia; for SHP up to 30 MW in the case of Armenia.

In **Armenia**, there were 188 SHP plants up to 30 MW as of 2021 with a total installed capacity of 382 MW, of which 186 plants were up to 10 MW with a total installed capacity of approximately 340 MW. The potential capacity for SHP up to 30 MW is estimated at 430.6 MW, indicating that approximately 89 per cent has been developed. Ongoing SHP development has included the commissioning of 11 new SHP plants in the last several years, and 24 SHP projects with a total capacity of nearly 49 MW were under construction as of early 2021.

The installed capacity of SHP up to 10 MW in **Azerbaijan** was estimated at 49.5 MW as of 2022 while potential capacity is approximately 520 MW, indicating that nearly 10 per cent has been developed. Several new SHP plants were constructed in the country between 2017 and 2020 and several additional plants formerly operated by the de-facto authorities in Nagorno-Karabakh were refurbished and recommissioned in 2021. In addition, a further 23 non-operational SHP plants are slated for refurbishment in the near future.

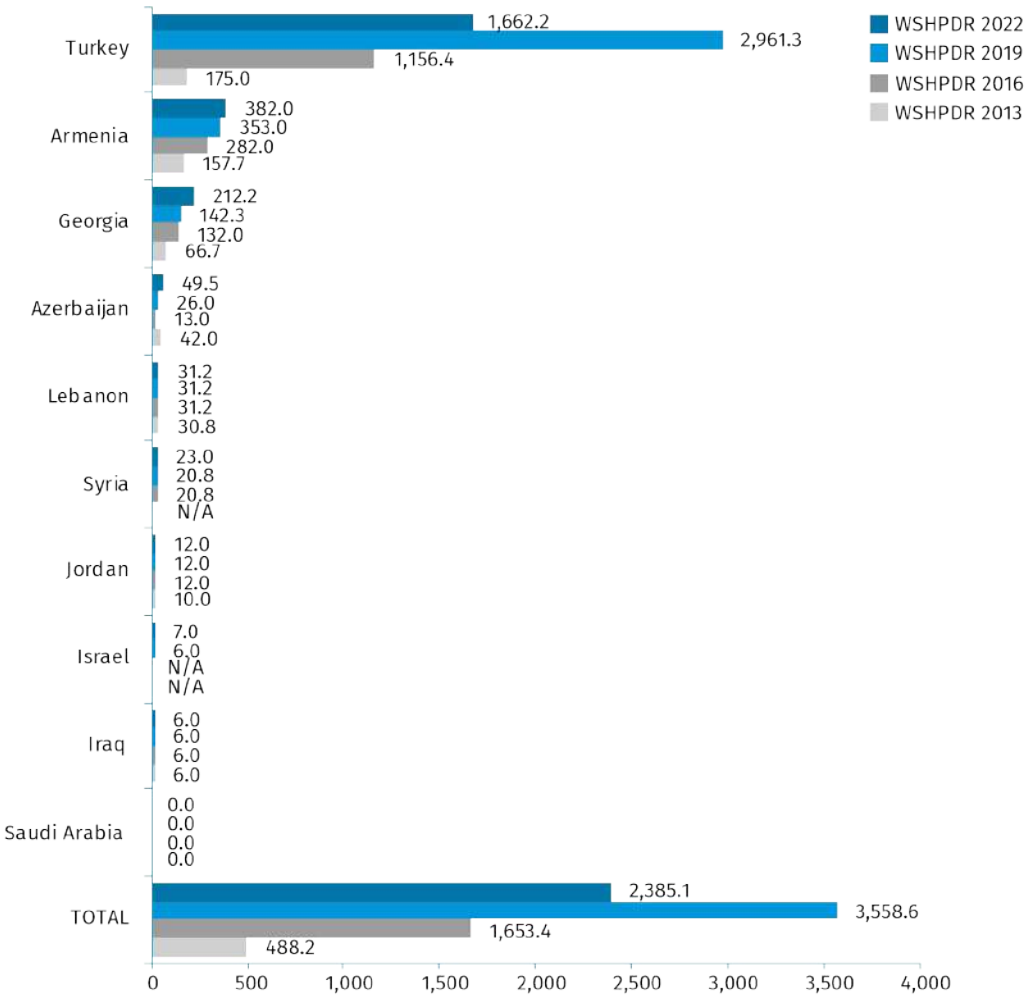
In **Georgia**, the total installed capacity for SHP up to 15 MW was approximately 263 MW as of 2021 and approximately 212 MW for SHP up to 10 MW. The official definition of SHP in the country was altered from up to 13 MW to up to 15 MW in 2019. Under the new definition, there were 72 SHP plants in operation as of 2021, of which 68 were plants up to 10 MW. Potential capacity for SHP up to 15 MW is estimated at 724 MW, indicating that 36 per cent has been developed, and for SHP up to 10 MW at nearly 492 MW, indicating that 43 per cent has been developed. A very large number of SHP plants have been constructed in the country between 2017 and 2020, with capacities ranging from 0.5 MW to 9.5 MW. As of December 2020, there were a total of 74 SHP projects under construction, applying for licences or undergoing feasibility studies.

The installed capacity of SHP in **Iraq** is 6 MW, provided by a single SHP plant. Potential capacity for SHP up to 10 MW is estimated to be at least 62 MW, suggesting that less than 10 per cent has been developed. Currently, there are no plans for SHP development as the country has prioritized solar power and wind power projects.

The total installed SHP capacity in **Israel** is estimated at 7 MW and has not changed over the last decade. Data on specific plants as well as on the total SHP potential in the country are not available. Studies on opportunities for SHP development in Israel as well as experimental projects on SHP installation on water supply infrastructure have been carried out over the last decade, but no specific plans for SHP development in the country have been proposed or implemented.

There are two operational SHP plants in **Jordan**, both constructed in the 1980s, with a total installed capacity of 12 MW, but only one plant is actively producing electricity. There is no reliable data on SHP potential in the country. As of 2021, there were no ongoing SHP projects or official plans for SHP development in the country.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in Western Asia (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

Note: For SHP up to 10 MW in the case of Turkey, Georgia, Azerbaijan, Lebanon, Syria, Jordan, Israel, Iraq and Saudi Arabia; for SHP up to 30 MW in the case of Armenia.

The installed capacity of SHP up to 10 MW in **Lebanon** is 31.2 MW and has not changed in several decades, with the country's still-operational SHP plants constructed during the pre-civil war period. Potential for SHP up to 10 MW has been assessed by several detailed studies and is estimated at 144.8 MW, indicating that 22 per cent has been developed, but there are no plans for further SHP development in the country.

Saudi Arabia has no SHP sector and no plans for the development of SHP. However, untapped SHP potential is estimated to total approximately 130 MW. This potential is mainly accounted for by non-powered dams, including 6 dams with a potential capacity of between 45 MW and 51 MW and 51 smaller dams with a potential capacity of 82 MW.

Syria has three operational SHP plants up to 10 MW with a total installed capacity of approximately 23 MW. The total potential for SHP up to 10 MW in the country is estimated at 67.6 MW, suggesting that 34 per cent has been developed. No significant SHP development has taken place in the country since the 1960s. The Government of Syria has been exploring options for re-energizing the SHP sector as a means to offset the loss of electricity capacity caused by the ongoing conflict and sanctions. A government study commissioned in 2020 conducted a detailed investigation of the potential for SHP development in current conditions, with a particular focus on developing hidden SHP potential found in existing water supply infrastructure, outflow from industrial sites and non-powered dams.

The total installed capacity of SHP up to 10 MW in **Turkey** was 1,662.2 MW as of 2020. The potential capacity was estimated at 4,891.5 MW, indicating that 34 per cent has been developed. Both installed and potential capacity of SHP in the country have decreased considerably relative to the *WSHPDR 2019* following updates to databases of SHP plants and the cancellation of over 600 SHP projects. The causes of these cancellations included technical issues, environmental factors including drought and difficulty in obtaining licences. The private sector plays an important role in SHP development in the country, with 714 SHP plants put into operation under public-private partnerships.

Changes in the installed SHP capacities of countries in the region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Climate Change and Small Hydropower

Several countries in the Western Asia region have limited water resources, and climate models indicate an increase in evaporation and a reduction in rainfall. The long-term effects are expected to have an impact on hydropower generation. For example, Lebanon is expecting a decline in annual hydropower generation of 540 GWh by 2090. In the Caucasus region, impacts vary across river basins. In Armenia, annual river flow is projected to decline by 39 per cent by 2100, significantly impacting SHP as most plants are built on natural watercourses.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Armenia has a wide range of policies that have contributed to active SHP development in the country, including feed-in tariffs (FITs) for SHP differentiating between several categories of projects. At the same time, the regulatory framework for SHP in Armenia has become increasingly strict due to environmental concerns and legislation promoting the use of renewable energy currently favours energy sources other than SHP, in particular solar power. Most importantly, remaining undeveloped SHP potential in the country is nearly exhausted and is likely to be filled by ongoing projects following their completion. Subsequently, opportunities will remain in the area of refurbishment of ageing SHP plants, of which there is a considerable number.

Azerbaijan has considerable undeveloped SHP potential as well as a number of SHP plants in need of immediate refurbishment. The country has recently adopted a new Law on the Use of Renewable Energy Sources in the Production of Electricity that provides for guaranteed purchase tariffs and grid connections for renewable energy projects, in addition to tax exemptions and subsidies provided by previous legislation. However, up-to-date studies on SHP potential in the country are lacking and heavy reliance on electricity generation from cheap domestic fossil fuels presents an obstacle to renewable energy development as a whole.

In **Georgia** there are several factors favouring SHP development, including the structure of the electricity market, which favours independent power producers, as well as commitments on reductions of greenhouse gas emissions by many municipal governments under the Covenant of Mayors framework, which have driven renewable energy development in the country. At the same time, there is a lack of government support for SHP in the form of tax incentives or FITs and only limited local manufacturing capacity. An additional obstacle is the lack of up-to-date information on SHP potential, particularly in view of shifting hydrological conditions due to climate change.

SHP potential in **Iraq** is represented by several undeveloped sites with potential capacities ranging between 5 MW and 10 MW, as well as a large number of non-powered dams and barrages with a total potential capacity of over 26 MW. However, the reliance of Iraq on cheap domestic fossil fuels as well as on large hydropower for electricity generation represents a major obstacle to SHP development, and the country's renewable energy policy is focused on solar and wind power.

There is no clear data on SHP potential in **Israel** and the country's renewable energy policy has prioritized solar power and wind power plants. As elsewhere in the region, one of the main realistic options for SHP development in the country is the installation of micro-hydropower turbines on existing water supply networks.

Opportunities for SHP development in **Jordan** include the installation of SHP on several non-powered dams as well as a number of potential sites for dedicated SHP plant construction identified in a 2012 study. While Jordan is actively pursuing renewable energy development, the country's focus on solar power and wind power is likely to continue into the foreseeable future.

Despite substantial undeveloped SHP potential in the country, further large-scale SHP development in **Lebanon** is unlikely due to the lack of economic capacity for carrying out SHP projects, increasing water stress, low electricity purchase prices by the grid operator and the leading role of other renewable energy sources in driving the energy transition of the country, particularly solar power. Existing SHP plants in the country are in need of refurbishment, which may represent an opportunity for future projects in the sector.

The prospects for SHP development in **Saudi Arabia** are limited due to the lack of permanent rivers and heavy reliance on cheap domestic fossil fuel resources. The main potential for SHP development in the country lies in the installation of SHP plants on non-powered dams, outflow from industrial sites and energy recovery solutions on existing water supply infrastructure, including desalination plants.

Owing to climatic and economic limitations, there are few opportunities for SHP development in **Syria**. The primary options for further activity in the sector include the refurbishment of existing plants and installation of SHP plants on non-powered dams, outflow from water treatment facilities as well as on water supply infrastructure, particularly break pressure tanks.

Turkey has a large SHP sector and prospects for further development of SHP are strong due to a robust technical capacity and a well-established framework of incentives for SHP, including several types of FITs and tax exemptions. At the same time, bureaucratic hurdles and environmental factors including variability of river flows have led to the closure of a large number of projects in recent years. Additionally, certain existing legislation promoting SHP does not set an upper capacity threshold, encouraging developers to pursue larger and more cost-effective projects.

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Armenia

Vahan Sargsyan and Karine Sargsyan, Scientific Research Institute of Energy

KEY FACTS

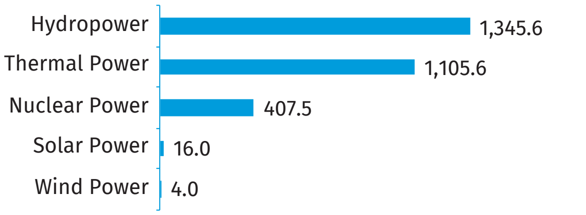
Population	2,963,300 (2020)[1]
Area	29,743 km^2 [1]
Topography	Armenia is a mountainous country with the lowest point near the Debed River in the north, at 375 metres above sea level, and the highest point on the northern peak of Mount Aragats at 4,095 metres. The average altitude is 1,830 metres above sea level, with 90 per cent of the area lying above 1,000 metres, of which 40 per cent is above 2000 metres. Such significant variations in altitude have important effects on the climatic and landscape zones within the country.[2,3]
Climate	Armenia is a country of great climatic diversity. Almost all climatic variations can be observed in the country, including dry subtropical and cold mountainous zones. The average annual air temperature ranges from -8 °C in mountainous areas to 12–14 °C in valley regions. Summer is mild, with an average temperature of 16.7 °C in July and as high as 24–26 °C in the Ararat Valley. Winter is quite cold, with January, the coldest month, averaging a temperature of -6.7 °C. The climate of Armenia is also characterized by intense and abundant solar radiation, with an average annual irradiance of approximately 1,700 kWh/m^2 and 2,500 sunshine hours per year. The average annual wind velocity varies greatly across Armenia: from 1 m/s in Meghri to 8 m/s in Sisian. In the summer, the velocity of the mountain winds can reach 20 m/s or more. The territory of Armenia is characterized by a high frequency and magnitude of hazardous hydrometeorological phenomena, leading to emergency situations.[3]
Climate Change	Significant increase in the annual temperature in Armenia has been observed in the last few decades. Relative to the 1961–1990 annual average of 5.5 °C, the annual average temperature increased by 0.4 °C during the period of 1929–1996 and during the period of 1929–2016 by 1.23 °C. Precipitation during the period of 1935–2016 decreased by almost 9 per cent compared to the annual average (592 mm) for the period 1961–1990.[3]
Rain Pattern	The climate in Armenia is relatively dry, with an average annual precipitation of 592 mm. High mountainous regions receive the greatest amount of precipitation, in the range of 800–1,000 mm annually. The driest regions are the Ararat Valley and Meghri regions, with an average annual precipitation of 200–250 mm. Average precipitation in the Ararat Valley during the summer does not exceed 32–36 mm.[3]
Hydrology	There are approximately 9,500 small and medium rivers flowing through the territory of Armenia, with a total length of approximately 25,000 km. The longest rivers the Akhurian (186 km), Araks (158 km), Debed (154 km), Hrazdan (141 km) and Vorotan (119 km). The density of the river network ranges from 0 to 2.5 km/km^2 in different parts of the country. Rivers in Armenia have a highly uneven flow distribution across years and seasons, with an average surface flow of 6.8 billion m^3. The largest lake in the country is Lake Sevan, located at 1,900.5 metres above sea level, with a surface area of 1,287.7 km^2 and a volume of 38.2 km^3. Besides Lake Sevan, there are approximately 100 small mountain lakes with a total volume of 0.8 km^3. Additionally, 87 reservoirs with a total volume of 1.4 billion m^3 have been constructed in Armenia to address the seasonal fluctuations in the river flow. Groundwater reserves in Armenia account for approximately 4.0 billion m^3. They play an important role in the country's overall water balance, with approximately 96 per cent of the drinking water and more than 40 per cent of the total water intake coming from groundwater. The largest water consumer in Armenia is the irrigation sector.[3]

ELECTRICITY SECTOR OVERVIEW

Armenia possesses rather scarce fossil fuel resources, having no oil reserves, no oil production and no refineries. There are no oil pipelines, and refined products arrive through rail or truck shipments. Thermal power plants are fuelled mainly by natural gas. Domestic primary energy sources, including hydropower, nuclear power, wind power and biomass, contribute approximately 27 per cent of the total primary energy supply, which equalled 3,595.5 ktoe in 2020.[4]

In 2020, total electricity generation was 7,723.4 GWh. Approximately 41 per cent (3,165.6 GWh) was provided by thermal power, 36 per cent (2,756.3 GWh) was provided by nuclear power and 23 per cent (1,778.4 GWh) was provided by hydropower. The contribution of wind and solar power was negligible at approximately 0.3 per cent (23.2 GWh) (Figure 1).[5]

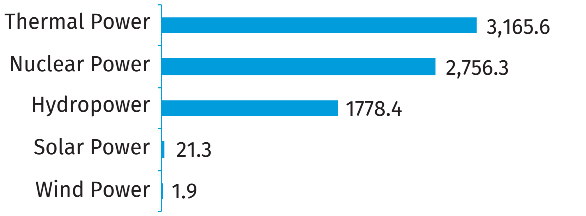
Figure 1. **Annual Electricity Generation by Source in Armenia in 2020 (GWh)**



Source: PSRC[5]

The total installed capacity in Armenia in 2020 was 2,878.7 MW. Approximately 47 per cent of total installed capacity (1,345.6 MW) was from hydropower, 38 per cent (1,105.6 MW) was from thermal power and 14 per cent (407.5 MW) was from nuclear power. Wind and solar power together accounted for less than 1 per cent (20 MW) of the installed capacity (Figure 2).[6] There is also a further 1,284 MW of thermal power capacity from plants and units that are presently out of operation or partly dismantled, and are therefore not included in the total installed capacity.

Figure 2. **Installed Electricity Capacity by Source in Armenia in 2020 (MW)**



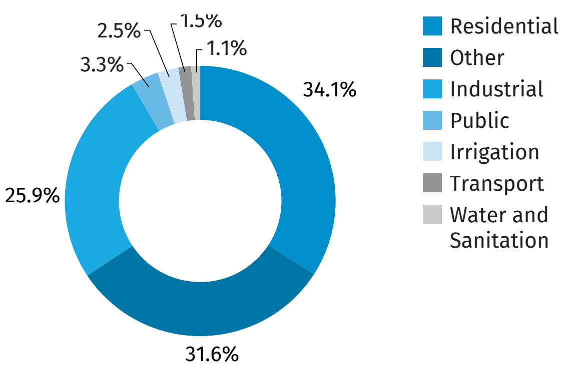
Source: Government of the Republic of Armenia[6]

The one nuclear power plant operating in Armenia (ANPP) meets between 30 and 50 per cent of the country's electricity needs depending on plant uptime. There is international pressure on Armenia to decommission this plant due to perceived seismic risk. However, the Government is reluctant to do so until alternative generating capacity is online and the plant is scheduled to operate until 2026. Hydropower plants are represented by two cascades (Sevan-Hrazdan and Vorotan) and a number of small hydropower (SHP) plants. Hydropower meets between 20 and 40 per cent of the country's electricity needs depending on the amount of rainfall, which exhibits significant annual variation. There are also three condensed-type gas-fired thermal (CCGT) plants in operation, which cover the remaining electricity demand and are responsible for ensuring electricity exports to neighbouring countries. It is worth noting that Armenia is not only fully supplied with electricity over its entire territory, but is in fact equipped with excess installed capacities, due to a 2.5 decrease in electricity consumption since the end of the Soviet period.

The past few years have been marked by wide implementation of different solar installations such as rooftop solar photovoltaic (PV) installations, grid-connected solar power plants, solar water heaters, etc. There has also been some development of SHP capacities. The share of electricity generated from renewable sources in 2020 exceeded 23 per cent, provided almost entirely by hydropower.[5] Generation by solar and wind power has lagged behind the installed capacity of these energy sources, due to the low efficiency of many of the installed solar PV panels in Armenia and the temporary non-operational status of a number of installed wind turbines.

Armenia has interconnections with all neighbouring countries, but high voltage lines are under operation only with Georgia and Iran. In 2020, total electricity imports amounted to 320.3 GWh and exports to 1,333.1 GWh. Electricity consumption reached 5,810.4 GWh, with the residential sector accounting for 34 per cent of total consumption, the industrial sector for 26 per cent and the public sector, transport, irrigation, water supply and sanitation and other uses for the remaining 40 per cent (Figure 3).[5] The electrification rate in the country is 100 per cent.[7] Customers have full access to the electricity network and grid connection is available to any new user.

Figure 3. **Electricity Consumption by Sector in Armenia in 2020 (%)**



Source: PSRC[5]

The High Voltage Electric Networks (HVEN) Closed Joint-Stock Company (CJSC) is responsible for transmitting the power produced by generating companies to the distribution company, as well as for transporting both electricity imports and exports from and to neighbouring countries.[8] Another private company, the Electric Networks of Armenia CJSC (ENA), is responsible for distribution and is the sole buyer of power from all generating companies, as well as the sole seller of power to all customers at tariffs set by the Public Services Regulatory Commission of the Republic of Armenia (PSRC).[9] The ENA's distribution grid includes all lines and substations within the 0.4–110 kV range and all SHP plants in the country are connected exclusively to the distribution grid.

The PSRC is an independent regulatory authority, whose functions include drafting of the tariff methodology and approval of tariffs, issuing of licences and permits, development and control of service quality standards, review of customers' complaints and approval of investment plans.[10] The Government of Armenia does not provide subsidies to either consumers or producers of energy and all costs related to electricity pricing fall on the ENA. The ENA is obligated to purchase power from producers at the tariffs set by the PSRC and guarantees purchase of power from all licensed producers. The PSRC and ENA coordinate to ensure an adequate level of profit for the ENA, including adjusting tariffs to compensate for periods where ENA has incurred losses due to insufficient demand.

The tariffs for all final consumers set by the PSRC depend on the level of the feeding voltage and on the hours of usage. The consumer tariffs in effect as of 29 December 2020 are presented in Table 1.

Table 1. **Electricity Tariffs for Consumers in Armenia as of 29 December 2020**

	Price incl. VAT (AMD (USD) per kWh)	
Consumer type	*Day time*	*Night time*
110 kV and above voltage consumers	36.48 (0.075)	32.48 (0.070)
35 kV voltage consumers	38.98 (0.080)	34.98 (0.072)
6 (10) kV voltage consumers	44.98 (0.092)	34.98 (0.072)
0.38 kV voltage consumers (non-residential)	47.98 (0.098)	37.98 (0.077)
0.38 kV voltage residential consumers consuming more than 400 kWh/month	47.98 (0.098)	37.98 (0.077)
0.38 kV voltage residential consumers consuming up to 400 kWh/month (inclusive)	44.98 (0.092)	34.98 (0.072)
Residential low-income consumers	29.99 (0.061)	19.99 (0.041)

Source: PSRC[11]

Note: Night time tariffs are from 22:00 PM to 06:00 AM starting from the last Sunday of March until the last Sunday of October; and from 23:00 PM to 07:00 AM starting from the last Sunday of October until the last Sunday of March.

The Electro Power Systems Operator CJSC, otherwise known as the National Dispatch Centre, is responsible for the maintenance of technically admissible steady-state operations of the electricity network. It also manages the network in power emergencies and its restoration to acceptable operating conditions following such emergencies.[12] The Settlement Centre CJSC collects and processes data on power flows in the electricity network and on technical parameters of the regime by means of an automated data acquisition and metering system, as well as provides the processed data to other market participants.[13]

To promote the gradual liberalization of the electricity market and interstate trade, on 7 February 2018 the National Assembly of the Republic of Armenia adopted amendments and addenda to the laws "On Energy", "On Licensing" and "On State Duty", taking into account recommendations made by international organizations.[14,15,16] These decisions marked the beginning of the process of liberalization of the Armenian electricity market. The "Program-Timeline of Measures towards Liberalization and Interstate Trade Development of the Electricity System of the Republic of Armenia" was adopted by Government Decree No. 1010-L from 14 September 2018.[17]

The liberalization of the Armenian electricity market means that the market will move from a "one buyer" model to a free electricity purchase and sale mechanism. "Temporary commercial rules of the wholesale electricity market of the Republic of Armenia" were approved by Resolution of the Public Services Regulatory Commission (PSRC) No. 344 from 9 August 2017, which defined the participants of the wholesale electricity market and its structure and regulates commercial relations among participants.[18,19,20]

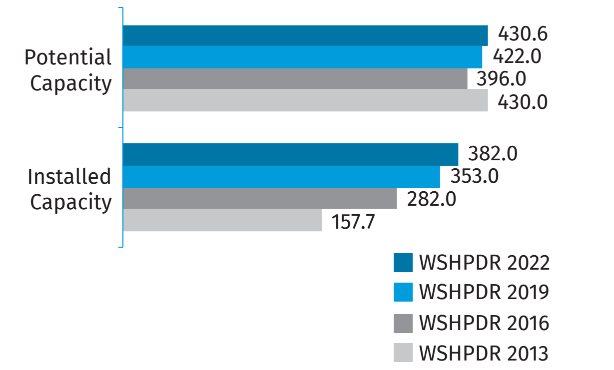
New trade rules for the electricity wholesale and retail markets in the Republic of Armenia, as well as network rules for transmission and distribution, sample forms of relevant contracts and indicators for safety and reliability were outlined by PSRC Resolutions No. 516-N and No. 523-N from 25 December 2019. These amendments, which are to be applied from 1 February 2021, should ensure the introduction of the new electricity market model.[21,22] The "Republic of Armenia Energy Sector Development Strategic Programme to 2040", approved by Government Decision 48-L from 14 January 2021 and superseding previous strategic energy documents, outlines the planned vectors of development of the energy sector. Major elements of the Programme include the wide implementation of solar PV and the full utilization of all remaining economically viable hydropower potential, in particular SHP. It is expected that all new power plants will be constructed on a public-private partnership (PPP) basis or entirely through private investments.[23]

SMALL HYDROPOWER SECTOR OVERVIEW

On the basis of Government Decision No. 1300-A from 8 September 2011, SHP plants are defined as those with installed capacity less than 30 MW.[24]

As of 1 January 2021, 188 SHP plants up to 30 MW with a total installed capacity of 382 MW and average annual generation of approximately 951.7.6 GWh were in operation in Armenia. Of these, 186 plants were SHP plants up to 10 MW with a total installed capacity of approximately 340 MW.[25] The list of 20 most recently commissioned SHP plants is presented in the Table 2. The potential capacity of SHP up to 30 MW, based on the number of existing plants and licensed projects, is 430.6 MW.[25] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity increased by approximately 8 per cent, and potential capacity by approximately 2 per cent (Figure 4).[26] The increase is primarily accounted for by the construction of 11 new SHP plants and the granting of several additional licenses for future projects, respectively.

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Armenia (MW)**



Source: PSRC,[25] *WSHPDR 2019*,[26] WSHPDR *2013*,[27] *WSHPDR 2016*[28]

Note: Data for or SHP up to 30 MW.

Table 2. **List of Selected Operational Small Hydropower Plants in Armenia**

Name	*Location*	*Capacity (MW)*	*Head*	*Plant Type*	*Operator*	*Launch year*
Astghaberd	Syunik	7.795	165	Run-of-river	TELIA MINING LLC	2020
Kaputjugh	Syunik	1.227	120	Run-of-river	AREV EV JUR LLC	2020
Aygdzor	Tavush	0.440	105	Irrigation system, run-of-river	Atlas-Energo LLC	2019
Aparan	Aragatsotn	1.512	27	Irrigation system, run-of-river	NIGAVA LLC	2019
Garni	Kotayk	1.333	184	Run-of-river	Narenergo LLC	2019
Gornar	Vayots Dzor	3.908	542	Irrigation system, run-of-river	GREEN ENERGY AMERICAN CONCERN LLC	2018
Her-Her	Syunik	1.200	34	Irrigation system, run-of-river	Her-Her HPP CJSC	2018
Sahakyan SHPP-2	Lori	2.434	103	Run-of-river	Energostil CJSC	2018
Qajarants	Syunik	3.081	203	Run-of-river	SUN AND WATER LLC	2018
Chqnacgh	Syunik	3.310	221	Run-of-river	GREEN POWER LLC	2018
Jermuk-1	Vayots Dzor	2.547	65	Run-of-river	Jermuk Turboshin LLC	2018
Meghri-1	Syunik	2.400	88	Run-of-river	GREEN POWER LLC	2017
Arpa-2	Syunik	2.775	316	Run-of-river	GINJ ARPA LLC	2017
Arpa-3	Syunik	3.600	131	Run-of-river	GINJ ARPA LLC	2017
Kok	Tavush	0.973	18	Run-of-river	KOK SYSTEM LLC	2017
Vorotan-7	Syunik	3.610	106	Run-of-river	VOROTAN SYSTEMS LLC	2017
Gndevank	Vayots Dzor	1.500	165	Run-of-river	FERA LLC	2017
Amberd SHPP-3	Aragatsotn	9.830	293	Run-of-river	Amberd HPP LLC	2017
Seka	Syunik	1.040	122	Run-of-river	KARALEVAS LLC	2016
Anapat-1	Syunik	3.887	293	Run-of-river	TATEV ANAPAT LLC	2016

Source: PSRC[25]

As of 1 January 2021, 24 ongoing SHP projects with a total installed capacity of 48.6 MW and an expected annual electricity production of approximately 173 GWh had licences and were under construction.[25] Data on the five most recent SHP projects are displayed in Table 3.

Table 3. **List of Selected Ongoing Small Hydropower Projects in Armenia**

Name	*Location*	*Capacity (MW)*	*Head*	*Plant Type*	*Developer*	*Planned Launch Year*	*Development Stage*
Tashir	Lori	0.990	32	natural water flow	Stepdzor LLC	2021	Under construction
Eri Dzor	Tavush	0.990	222	Irrigation system	Atlas-plus LLC	2021	Under construction
Akhuryan SHPP-2	Shirak	2.418	39	natural water flow	Musaha LLC	2022	Under construction
Chanakhchi HPP-2	Lori	0.260	102	natural water flow	Mavr LLC	2022	Under construction
Jimel	Syunik	0.400	234	Irrigation system	JIMEL LLC	2023	Under construction

Source: PSRC[25]

Note: As of January 2021.

The theoretical generation potential of hydropower in Armenia is estimated at 21,800 GWh/year, including 18,600 GWh/year for large and medium rivers and 3,200 GWh/year for small rivers. Technically available potential is estimated at approximately 7,000–8,000 GWh/year and economically feasible potential at 3,200–3,500 GWh/year.[29]

RENEWABLE ENERGY POLICY

The Republic of Armenia Energy Sector Development Strategic Programme to 2040 sets the maximum use of renewable energy potential as the primary development priority. Among other targets, the programme envisages wide implementation of solar PV (approximately 1,000 MW), as well as sets targets to construct approximately 50 MW of SHP capacity by 2023.[23] The Armenian Energy system least-cost development study, which was the basis for the preparation of the Strategic Programme, shows that greenhouse gas (GHG) emission reduction targets under Armenian Nationally Determined Contribution (NDC) could be achieved only through the full implementation of the mentioned renewable energy projects together with the extension of the service of the nuclear power capacities currently available in the country.[30]

Laws adopted in recent years to support and regulate renewable energy development include amendments and supplements to the Law on Energy aimed at the creation of conditions conducive to the advancement of renewable energy sources:

- A 20-year purchase guarantee provision is established for electricity produced by renewable energy sources other than SHP, for which the old 15-year purchase guarantee applies; it is assumed the investor will recoup the cost of development within this period;
- Activities which are not subject to regulation only include the production of electricity exclusively for self-consumption purposes, as well as the production of electricity by autonomous producers with an installed capacity of up to 150 kW during the period of production;
- The 150 kW capacity limit for autonomous solar power plants not subject to regulation during the construction and production periods has been replaced by a 500 kW capacity limit for the 2018–2022 period.[31,32,33,34,35,36]

Additional legislative changes have included amendments to the Law on Energy Saving and Renewable Energy, aimed at creating an enabling environment for the operation of solar power plants by establishing a procedure for interconnections between an autonomous power generator and an electricity distribution licence holder.[37,38,39] Meanwhile, the 2019 Law on Making Addendum and Amendments to the Water Code of the Republic of Armenia includes the following regulations, specifically relevant to SHP development:

- Defines specifies zones where construction and operation of SHP plants are prohibited;
- Establishes grounds for refusing applications for water use permits for newly constructed SHP plants. The Government hereby reserves the authority to define the list of rivers which provide habitats for the spawning of endemic fish species included in the IUCN Red List of Threatened Species.[40,41,42,43]

Renewable energy development in Armenia is promoted in part through the tariff policy set by the PSRC, which currently favours solar PV. The tariff policy is based on the principle of ensuring adequate revenue levels for producers and is aimed at sustaining normal economic activity in this sphere and balancing the interests of consumers and regulators, while also enabling the implementation of prospective development projects. A fixed tariff system is applied for plants using renewable energy sources. Within the framework of this system the tariffs are adjusted every year, taking into account inflation and fluctuations in the AMD/USD exchange rate. This targeted policy has already had significant success, as evidenced by the recent rapid development of solar PV plants in Armenia.

Feed-in tariffs (FITs) for electricity produced by SHP plants effective from 1 July 2021 until 1 July 2022, are as follows (exclusive of VAT of 20 per cent):

- For SHP plants built on natural water streams: 26.185 AMD/kWh (0.053 USD/kWh);
- For SHP plants built on irrigation systems: 17.454 AMD/kWh (0.035 USD/kWh);
- For SHP plants built on natural drinking sources: 11.637 AMD/kWh (0.023 USD/kWh).[44]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Licensing of electricity generating companies is the sole right of the PSRC. There is a unified procedure to obtain a licence, which applies to all types of electricity producers, including SHP. The issuing of the licence by the PSRC after examination of the application package is contingent on adherence to standards and norms. The list of documents to be submitted with an application for an electricity licence includes the following items:

- Business plan;
- Certificate of ownership or lease of the applicant's land;
- Announcement on the official website of public notices of the Republic of Armenia;
- Guarantee from the bank on compensation in case of violation of the terms of the licence by the applicant;
- Water use permit for hydropower plants, as well as for other types of plants if required by law;
- A contract or permit establishing connection and construction access for the applicant to water infrastructure owned by other parties in the case of hydropower plants built on drinking water pipes or irrigation systems;
- Certificate of the possibility of connection to the electricity network;
- In case of a PPP transaction, a copy of the PPP agreement.[45]

It should be noted that the 50 MW SHP target set by the Energy Sector Development Strategic Programme to 2040 has significant implications for SHP prospects in the country. As of 2021, the target had been nearly achieved by already-licensed and ongoing projects, with a total planned capacity of 48.6 MW. Therefore, little room remains for additional SHP development, as no new SHP licences are likely to be issued for the foreseeable future.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Projected changes in river flow in Armenia vary across different river basins due to differences in the basins' natural and climatic characteristics, as well as in other factors contributing to flow formation. Annual river flows are projected to decline by up to 14 per cent by 2040, 28 per cent by 2070 and 39 per cent by 2100, relative to the baseline annual average for 1961–1990 (6,279.9 million m^3). A reduction in river flow can be expected to affect SHP generation in Armenia, as most SHP plants in the country are built on natural watercourses.[3]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

A number of legislative improvements introduced in recent years, as well as the strengthening of environmental and technical requirements for SHP plants, led to an improvement in the technical and economic characteristics of new SHP projects. At the same time, these changes have created additional obstacles to SHP development, primarily due to the increasing cost of investment. The main barriers to SHP development at the current stage include the following:

- Issues related to reduction of water reserves due to climate change;
- Increasingly stringent technical and environmental requirements for new SHP projects;
- Due to the wide implementation of SHP in the past decades, there remain very few economically feasible sites for building new SHP plants;
- Most significantly, the 50 MW target for SHP development to 2040 has been nearly fulfilled and no new licences are likely to be issued in the near future.

At the same time, several positive factors for SHP development in Armenia exist, including:

- The high priority assigned to the development of renewable energy by the Government of Armenia in the Energy Sector Development Strategic Programme to 2040;
- Better transparency in regard to necessary requirements and documentation than in the past;
- Existence of promotional tariffs for SHP plants that are expected to cover the costs of development and ensure an adequate level of profit for investors and operators during the 15-year guaranteed purchase period;
- Relatively low interest rates for green loans offered by many Armenian banks;
- There is a consensus that some of the many existing SHP plants in Armenia suffer from problems related to age, substandard construction and poor performance of installed equipment. These issues may present an opportunity for refurbishment and upgrades on existing SHP plants.

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Azerbaijan

Danila Podobed, International Center on Small Hydro Power (ICSHP)

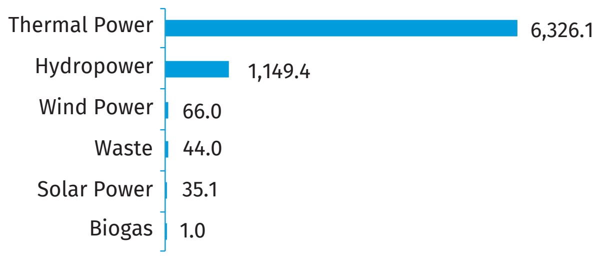
KEY FACTS

Population	10,067,100 (2020)[1]
Area	86,600 km^2[2]
Topography	The topography of Azerbaijan is primarily mountainous in the west and north of the country, while the central parts of the country, the Caspian Sea coastline in the east and much of the southern border with Iran are dominated by hills and lowlands. The highest point in the country is Mount Bazarduzu at 4,466 metres above sea level.[2,3]
Climate	Azerbaijan hosts a variety of climates across its territory and includes subtropical, semi-arid and temperate regions, with the subtropical climate being most typical. Average temperatures range between 12 °C and 16 °C but can reach highs of up to 46 °C and lows of -32 °C.[3]
Climate Change	Observed climate change in Azerbaijan since 2000 has included a rise in temperatures across the country of between 0.4 °C and 1.5 °C, as well as a decrease in precipitation of approximately 10 per cent, relative to the preceding 1971–2000 period. Climate change models predict a further increase in temperatures of 1–2 °C during the 2020–2040 period, relative to the 1971–2020 baseline.[3]
Rain Pattern	Annual precipitation averages less than 400 mm across 65 per cent of the territory of Azerbaijan, amounting to just 150–200 mm on the Absheron Peninsula but reaching as high as 1,600–1,700 in the foothills of the Talysh Mountains. Permanent snowpack exists in parts of the Greater Caucasus Mountain Range.[3]
Hydrology	There are more than 8,350 rivers in Azerbaijan, but 65 per cent of the river flow originates in neighbouring countries. The largest river in Azerbaijan is the Kura, which flows through Turkey, Georgia and Azerbaijan before emptying into the Caspian Sea and has a total length of 1,555 kilometres. The second largest is the Araz River, a tributary of the Kura, which marks the border with Turkey and Iran and has a total length of 1,072 kilometres. There are approximately 450 lakes in the country, of which the largest is Lake Sarysu, as well as 140 artificial reservoirs with a total volume of 21.5 km^3.[3]

ELECTRICITY SECTOR OVERVIEW

The installed electricity capacity of Azerbaijan was 7,621.6 MW in 2020, of which 6,326.1 MW (83 per cent) was provided by fossil fuel-fired thermal power plants, 1,149.0 MW (15 per cent) by hydropower, 66.0 MW (1 per cent) by wind power, 44.0 MW (1 per cent) by waste-fired power plants, 35.1 MW (less than 1 per cent) by solar power and 1.0 MW (less than 1 per cent) by biogas (Figure 1).

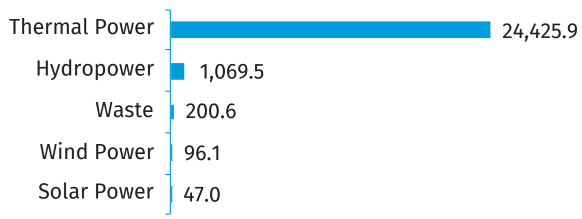
Figure 1. **Installed Electricity Capacity by Source in Azerbaijan in 2020 (MW)**



Source: State Statistical Committee of the Republic of Azerbaijan[4]

Annual electricity generation in Azerbaijan in 2020 amounted to 25,839.1 GWh, with 24,425.9 GWh (95 per cent) provided by thermal power plants, including self-producers, 1,069.5 GWh (4 per cent) provided by hydropower, 200.6 GWh (1 per cent) provided by generation from waste, 96.1 GWh (less than 1 per cent) provided by wind power and 47.0 GWh (less than 1 per cent) provided by solar power (Figure 2).

Figure 2. **Annual Electricity Generation by Source in Azerbaijan in 2020 (GWh)**



Source: State Statistical Committee of the Republic of Azerbaijan[4]

Access to electricity in Azerbaijan is 100 per cent.[5] Consumption of electricity in 2020 totalled 22,759.7 GWh, with the industrial, residential, and commercial and public sectors accounting for 33 per cent, 31 per cent and 25 per cent of all consumption, respectively. The agricultural, construction and transportation sectors accounted for the remaining 11 per cent. Imports of electricity in 2020 amounted to 136.5 GWh, while exports were 11.7 GWh.[4]

The electricity sector in Azerbaijan is dominated by large state-owned enterprises. The largest electricity producer in the country is Azerenergy, a state-owned company which owns and operates most generating capacities as well as the transmission grid. Azerishiq, formerly the Baku Electric Company, is another state-owned enterprise, which assumed control of the country's distribution grid in 2015. Plans to privatize some state-owned power plants were launched in 2018, with a working group established to identify facilities suitable for privatization and to attract private investors.[6,7]

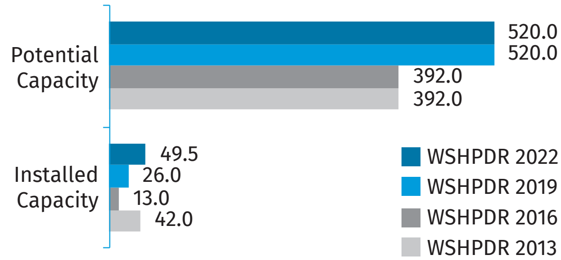
Azerbaijan is a major oil and gas exporter and the domestic electricity sector has been dominated by fossil fuel-fired thermal power plants, with hydropower and other renewable energy sources (RES) playing a secondary role. Recent development plans have targeted the refurbishment of old plants, the construction of new efficient thermal power plants in order to optimize domestic use of fossil fuels and allow an increase in exports, as well as the development of RES, in particular solar power.[7,8,9,10,11] These efforts have included the commissioning of the 409 MW Shimal-2 thermal power plant and the refurbishment of 2 220 kV and 15 110 kV substations in 2019, as well as the Aghdam-1 and Aghdam-2 substations, the Gobu substation and the 385 MW Gobu thermal power plant in 2022.[3,12]

Electricity tariffs in Azerbaijan are regulated by the Tariff (Price) Council of the Republic of Azerbaijan. Tariffs for residential consumers current as of November 2021 were 0.08 AZN/kWh (0.047 USD/kWh) for consumption of up to 200 kWh/month, 0.09 AZN/kWh (0.053 USD/kWh) for consumption of 201–300 kWh/month and 0.13 AZN/kWh (0.076 USD/kWh) for consumption of over 300 kWh/month.[13]

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) is defined in Azerbaijan as hydropower plants with an installed capacity up to 10 MW.[6] The total installed capacity of operational SHP plants in Azerbaijan as of 2022, excluding some SHP plants under the control of the de-facto authorities of the unrecognized Republic of Nagorno-Karabakh, was 49.53 MW, while SHP potential in Azerbaijan has been estimated at 520 MW.[6,14,15,16,17,18,19] This indicates that nearly 10 per cent of the potential capacity has been developed. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP operated by Azerbaijan increased by approximately 92 per cent as a result of territorial changes that followed the 2020 Nagorno-Karabakh War, as well as the refurbishment and construction of SHP plants.[6,14,15,16,17,18] The estimate of potential capacity has remained the same due to a lack of more recent studies (Figure 3).[6,19]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Azerbaijan (MW)**



Source: *WSHPDR 2019*,[6] Report News Agency,[14,15] Hydropower Congress,[16] Babayeva,[17] Ministry of Energy,[18] Aghjayev,[19] *WSHPDR 2013*,[20] *WSHPDR 2016*[21]

As of the end of 2017, the total installed capacity of SHP plants operated by Azerbaijan was approximately 26 MW from 11 plants.[6] In 2019, a 300 kW mini-hydropower plant was installed on the cooling water outflow channel of the newly commissioned Shimal-2 thermal power plant, and the Oguz 1, 2 and 3 SHP plants with a combined capacity of 3.6 MW were commissioned between 2018 and 2020.[16,17,18] Following the results of the 2020 Nagorno-Karabakh War, Azerbaijan gained control of significant territories previously administered by the de-facto authorities of the Republic of Nagorno-Karabagh, as well as of 30 hydropower plants constructed on these territories over the previous few decades with a combined installed capacity of approximately 130 MW. Most of these plants were out of operation following the end of hostilities and the Government of Azerbaijan launched a programme to recommission the plants and link them to the national grid of Azerbaijan.[22,23] In 2021, the 8.0 MW Gulabird SHP plant, the Sugovushan-1 and Sugovushan-2 SHP plants with a combined capacity of 7.8 MW and the 4.0 MW Kalbajar SHP plant were recommissioned following refurbishment.[14,15] The Government plants to relaunch another 23 hydropower plants in the Kalbajar and Lachin districts, including 5 SHP plants in 2022 with a combined capacity of 27 MW.[23] A list of SHP plants operated by Azerbaijan as of 2022 is displayed in Table 2.

The technically feasible potential capacity of SHP plants in Azerbaijan has been estimated at 650 MW and the economically feasible potential at 520 MW.[6,24] The latter figure is considered official by the Ministry of Energy of Azerbaijan as of 2022.[19] However, with the inclusion of non-operational SHP plants in the Kalbajar and Lachin districts, the actual potential may be higher.

Table 2. **List of Small Hydropower Plants Operated by Azerbaijan in 2022**

Name	*Capacity (MW)*
Gulabird	8.00
Vayxir	5.00
Sugovushan-1	4.80
Mughan	4.05
Kalbajar	4.00

Name	*Capacity (MW)*
Oguz 1, 2 and 3	3.60
Goychay	3.10
Chichakli	3.00
Sugovushan-2	3.00
Shekii	1.88
Astara	1.70
Ismayilli-1	1.60
Ismayilli-2	1.60
Balakan-1	1.50
Arpachay-2	1.40
Qusar	1.00
Shimal-2 SHP	0.30
Total	**49.53**

Source: *WSHPDR 2019*,[6] Report News Agency,[14,15] Hydropower Congress,[16] Babayeva,[17] Ministry of Energy[18]

RENEWABLE ENERGY POLICY

The Government of Azerbaijan is heavily invested in developing the RES capacity of the country, among other reasons, as a means to free additional oil and gas resources for export and build international ties. In 2017, Azerbaijan made a significant step in transitioning towards RES development by committing to a 35 per cent reduction of greenhouse gas (GHG) emissions by 2030 as part of the Paris Climate Agreement in 2017, and expanded this commitment to a 40 per cent reduction of GHG emissions by 2050 at the COP26 conference in 2021.[25] The Ministry of Energy has set a target of reaching a 30 per cent share of RES in total electricity generation by 2030, aiming to achieve this goal through commissioning an additional 440 MW in RES capacities in 2023, 460 MW in 2023–2025 and 600 MW in 2026–2030.[12,25]

Over the course of 2021–2022, activity in the RES sector of Azerbaijan accelerated rapidly. In 2021, the Government of Azerbaijan signed agreements with Masdar of the United Arab Emirates for the construction of a 230 MW solar power plant in the Absheron district and with BP for the construction of a 240 MW solar power plant in Zangilan and Jabrail. In January 2022, the Saudi company ACWA Power commenced construction of the 240 MW Khizi-Absheron wind power plant, which is to be completed by 2023. As of 2022, memorandums of understanding on other RES projects have been signed with a total of 11 major companies, including Masdar, ACWA Power, BP, Total, Equinor and others.[12]

This activity was supplemented by long-awaited legislative changes providing a regulatory framework for RES development and incentives for RES projects, including the Presidential order Azerbaijan 2030: National Priorities for Socio-economic Development and the Law on the Use of Renewable Energy Sources in the Production of Electricity (Law on Renewable Energy), both adopted in 2021.[25,26] In particular, the Law on Renewable Energy provides for a guaranteed purchase tariff for RES projects, with the tariff to be either determined at auctions or through direct negotiations with the Ministry of Energy.[25] Additional incentives provided by the Law on Renewable Energy include:

- Guaranteed offtake of generated electricity;
- Guaranteed connection for RES projects;
- Creation of a database of potential RES projects, to be maintained by the Ministry of Energy, that would include information on potential locations and capacities, land ownership and boundaries, population and other information relevant for RES investors.[25,26,27]

Incentives for RES development established by previous legislation additionally include a seven-year tax exemption for investors and technology parts involved in RES development, exemptions from the value-added tax (VAT) and customs duties for imports related to RES projects, a 25 per cent subsidy on RES investments from the Azerbaijan Investment Company and a long-term credit line provided by the Entrepreneurship Support Fund.[6,24]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Certain barriers exist to SHP development in Azerbaijan, including the following:

- Lack of up-to-date studies on SHP potential in the country;
- Problems with grid connections;
- Low cost of electricity due to abundant fossil fuel resources.

However, the climate for SHP development in the country could be generally described as favourable, with enabling factors including the following:

- Considerable untapped SHP potential identified in previous studies;
- Non-operational SHP plants requiring refurbishment or modernization;
- Domestic expertise and technical capacity in the SHP sector;
- Government commitments to RES development in general and to the development of SHP in particular;
- Incentives for RES development in the form of RES auctions, tax exemptions and state investment subsidies;
- Active interest on the part of international investors in RES development in Azerbaijan;
- Active development of grid capacities to keep pace with generating capacity.

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Georgia

Gurami Mirinashvili, Georgian State Electrosystem; Manana Dadiani, Energy Efficiency Centre Georgia

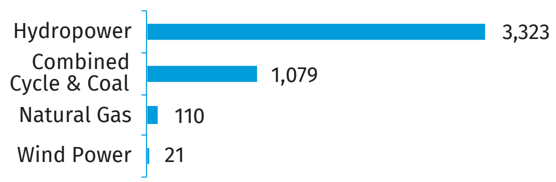
KEY FACTS

Population	3,716,900 (2020)[1]
Area	69,700 km^2 [2]
Topography	More than half of the surface area of Georgia is represented by a mountainous landscape located at an altitude of 1,000 metres or above. Most of the country's territory is located in the Caucasus Mountains and its northern border is partly defined by the Greater Caucasus Range. In addition to the Great Caucasus, other mountain ranges include the Lesser Caucasus, which runs parallel to the borders with Turkey and Armenia, and the Likhi Range, which runs from north to south dividing the country into its eastern and western regions. The highest point in the country is Mount Shkhara, which reaches 5,069 metres above sea level. The central lowlands form a structural depression on the southern slopes of the Greater Caucasus range, while the Kolkhida Lowland dominates the eastern coastline on the Black Sea.[3,4]
Climate	Western Georgia has a humid subtropical, maritime climate, while eastern Georgia has a range of climates varying from a moderately humid to a dry subtropical one. Average annual temperatures are between 14 °C and 15 °C with extremes ranging between 45 °C and –15 °C. The Black Sea influences the climate of western Georgia resulting in mild winters between December and February and hot summers between June and August. In the mountainous and high mountainous areas, temperatures range from between 6 °C and 10 °C to between 2 °C and 4 °C. The highest lowland temperatures occur in July and are approximately 25 °C, while average January temperatures over most of the region are between 0 °C and 3 °C.[2]
Climate Change	According to the country's Fourth National Communication on Climate Change to the United Nations Framework Convention on Climate Change, the process of climate change in Georgia is advancing. Compared to the period between 1956 and 1985, the annual average temperature in 1986–2015 increased in almost all regions of the country. The increase in average temperatures has varied by region, falling within the range of 0.25–0.58 °C. The country-wide average temperature increase was 0.47 °C for the latter period. Additionally, average maximum and average minimum temperatures have also shown an increasing trend in most of the regions of Georgia.[5]
Rain Pattern	Western Georgia receives heavy rainfall throughout the year totalling between 1,000 mm and 2,500 mm. The Southern Kolkhida region in the south-east of the country receives the most rain. In eastern Georgia, precipitation decreases with distance from the sea, reaching between 500 mm and 800 mm in the plains and foothills but increasing to double this amount in the mountains. The south-eastern regions receive the least precipitation in the country, with the driest period being in winter between December and February and the wettest at the end of spring in May.[2,3]
Hydrology	There are 26,000 rivers in Georgia, 99.4 per cent of which have a length of less than 25 km. More than 70 per cent of water power sources are concentrated in the five main river basins: the Rioni (22 per cent), Mtkvari (16 per cent), Inguri (15 per cent), Kodori (9 per cent) and Bzibi (8 per cent). There are also approximately 860 freshwater lakes in Georgia with a total surface area of 170 km^2.[6]

ELECTRICITY SECTOR OVERVIEW

The total installed electricity capacity of Georgia in 2021 was 4,533 MW. This comprised hydropower (3,323 MW), combined cycle and coal thermal power plants (1,079 MW), natural gas (110 MW) and wind power (21 MW) (Figure 1).[7]

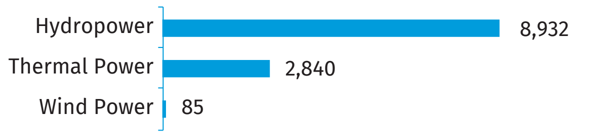
Figure 1. **Installed Electricity Capacity by Source in Georgia in 2021 (MW)**



Source: GSE[7]

In 2019, total electricity generation reached 11,856.8 GWh, over 75 per cent of which was provided by 93 hydropower plants. Seven of these plants were regulatory, providing 56 per cent of all generation from hydropower and 42 per cent of total generation. Nineteen hydropower plants operate on a seasonal basis, contributing approximately 28 per cent of total generation, while 67 deregulated hydropower plants contributed approximately 6 per cent. The remaining electricity was provided by four thermal power plants and one gas turbine (24 per cent of total generation) and one wind power plant (0.7 per cent of total generation) (Figure 2).[8] Imports of electricity in 2019 equalled 1,626.5 GWh, 68 per cent of which came from Azerbaijan and 32 per cent from Russia.[8]

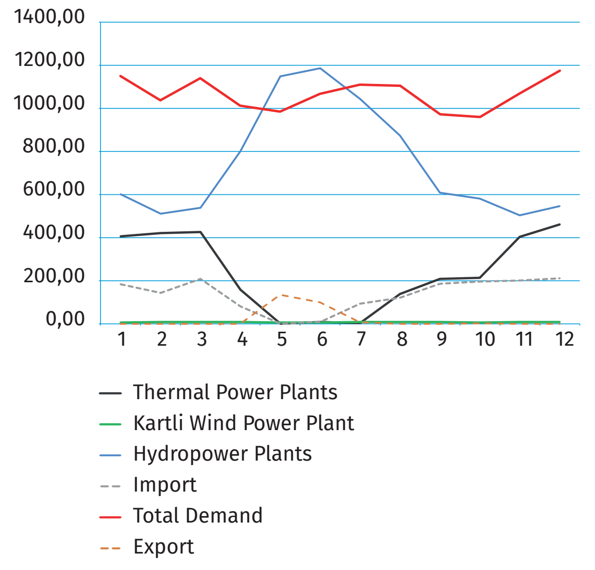
Figure 2. **Annual Electricity Generation by Source in Georgia in 2019 (GWh)**



Source: ESCO[8]

Electricity consumption in 2019 reached 13,144.7 GWh.[8] Due to fluctuations in precipitation, which affect hydropower generation, Georgia is both an importer and exporter of electricity. From May to June 2019, hydropower alone not only satisfied domestic demand but also supported the export of 234.3 GWh of electricity. However, outside of the May–June period, available capacity was not able to meet peak demand and nearly half of the total electricity supply came from thermal power plants and imports (Figure 3).[8] Currently Georgia is a net importer of natural gas and petroleum products, which, together with hydropower and biomass for residential heating, are the main energy sources. Access to electricity in Georgia is 100 per cent.[9]

Figure 3. **Electricity Balance in Georgia in 2019 (GWh)**



Source: ESCO[8]

Georgia has significantly liberalized the electricity market and implemented legislative revisions that have allowed the private sector to largely take over operations via privatization. Four key state institutions operate in the Georgian electricity sector. The Ministry of Energy is the policymaker responsible for the development and implementation of energy policy, environmental safety, the creation of a competitive environment through efficient market regulation, approval of annual energy balances and participation in the approval of strategic projects. In December 2017, the Ministry of Energy was officially merged with the Ministry of Economy and Sustainable Development. Therefore, the Ministry of Economy and Sustainable Development became the legal successor of the former.[10]`The Georgian National Energy and Water Supply Regulatory Commission (GNEWSRC) is the independent regulatory body whose main functions include: licensing in the energy sector, setting and regulation of tariffs (including for generation, transmission, dispatch and distribution), monitoring of the quality of services provided by licence holders and dispute resolution. The GNEWSRC is also authorized to impose sanctions for regulatory breaches.[11]

The Electricity System Commercial Operator (ESCO) is the commercial operator responsible for balancing the market, ensuring grid stability, conducting export/import operations to meet systemic and emergency demand and managing a unified database of wholesale energy purchase and sale (including the creation and management of a unified reporting registry). According to the Electricity Market Rules, licensed suppliers of electricity and any direct (eligible) consumers of electric power (currently some of the largest wholesale consumers) may enter into short- or long-term direct contracts for the sale and purchase of electricity. ESCO, while balancing the market (i.e., taking away surplus and filling the deficit at any particular moment), is eligible to trade non-contracted electricity and guaranteed capacity based on market-defined pricing mechanisms. It supplies dispatch licensees with the information required to carry out supply and plan consumption.[12]

Finally, the Georgian State Electrosystem (GSE) is the owner and operator of the transmission system and the sole dispatch licensee. Its main function is technical control and supervision over the entire electric system to ensure an uninterrupted and reliable electricity supply. It only has the right to purchase electricity to cover transmission losses. GSE also owns and operates part of the high-voltage transmission grid and interconnection lines with neighbouring countries.[13] Two distribution companies provide most of the retail sales: Telasi JSC, covering the region in and near Tbilisi; and Energo-Pro Georgia JSC, covering Central and Western Georgia and the eastern part of Georgia, excluding the regions of South Ossetia and Abkhazia.

Georgian legislation allows retail consumers totalling above 7 GWh in annual electricity purchases to negotiate agreements with electricity producers and importers. There are six qualified retail consumers and each purchases electricity directly from electricity producers.

As of January 2021, tariffs (exclusive of VAT) for selling electricity generated by regulated hydropower producers in Georgia varied widely, between 0.004 USD/kWh (0.013 GEL/kWh) for the Vartsikhe-2005 LTD and 0.031 USD/kWh (0.106 GEL/kWh) for the Khrami 2 hydropower plant. For thermal power plants, tariffs (exclusive of VAT) varied between 0.030 USD/kWh (0.103 GEL/kWh) and 0.046 USD/kWh (0.157 GEL/kWh) as of March 2021.[14] Newer plants generally receive a higher tariff than older ones. Enguri and Vardnili are the largest state-owned hydropower plants, generating on average 34 per cent of total electricity generation and 45 per cent of hydropower generation. The guaranteed capacity payments are collected by ESCO from all consumers and exporters in proportion to their consumption or export. Electricity consumption tariffs for the subscribers of Telasi JSC and Energo-Pro Georgia are shown in Table 1.

Table 1. **Electricity Consumption Tariffs in Georgia in 2021**

	Telasi tariff inclusive of VAT	*Energo-Pro tariff inclusive of VAT*
	By voltage level	
220/380 V (non-residential)	0.329 GEL/kWh (0.085 USD/kWh)	0.320 GEL/kWh (0.097 USD/kWh)
3.3-6 – 10 kV	0.296 GEL/kWh (0.076 USD/kWh)	0.309 GEL/kWh (0.094 USD/kWh)
35 – 110 kV	0.274 GEL/kWh (0.07 USD/kWh)	0.283 GEL/kWh (0.086 USD/kWh)
	By consumption level	
< 101 kWh	0.180 GEL/kWh (0.046 USD/kWh)	0.177 GEL/kWh (0.054 USD/kWh)
101 – 301 kWh	0.221 GEL/kWh (0.057 USD/kWh)	0.217 GEL/kWh (0.066 USD/kWh)
> 301 kWh	0.265 GEL/kWh (0.068 USD/kWh)	0.262 GEL/kWh (0.079 USD/kWh)

Source: Energo-Pro Georgia JSC,[15] Telasi JSC[16]

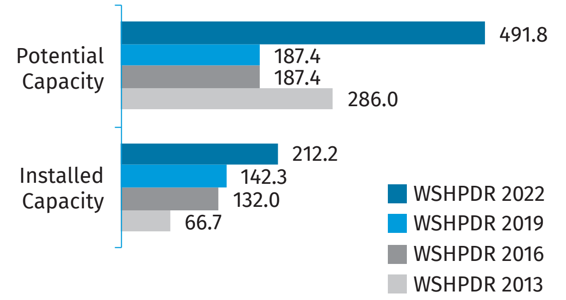
The main objective of the Government's energy policy is to improve the country's energy security. Other objectives include the diversification of energy sources, optimal utilization of local resources including renewable energy, increase of the compatibility of the country's legislative and regulatory framework with that of the European Union (EU) and the development of an energy market and an improved energy trading mechanism. Additionally, the energy policy aims to strengthen the role of Georgia as a regional energy transit point and platform for clean energy generation and trade and will be pursued through an integrated approach to energy efficiency, taking into consideration environmental issues and protection of consumer interests. The main focus of the long-term energy policy is to attract foreign investment for the construction of new power plants. Given the potential for high-capacity electricity generation and the increasing energy demand, an additional long-term objective is the construction and rehabilitation of connecting infrastructure that would enable export of surplus power to neighbouring countries.[17,18]

The Georgian electricity sector has faced many changes in recent years. In 2017, the Minister of Energy signed the protocol of the country's accession to the Energy Community Treaty, thus, signalling readiness to implement a reform of the energy trading system and develop competitive energy markets. The signing of the Treaty triggered legislative changes aimed at harmonizing with the EU market. In December 2019, the Georgian Parliament approved the Law of Energy and Water Supply, which describes in detail the functioning of the energy market.[17] On 16 April 2020, the Electricity Market Concept Design was approved, which takes into account the stages of market opening and the basic principles of the transition process. In accordance with the Concept, a Day-Ahead Market (DAM)/Intra-Day Market (IDM) operator, as well as a Balancing Market (BM) operator was formed in the wholesale segment. The Georgian National Energy and Water Regulatory Commission (GNERC) approved rules for both of these markets. The reform is intended to develop a market guided by the EU internal market principles: competition, transparency, non-discrimination and sustainability.[19,20]

SMALL HYDROPOWER SECTOR OVERVIEW

According to the Law on Energy and Water Supply of 2019, small hydropower (SHP) in Georgia is defined as hydropower plants with an installed capacity of less than 15 MW. These are termed deregulated plants on the basis that plants with an installed capacity of less than 15 MW have the right to operate without a licence, requiring only a construction permit and an environmental permit and sell generated electricity directly to consumers.[21]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Georgia (MW)**



Source: *WSHPDR 2016*,[6] GSE,[7] *WSHPDR 2013*,[22] *WSHPDR 2019*[23]

Note: Data for SHP up to 10 MW.

As of 2021, the total installed capacity of SHP plants of less than 15 MW was 262.98 MW, 212.18 MW of which was from plants of up to 10 MW.[7] Based on the feasibility studies carried out for ongoing and planned SHP projects, the total known potential capacity of SHP in Georgia (including currently installed capacity) is estimated at 491.78 MW for plants of less than 10 MW capacity and 723.88 MW for plants of less than 15 MW.[7] These data suggest that approximately 36 per cent of the known SHP potential for plants of less than 15 MW and 43 per cent of the SHP potential for plants of less than 10 MW has been developed. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP up to 10 MW increased due to the commissioning of new plants and the potential capacity increased based on new data made available (Figure 4).

In 2019, there were 67 SHP plants (less than 13 MW as per the old definition) in operation, all of which were privately owned and many of them in need of refurbishment. In 2019, they generated approximately 655 GWh of electricity, accounting for 13 per cent of total hydropower generation for that year.[8] As of early 2021, there were 72 SHP plants in operation in Georgia, based on the new definition of SHP of up to 15 MW, of which 68 were under 10 MW.[7] The most recently commissioned SHP plants are shown in Table 1.

Table 1. **List of Selected Recently Commissioned Small Hydropower Plants in Georgia**

Name	*Installed capacity (MW)*	*Number of units*	*Type*	*Launch year*
Maksania	0.5	-	Run-of-river	2017
Nabeglavi	2.0	2x1	Run-of-river	2017
Kintrisha	5.5	2x2.75	Run-of-river	2017
Shilda 1	1.2	1x1.2	Run-of-river	2018
Kasleti 2	9.1	2x4.55	Run-of-river	2018
Kheor	1.5	1x1.48	Run-of-river	2018
Bodorna	2.5	1x2.5	Run-of-river	2018
Jonouli 1	1.9	1x1.85	Run-of-river	2018
Skurididi	1.3	1x1.33	Run-of-river	2018
Aragvi 2	2.0	1x1.95	Run-of-river	2019
Oro (Zemo orozman)	1.1	1x1.12	Run-of-river	2019
Avani	3.5	2x1.75	Run-of-river	2019
Sashuala 2	5.0	1x5	Run-of-river	2020
Ifari	3.0	2x1.49	Run-of-river	2020
Khelra	3.4	2x1.69	Run-of-river	2020
Dzama	0.8	2x0.41	Run-of-river	2020
Lakhami 2	9.5		Run-of-river	2020
Skhalta 1	9.0		Run-of-river	2020
Sashuala 1	7.5		Run-of-river	2020
Lakhami 1	6.4		Run-of-river	2020

Source: GSE[7]

Note: The plants Lakhami 1, Skhalta and Sashuala 1 listed in the source as planned had been commissioned and were operational as of early 2021.

Furthermore, 27 SHP projects (up to 10 MW) with a combined installed capacity of 114.55 MW were in the licensing and construction phase as of December 2020 (Table 2) and a further 47 projects with a combined capacity of 173.53 MW were in the feasibility study stage.[7]

Table 2. **List of Selected Ongoing Small Hydropower Projects in Georgia in 2020**

Name	*Estimated installed capacity (MW)*	*Estimated annual generation (GWh)*	*Plant type*	*Developer*	*Development stage*
Nakra	7.50	35.20	Run-of-river	LLC Aquahydro	Licensing and construction
Lopota 1	5.90	33.40	Run-of-river	LLC Artana Lopota	Licensing and construction
Khadori 3	5.40	27.50	Run-of-river	LLC Alazani Energy	Licensing and construction
Sam-kurists-kali 1	4.80	25.70	Run-of-river	LLC Feri	Licensing and construction
Rachkha	3.03	11.46	Run-of-river	LLC GN Electric	Licensing and construction

Source: GSE[7]

RENEWABLE ENERGY POLICY

In 2013, the Government of Georgia set forth a legislative initiative (Resolution of Government of Georgia No. 214 of 21 August 2013) in order to facilitate sustainable development of the country's renewable energy potential. This initiative regulates procedures and rules of expression of interest for construction, ownership and operation of power plants in Georgia.[24]

The Energy Reforms and International Relations Department of the Ministry of Economy and Sustainable Development of Georgia is actively working on the development of the country's energy efficiency and renewable energy policy in collaboration with the European Bank for Reconstruction and Development (EBRD), the Energy Community Secretariat (EU4Energy programme), the Government of Denmark (DENEP II), KfW and other donor organizations. In 2016, the National Action Plan for the Implementation of the Association Agreement between Georgia on the one hand and the EU and the European Atomic Energy Community and their Member States on the other, as well as the Association Agenda between Georgia and the EU, were approved by Decree No. 382 of the Government of Georgia of 7 March 2016.[25]

According to the Decision of the Ministerial Council of the Energy Community (Decision 2016/18/MC-Enc), in October 2016 Georgia accessed the Energy Community as a Contracting Party. The Treaty means that the Government of Georgia has committed to implement the relevant EU rules on energy, environment and competition.[23,25]

With the joint effort of the Government of Georgia and the relevant EU authorities (EU Commission, EBRD, Energy Community Secretariat, etc.), the relevant legislative framework encapsulating three key laws (Law on Energy Efficiency, Law on Energy Efficiency of Buildings, Law on Energy Labelling) has been developed, based on the EU Energy Efficiency acquis. In December 2019, the Government of Georgia approved the National Energy Efficiency Action plan 2019–2020 (NEEAP), intended to implement the core principles of the EU energy efficiency legislation and reflecting the legislative framework developed at earlier stages.[21] In 2020, the Eastern European Energy Efficiency and Environment Partnership (E5P) Contributors Assembly approved EUR 2.6 million (USD 3.1 million) in grants in order to support project implementation in Georgia by the Nordic Environment Finance Corporation (NEFCO), which refers to energy efficiency improvement in public schools in mountainous regions of the country.[26]

In 2010, 16 Georgian municipalities joined the EU initiative Covenant of Mayors, committing to reduce CO_2 emissions by 20 per cent by 2020. A total of 24 Georgian cities are signatories of the Covenant of Mayors and are participating in the programme. Ten cities have developed Sustainable Energy Action Plans (SEAPs) defining various energy efficiency and renewable energy measures for the priority sectors: transport, infrastructure, building, street lighting, land-use changes and waste management. The major provisions of the SEAPs include support for renewable energy utilization at a local level, development of heating and cooling of public buildings based on renewable energy sources, development of electric public transport and introduction of solar photovoltaic (PV) systems for streets.[27]

The latest amendments of the Law on Electricity and Natural Gas of Georgia encourage the purchase and construction of micro-power plants (up to 500 kW). The customers will have a possibility to generate electricity, use it and sell the surplus to the grid at the cost established by GNERC.[28]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The regulations of the Georgian hydropower sector offer potential investors many advantages. Newly built hydropower plants remain the exclusive property of investors through a Build–Operate–Own (BOO) scheme. The electricity generated by SHP plants with capacity up to 15 MW may be used by the developer for their own needs. If it is possible to connect to the local grid, the produced electricity may be exported via the local distribution network based on an agreement with ESCO or with the local distribution companies that deliver electricity directly to the client. It is nearly always financially advantageous to consume as much of electricity as possible on site and only export the surplus into the network. Between 1 September and 1 May each year, within the scope of a direct agreement made in compliance with standard conditions, the highest tariff is based on the thermal power plant electricity sold to ESCO. In the same period, the adjustable fixed tariff based on hydropower is the lowest tariff established by GNERC. Small capacity power plants may purchase electricity for the purpose of ensuring the relevant execution of the agreement on electricity generated by such plants; however, the volumes should not exceed the framework of the forecasted electricity volumes proposed (capacity).[21]

If SHP plants produce electricity for export to the local network, early discussions with the local distribution companies are needed to specify the system protection, metering equipment and the technical requirements. They will also provide an estimate of connection costs and the best location to connect to their system.[21]

The development of hydropower plants, including SHP, is regulated by the following legislation:

- Law of public and private collaboration (the public-private partnership law) of 1 July 2018 and the Government's Resolution No. 426 of August 2018 on public and private collaboration in project development and implementation. These pieces of legislation enable a company to request a guaranteed electricity purchasing tariff through a power purchase agreement.[29]
- The Government's Resolution No. 515 of 31 October 2018 on renewable energy power plants' techno-economic studies, construction, ownership and operation. The resolution is specifically focused on regulating renewable energy projects that are not launched under the public-private collaboration framework and many have already been submitted to the Ministry of Economy and Sustainable Development under Resolution No. 515 following its adoption.[30]
- The Government's Resolution No. 403 of 2 July 2020 on the support schemes for production and usage of energy from renewable resources, including hydropower. The resolution applies only to hydropower plants of more than 5 MW capacity and provides regulations defining the support period and conditions for the disbursement of a bonus tariff[31]
- The Government's Resolution No. 257 of 31 May 2019, which defines the procedure for issuing permits for the construction of facilities of special importance and the permit conditions.[32]
- The Government's Resolution No. 890-IIs of 1 June 2017, which defines the Environmental Assessment Code. According to this resolution, SHP plants of up to 2 MW capacity are exempt from undergoing an environmental impact assessment (EIA).[33]

During the licensing stage, the project is initially submitted to the Ministry of Energy and Sustainable Development, where it is reviewed by the Department of Energy Policy and Investment Projects, which prepares a report card for the Deputy Minister. At this point the preparation of the contract for the project begins with the decision and assignment of the Deputy Minister. Subsequently, the prepared draft contract is sent to the Ministry of Justice, the Ministry of Finance and the Public and Private Partnership Agency. Following discussions, the Government issues an ordinance and a contract is signed based on that ordinance.

Initiating construction is possible prior to receiving the licence and is referred to as the construction-licensing stage. Construction permits are issued by the Technical and Construction Supervising Agency (TACSA, part of the Ministry of Energy and Sustainable Development) and regulated by Resolution No. 257.[32,34]

COST OF SMALL HYDROPOWER DEVELOPMENT

The cost of construction of SHP plants in Georgia per MW ranges from USD 1 million to USD 2 million. The reference tariff is approximately USD 0.055 per 1 kWh of generation. The payback period also varies from project to project and is generally between 6 and 10 years. A detailed study on the cost of SHP development in Georgia was carried out in 2015 by the Norwegian Water Resources and Energy Directorate in collaboration with the Ministry of Energy of Georgia. The study prepared price curves for SHP plants of several common turbine types (including Pelton, Francis and Kaplan/bulb turbines) and for capacities of 1–13,000 kW. According to the study, typical prices ranged between approximately USD 1,520 and USD 4,738 per kW for low-head (5–20 metres) installations and between USD 275 and USD 870 per kW for high-head (100–600 metres) installations.[35] Estimates of investment costs of some SHP projects are shown in Table 3.

Table 3. **Estimates of Investment Costs of Small Hydropower Projects in Georgia**

Name	*Installed capacity (MW)*	*Estimated investment cost (USD)*	*Developer*
Samkuristskali 1	4.8	6,500,000	LLC Feri
Lakhami 2	9.5	14,790,000	LLC Austrian Georgian Development
Nakra	7.5	9,600,000	LLC Aquahydro
Lopota 1	5.9	8,200,000	LLC Artana Lopota
Khadori 3	5.4	6,200,000	LLC Alazani Energy
Goginauri	4.7	1,300,000	LLC ALTER ENERGY
Rachkha	3.0	13,612,290	LLC GN Electric
Dvirula	2.0	2,620,000	LLC DM Energy
Khrami	1.1	1,100,000	LLC New Technology 2014
Tbilisi sea	0.6	630,000	LLC Aqua Energy Georgia

Source: GSE[7]

Most of the financing of SHP projects is done by commercial banks, based on the principle of 30 per cent equity/70 per cent loan. There are also projects fully funded by foreign organizations and foundations.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The impact of the climate crisis on SHP in particular has not yet been investigated in Georgia. The latest national communications of Georgia were focused on the impacts of the climate crisis on large hydropower plants (such as the Enguri plant). According to the Third National Communication (NC3) of Georgia on Climate Change, average annual temperature in the Upper Svaneti region, which includes the upper part of the Enguri River basin, is expected to increase by 3.7 °C by 2100 compared to the average for the period 1986–2010. The temperature increase is in turn expected to impact the geometrical dimensions of glaciers as well as the glacial runoff in the Enguri River basin. At the current pace of temperature increase, the entire Caucasus Range is expected to be free of ice cover by 2150–2160. The NC3 projects that glacial degradation in the Enguri River basin will lead to a 40 per cent decrease in glacial runoff by 2100, relative to 2010, and a corresponding 13 per cent decrease in annual runoff in the Enguri River itself by 2100, relative to the levels recorded during the mid-20th century.[36]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key barriers to SHP development in Georgia include:
- High initial costs;
- Lack of continually renewed hydrological information;
- Absence of local manufacturing capacity in Georgia, with the exception of a few workshops producing cross-flow (Banki) turbines;
- Lack of financial incentives from international organizations and local banks;
- Lack of tax initiatives or feed-in tariff regimes;
- Cancellation of promising policies, such as concluding long-term power purchase agreements with renewable energy producers;
- Possible decrease in overall hydropower potential in the long-term due to the ongoing climate crisis.[21,29]

The key enabler for SHP development in Georgia is the opening of the electricity market, which will allow generation units operating in Georgia to bid on the DAM/IDM/BM and increase their income, as well as set the real price for electricity in the country. Transparency in pricing is also expected to attract investments. Due to the low marginal cost of electricity for SHP plants, they will be able to recoup their costs quickly and become profitable. Other significant benefits from the new market model are expected to occur:
- Improved system reliability due to provision of sufficient notice for plants to be scheduled;
- Encouragement of the participation of new market players;
- Creation of an arbitrage opportunity between the DAM and the BM, increasing liquidity.

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Iraq

Sameer Saadoon Algburi and Sarmad Nozad Mahmood, Al-Kitab University; and Danila Podobed, International Center on Small Hydro Power (ICSHP)

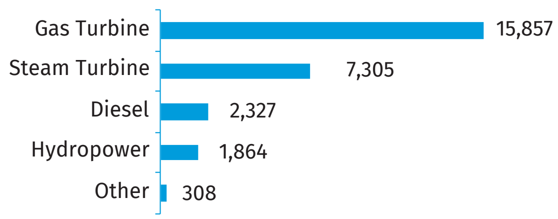
KEY FACTS

Population	40,222,503 (2020)[1]
Area	437,072 km^2[2]
Topography	Iraq has four topographical regions: the alluvial plains in the centre and south-east covering almost one third of the country and characterized by low elevations (below 100 metres); an upland region in the north between the Tigris and Euphrates Rivers with the highest peak reaching 1,356 metres; deserts in the west and south rising to elevations above 490 metres; and the highlands in the north-east with an average elevation of 2,400 metres. The highest point, Ghundah Zhur, lies near the border with Iran border and reaches 3,607 metres.[3]
Climate	The climate of Iraq is hot and dry and is impacted by the country's position between the subtropical aridity of the Arabian Desert and the subtropical humidity of the Persian Gulf. The coldest month is January, with temperatures ranging from 5 °C to 10 °C, while the warmest month is August, with temperatures reaching 30°C and higher. Summers in most parts of the country are mild to hot, with abundant sunshine, but heavy humidity predominates around the southern coast on the Persian Gulf. Summer temperatures can easily reach 45 °C or more, particularly in desert areas. Hot, dry desert winds may be quite powerful at times, causing violent sandstorms.[4]
Climate Change	Expected climate change impacts in Iraq include an increase in maximum temperatures of 0.5–2.5 °C and an increase in minimum temperatures of 0.2–1.8 °C across the country by the end of the 21st century, relative to the 1979–2018 baseline period. The hot arid desert climatic zone predominating in much of the country is expected to shift further northwards by 2071–2090, displacing large areas of the Iraqi arid steppe.[5,6]
Rain Pattern	Average annual precipitation in the lowlands ranges between 100 mm and 180 mm, with most of the rainfall occurring between November and April. In the foothills of the north-east, annual precipitation ranges from 300 mm to 560 mm, while in the mountains it can exceed 1,000 mm, mainly in the form of snow.[3]
Hydrology	The three major river basins in Iraq are the Tigris, the Euphrates and the Shatt Al-Arab. The average annual flow of the Euphrates River at the Iraqi border is estimated at 30 km^3, whereas that of the Tigris River is estimated at 21.2 km^3. While the Tigris receives 50 per cent of its water from the territory of Iraq, the Euphrates receives more than 90 per cent of its water from outside the country. The Tigris has a number of tributaries on its left bank, including the Greater Zab, the Lesser Zab, the Al-Adhaim and the Diyala Rivers. The rivers of Iraq have a total length of 4,773 kilometres, with the Tigris and Euphrates accounting for 1,290 kilometres and 1,015 kilometres, respectively.[7]

ELECTRICITY SECTOR OVERVIEW

The total installed electricity capacity of Iraq operated by the Ministry of Electricity (MOE) in 2019 was 27,661 MW. This total included 15,857 MW (57 per cent) provided by gas-fired power plants, 7,305 MW (26 per cent) provided by steam power plants, 2,327 MW (8 per cent) provided by diesel-fired power plants, 1,864 MW (7 per cent) provided by hydropower plants, and 308 MW (1 per cent) provided by other sources (Figure 1). However, not all existing plants were operational as of 2019, with available capacity at 22,031 MW. Additionally, average daily power output that year was only 14,064 MW due to issues with operational efficiency in the electricity sector also observed in previous years.[8,9]

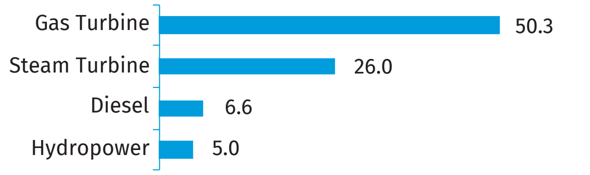
Figure 1. **Installed Electricity Capacity by Source in Iraq in 2019 (MW)**



Source: MOE[8]

Generation of electricity by power plants operated by the MOE in 2019 reached 87.9 TWh, with gas-fired power plants providing 50.3 TWh (57 per cent) of the total, steam power plants providing 26.0 TWh (30 per cent), diesel power plants providing 6.6 TWh (nearly 8 per cent) and hydropower providing 5.0 TWh (6 per cent) (Figure 2). Purchases of electricity from independent power producers (IPPs) amounted to 27.8 TWh, imports from neighbouring countries were 6.6 TWh and another 0.9 TWh were imported from the autonomous Kurdistan Region.[8]

Figure 2. **Annual Electricity Generation by Source in Iraq in 2019 (TWh)**



Source: MOE[8]

Electricity supplied to the grid in 2019 totalled 108.8 TWh, but losses accounted for 66.8 TWh (61 per cent) of the total supply, with only 42.0 TWh billed to customers. Consumption was dominated by the residential sector, which used 25.8 TWh or 61 per cent of all billed consumption, while the government sector consumed 5.2 TWh (12 per cent), the industrial sector consumed 4.7 TWh (11 per cent) and the remainder was accounted for by the commercial sector, the agricultural sector and other consumers.[8] As of 2020, access to electricity in Iraq was 100 per cent.[10]

Electricity shortages in Iraq entail major costs for the economy in the form of lost production time, damage to capital assets from power interruption and disruption of commercial processes. It is estimated that shortages of electricity cost the country's economy some USD 3–4 billion per year.[11] Furthermore, due to cold winters and extremely hot summers, power shortages also impose significant hardship on the population.

The two main providers of electricity in Iraq are the MOE and private owners of generators scattered across the country. The MOE is the principal policy maker, power producer, service provider, regulator and operator of the electricity sector in Iraq. As a result of inefficient policies, a lack of security, the burden of the military campaign against the Islamic State and the decline of oil prices, the electricity sector has been falling into decay, leading to the failure of the MOE to supply electricity 24 hours a day across the country. The unreliable power supply from the national grid has led to the widespread installation of private diesel generators and the creation of neighbourhood mini-grids. These are not regulated by the Government and their constant operation implies significant costs, as well as noise, air pollution and carbon emissions. In addition, international oil companies operating in the country constitute a third limited producer of electricity, but they produce electricity for their own use only. Generally, they are also not subject to Government regulations.[11]
In addition to the issues on the supply side of the electricity sector, challenges also exist on the demand side. These include the widespread theft of electricity, resulting in high levels of unmetered consumption and widespread non- or under-collection of bills due to the absence of an effective billing system.[11] In recognition of the need for a reform, the Government began the privatization of the electricity sector in early 2016. A multi-phase strategy was developed in consultation with the World Bank, which aims to reform the distribution sector, reduce electricity consumption by 20 per cent, curb losses and end the exploitation of consumers by the owners of neighbourhood grids. Based on the recommendations of the World Bank, the country was divided into 180 zones. Private companies will take over responsibility for distribution in each zone and ensure around-the-clock electricity supply in return for a percentage of electricity tariffs. The first projects were launched in 2016 and 2017 in Baghdad neighbourhoods and have produced positive initial results.[11]

Apart from the MOE capacities and neighborhood mini-grids, the country imports electricity from Iran via four transmission lines providing access to a combined capacity of 1,100 MW. Furthermore, the MOE purchases power from several large domestic IPPs located in the cities of Samawa, Basra and Basmaya with a total installed capacity of 470 MW, as well as from the Bazian power plant in the Kurdistan Region with a capacity of 3,120 MW as of 2021 (set to be increased to 4,500 MW). Plans exist to develop additional interconnections with Turkey and the countries of the Gulf Cooperation Council, as well as to construct several large solar power plants in southern Iraq with a total capacity of 755 MW.[12]

Electricity tariffs in Iraq for electricity purchased from the national grid are determined by consumer category, as well as by consumption category in the case of the residential and commercial sectors. While the cost of electricity production in the country was 108 IQD/kWh (0.091 USD/kWh) in 2017, electricity tariffs for end users are heavily subsidized, to over 90 per cent of the production cost.[11] Electricity tariffs current as of 2019 are displayed in Table 1.

In practice the subsidized electricity provided by the MOE is not sufficient to meet electricity demand and many people rely on purchasing additional expensive power from neighbourhood generators. The cost of a 1-ampere generator connection is 7–20 USD/month depending on the length of the daily service time, or approximately 125 IQD/kWh (0.086 USD/kWh) in the case of a 24-hour connection, with a typical family spending upwards of 300 USD/month for a 15-ampere connection. Neighbourhood generators were estimated to have generated USD 4 billion in income in 2018, or roughly the same as the capital expenditures for the entire power sector set aside in the 2019 federal budget.[12]

Table 1. **Electricity Tariffs in Iraq in 2019**

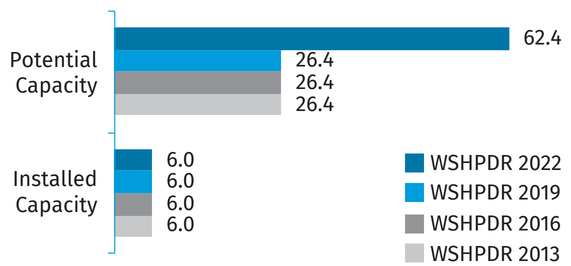
Consumption category	*Price in IQD/kWh (USD/kWh)*
Residential:	
1–1,500 kWh	10 (0.007)
1,501–3,000 kWh	35 (0.024)
3,001–4,000 kWh	80 (0.055)
≥ 4,001 kWh	120 (0.083)
Commercial:	
1–1,000 kWh	60 (0.041)
1,001–2,000 kWh	80 (0.055)
≥ 2,001 kWh	120 (0.083)
Industrial	60 (0.041)
Governmental	120 (0.083)
Agricultural	60 (0.041)

Source: MOE[8]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in Iraq. In the current chapter, SHP is defined as hydropower plants with a capacity of up to 10 MW. The installed capacity of SHP in Iraq as of 2019 was 6 MW, whereas the hydropower potential, including existing plants and potential sites, is estimated at 62.38 MW, indicating that approximately 10 per cent of the known potential capacity has been developed. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP in Iraq has not changed, whereas the total potential capacity has increased 136 per cent due to a reassessment of existing data (Figure 3).[9,13,14]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Iraq (MW)**



Source: *WSHPDR 2019*,[9] Al-Kayiem & Mohammad,[13] Ameen,[14] *WSHPDR 2013*,[15] *WSHPDR 2016*[16]

Although there is no official definition of SHP in Iraq, hydropower plants with a capacity of up to 80 MW are generally classified as SHP plants. Following this definition, there are six SHP plants in the country, of which only one is below 10 MW (Table 2). The combined capacity of hydropower plants up to 80 MW is 251 MW.[14]

Table 2. **Existing Hydropower Plants up to 80 MW in Iraq**

Name	*Capacity (MW)*
Samaraa Dam	80
Mosul Regulating Dam	60
Hemrin Dam	50
Adhaim Dam	40
Al-Hindiyah Dam	15
Shatt Al-Kuffa Regulator	6
Total	*251*

Source: Ameen[14]

Total hydropower potential in Iraq is estimated to be 80,000 GWh.[9] The potential SHP capacity estimate is based on previous studies that have identified 49 prospective hydropower sites with potential capacities ranging from 5 MW to 261 MW, of which six were SHP sites within the 5–10 MW range, suggesting a minimum total potential capacity of 30 MW for these six plants (Table 3).[9,14] Besides the identified potential sites, there are also 30 non-powered barrages and water regulators that can be used for electricity generation, of which at least 12 can be used for SHP development. Their combined capacity is 26.38 MW (Table 4).[9,14]

Table 3. **Potential Hydropower Sites in Iraq by Capacity Range**

Installed capacity (MW)	*Number of sites*
5–10	6
11–20	7
21–30	5
31–50	12
51–100	12
101–150	6
> 150	1

Source: Ameen[14]

Table 4. **Potential Small Hydropower Sites in Iraq on Existing Infrastructure**

Site	*Units*	*Discharge (m^3/s)*	*Potential capacity (MW)*
Tarthar Water	4	171	5.662
Al-Abbasiya Regulator	2	168	4.683
Al-Garraf Head Regulator	4	158	3.650
Al-Btera Regulator	2	118	3.016
Al-Hilla Head Regulator	8	189	2.634
Al-Kahla Regulator	2	67	2.394

Site	*Units*	*Discharge (m^3/s)*	*Potential capacity (MW)*
Al-Sader Al-Mushtarak	3	60	1.300
Al-Khalis Regulator	1	49	0.760
Al-Diwaniya Regulator	3	49	0.755
Al-Kassara Regulator	1	24	0.601
Al-Dagara Regulator	2	31	0.508
Qal'at Salih Regulator	2	25	0.416
Total	**34**	**–**	**26.379**

Source: Ameen[14]

Since 2013, Iraq neither added nor announced additional new hydropower capacities. As such, the development of hydropower, including SHP, currently does not represent a major priority for the country's energy sector development, and it is not expected that many hydropower plants will be built in the future.

RENEWABLE ENERGY POLICY

Iraq is one of the world's most important oil producers and is among the countries with the largest proven oil reserves. Over the past years, the energy sector of Iraq has suffered due to the war and energy demand growth is now outpacing capacity expansion. Renewable energy could be used to both supply electricity to remote locations not connected to the grid and to feed into the grid. This aim was outlined in the Integrated National Energy Strategy of Iraq of 2012, which remains the country's sole policy document targeting renewable energy development.[17]

However, the development of renewable energy sources has been progressing rather slowly, hindered by the conflict with the Islamic State and other systemic factors.[17] Thus it was only in 2016 that the MOE opened the first renewable energy tender for the 50 MW Sawa solar power project in Al-Salman District.[18] The installation of solar photovoltaic (PV) panels by households has likewise made little progress in the country, in spite of the severe energy shortage in the past decade. This is due to the high installation costs for solar power compared to those for diesel generators, with the latter at just 5 per cent of the cost of installation for a solar PV system of comparable capacity.[19]

There are no further policies on renewable energy or energy efficiency. The Government is aiming to attract new foreign investors for solar and wind power projects, offering various tax exemptions and support during the licensing, approval, implementation and operation processes.[20] However, there are no universal incentives in place applicable to all renewable energy projects.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The following factors entail major barriers to the development of SHP in Iraq:
- Lack of financial resources;
- The poor condition of electricity infrastructure;
- Constantly changing plans of the Government, including frequently cancelled tenders;
- Risks associated with payments and security.

There are few, if any, enablers for further SHP development in Iraq; however, some untapped potential SHP capacity exists in the country in the form of both new sites as well as existing non-powered barrages and dams.

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Israel

Grant Pace, Chi Chen and Stafford W. Sheehan, Air Company

KEY FACTS

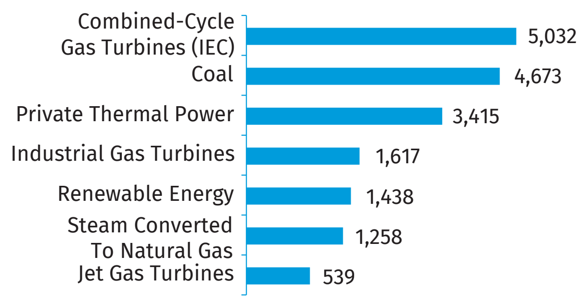
Population	9,054,000 (2019)[1]
Area	20,770 km[2]
Topography	Located within the Fertile Crescent region, Israel hosts a variety of topological features, including highlands, river valleys, Mediterranean coasts, mountains, coastal plains and deserts. At 1,208 metres, Mount Meron is the highest point in the country. Israel also features the Dead Sea, which is the lowest point on the Earth's continental surface (400 metres below sea level).[2]
Climate	Due to its diverse topography, including deserts and coasts, Israel has various climates. The coastal areas have a typical Mediterranean climate with cool, rainy winters and long, hot summers. By contrast, the southern Negev and Arava areas have hotter desert climates with milder winters and little precipitation.[2,3] Temperatures across these regions range from 11 °C in January on the Mediterranean coast to 46 °C in August in the southern City of Elat.[2] The capital, Jerusalem, is representative of the hot summer Mediterranean climate that dominates most of the country and has an average temperature of 17.2 °C.[4]
Climate Change	Due to climate change, Israel has seen an increase in the number of incidents of extreme heat waves and experiences 10 mm of sea level rise annually. By 2100, a 10 per cent decrease in precipitation is projected.[5]
Rain Pattern	Israel receives roughly 70 per cent of its rainfall between November and March, with almost no rain from June to August. Precipitation decreases with latitude: the south receives less than 100 mm of rain annually and the north receives approximately 1,100 mm of precipitation.[6]
Hydrology	The Jordan River is the longest and most notable river in Israel, flowing 251 km south through the freshwater Sea of Galilee (Lake Tiberias) and into the Dead Sea.[7] The Sea of Galilee in the north-east is the largest freshwater lake in the country, covering 166 km[2] and reaching depths up to 43 metres.[8] In the south, the Dead Sea rests at 430 metres below sea level.[9]

ELECTRICITY SECTOR OVERVIEW

In 2020, 100 per cent of the population of Israel had access to the nationalized electricity system.[10] Israel was a net importer of energy in 2019, importing approximately 259,000 GWh and exporting approximately 79,000 GWh.[11] The largest portion of this imported energy came in the form of crude petroleum from Azerbaijan, Kazakhstan and the United States.[12]

At the end of 2018, the installed electricity capacity of Israel totalled 17,972 MW, of which approximately 74 per cent (13,335 MW) was operated by the predominantly state-owned Israel Electric Corporation (IEC). Private generators, including renewable energy plants, accounted for the rest (Figure 1).[13] In 2019, the country's total installed electricity capacity is reported to have reached 19,493 MW.[14]

Figure 1. **Installed Electricity Capacity by Source in Israel in 2018 (MW)**

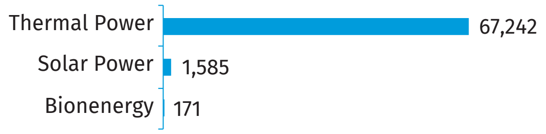


Source: Ministry of Energy[13]

Note: The capacities were calculated based on percentage values.

According to the Central Bureau of Statistics of Israel, in 2019, a total of 9,509 ktoe (110,600 GWh) of energy was produced domestically. The energy supply breakdown primarily consisted of natural gas (90 per cent). Smaller portions came from solar thermal power (4 per cent), solar photovoltaics (PV) (approx. 2 per cent), oil (approx. 1 per cent) incineration of non-renewable (approx. 1 per cent) and renewable waste (0.1 per cent) and other renewable sources (0.1 per cent).[13] Electricity supply totalled 68,998 GWh in 2018, with over 97 per cent coming from fossil fuels and the remainder from renewable energy (Figure 2). Renewable energy sources were dominated by solar power, with an unspecified amount of electricity coming from hydropower.[15] In 2019, domestic electricity generation in the country reached 72,524 GWh; however, no breakdown of generation by source is available.[14]

Figure 2. **Annual Electricity Generation by Source in Israel in 2018 (GWh)**



Source: IRENA[15]

Few annual days of precipitation and high sunshine would make solar power a prominent energy source; however, the success of solar energy has been significantly limited by recent discoveries of abundant offshore natural gas reserves and supply deals with Egypt. Natural gas shifted fossil fuel consumption from 65 per cent of coal and 33 per cent of natural gas in 2009 to 45 per cent of natural gas in just two years. This trend was projected to continue with an over 65 per cent share of natural gas expected by 2020.[16] However, natural gas receded to under 40 per cent of total energy supply by 2019, in part due to the overabundance of natural gas reserves in the country exceeding the demand for exports and internal usage.[11,17,18]

Unconnected to any other electricity grid, Israel is often portrayed as an electricity island. In recent years, Israel began planning pumped-storage hydropower facilities to make use of surplus electricity capacity at off-peak periods. The Israeli Public Utilities Authority has commissioned the Gilboa pumped-storage hydropower plant with a capacity of 300 MW, which is the first plant of this kind in Israel.[19,20] The commissioning of the turbines was scheduled for 2018 and the plant began operating in 2020.[21] As of 2016, a second pumped-storage hydropower plant was planned with a capacity of 340 MW, and in total the Government has a national plan for 800 MW of pumped hydropower capacity.[19] The Dead Sea Water Project, the first sea water pumped-hydropower plant with a capacity of 2,400 MW, is scheduled to be completed in 2021.[22] Additionally, a number of tidal wave projects have been developed or are under development in Jaffa Port near Tel Aviv.[23,24]

The majority of electricity in the country is provided by IEC, one of the largest industrial organizations in Israel and the sole integrated electric utility in the country. Since 2011, IEC has been operating 17 power plants (including five major thermal power plants). In June 2018, the Government approved a comprehensive structural reform in the Israeli electricity sector, to be implemented over the course of eight years (2018–2026), to decentralize IEC. The reform is aiming to lower the market share of IEC to 40–60 per cent in 2026. After the implementation of these policies to promote competition in the sector, in 2018 the share of IEC in the total installed capacity of Israel dropped to 74 per cent.[13] In 2019, IEC represented 72 per cent of the electricity market, with the remaining energy coming from individual power producers (IPPs).[17] These figures demonstrate the rapid growth of the electricity provided by private producers, whose output made up 0.5 per cent of the total supply as recently as 2009.

The Public Utilities Authority for Electricity was established in 1996 to oversee electricity tariffs under the Electricity Sector Law. Prior to the creation of the Authority, IEC itself regulated the electricity market. The Authority sets formulas that determine the rates of the tariffs without an explicit cap. Distinct electricity rates exist for residential and agricultural use, street lighting, general, bulk and time of use, but not across regions.[25] In January 2019, the cost of electricity for household consumers rose by 6 per cent to 0.49 ILS/kWh (0.15 USD/kWh).[25] The tariffs, which are based on the cost of the service, rose due to the cost of pursuing the Government's decision to increase the share of renewable energy sources and the weakening of the shekel against the US dollar, exacerbating rising fuel costs.[18]

SMALL HYDROPOWER SECTOR OVERVIEW

Israel does not have an official definition of small hydropower (SHP). For the purposes of this chapter, SHP will be defined as any hydropower plant with a capacity below 10 MW.

Since 2010, the International Renewable Energy Agency (IRENA) has reported that the capacity of SHP in Israel has been constant at 7 MW, demonstrating the lack of focus to develop SHP in Israel in comparison to other sources of clean energy.[26] This total SHP capacity comes from various unspecified power plants identified by the Israeli Ministry of Environmental Protection report in 2014. However, detailed information on these SHP plants has not been provided by the Ministry or other sources.[27] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the current edition is reporting a higher capacity based on more accurate data (Figure 3), however, as mentioned there has been no actual change in installed capacity. The potential for SHP development in the country remains unknown.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2019/2022 in Israel (MW)**

Source: IRENA,[26] *WSHPDR 2019*[28]

The SHP capacity of Israel has not grown according to official figures, despite discussion of hydropower as a means of energy diversification.[27] Regardless, this endeavour has spurred innovation, including the Benkatina turbine, a damless plant generating hydropower from municipal pipes, which was invented by engineers from Leviathan Energy.[29] Ranging from 5 kW to hundreds of kilowatts, this small turbine fits into existing piped-water systems so that it can generate electricity from the water running downhill through it while maintaining the integrity of the piping. The turbine requires low infrastructural support and is adaptable to variable flow conditions. So far, it has been installed in several locations in Israel since 2013, however, the capacity of these installations is not known. Since 2012, other hydropower technologies have also been introduced in Israel. Thus, in 2020, researchers identified 96 potential sites for closed-loop hydropower plants using geographic information system (GIS) analysis. However, the average generation potential of these sites amounts to 42.7 GWh, which exceeds the 10 MW definition of SHP. The number of the potential sites that would fall under the 10 MW threshold is not identified.[30]

RENEWABLE ENERGY POLICY

The history of promoting renewable energy research in Israel is underpinned by the goal of ensuring independence from foreign oil. While supporting solar energy research throughout the 1970s and 1980s, Israel passed the world's first legislation requiring new residential buildings up to 27 metres high to install solar water heaters in 1980. Despite the existing drawbacks in implementing renewable energy technologies in the country, this remains a major point of progress for its energy independence.[31]

In 1996, the Electricity Market Law allowed IPPs to enter the market and produce up to 20 per cent of overall electricity in the country, accelerating its transition to clean energy. As of 2017, approximately 7,516 GWh (14.5 per cent) of the electricity supplied to customers by IEC was purchased from private producers, compared to 6,753 GWh in 2016.[16]

Israel entered the United Nations Framework Convention on Climate Change in 1996. In 1998, the country signed the Kyoto Protocol and committed to the development of alternative energy to reduce foreign fossil fuel dependence and mitigate pollution. Despite a track record of policy promoting renewable energy, Israel was almost entirely reliant on fossil fuels until 2002.[32]

Decision No. 2664 of November 2002 encouraged the construction of new renewable energy power plants by private electricity producers. Between 2002 and 2007, several solar-thermal units and solar PV power plants were built and began operating. In 2007, the National Infrastructures Ministry, which later became the Energy and Water Resources Ministry, set a new goal for a 20 per cent energy consumption reduction by 2020. A five-year research and development plan aiming at the promotion of the renewable energy sector through funding, international collaboration, professional training programmes and tax benefits began in 2008. A plan for constructing three solar power plants and a goal of a 10 per cent share of renewable energy production by 2020 was set by Government Decision No. 4450. The acceleration of solar power deployment was further supported in January 2010 when the National Planning and Building Council approved the Solar Energy Planning Strategy, which supported medium to large solar fields and rooftop PV panels. The Energy and Water Resources Ministry published a new renewable energy policy to ensure the implementation of Government Decision No. 4450's goal of 10 per cent of electricity to be produced by renewable sources by 2020, but as of 2018, the share of renewable energy, at less than 3 per cent, was far from reaching this goal.[15,32]

In 1996, a new entity (the Israeli Public Utility Authority, or PUA) was formed to monitor tariffs and costs of IEC. Starting in 2009, feed-in-tariffs (FITs) for solar PV and wind power technology became available, with small-medium wind power plants (up to 50 MW) receiving up to 1.60 ILS/kWh (0.45 USD/kWh) and with residential and industrial solar power plants (up to 60 MW) receiving between 1.07 and 2.01 ILS/kWh (0.30–0.56 USD/kWh). In 2013, these tariffs were closed and ultimately replaced by a net metering system.[33]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Israel set a goal of reaching a 10 per cent share of renewable energy in electricity generation by 2020 and has focused on policy-based support for solar power. However, the Ministry of Finance only outlines support for developing solar power, wind power and waste-based electricity generation, not hydropower, let alone SHP.[34] Furthermore, the 2012 Long-Term Master Plan for the National Water Sector of the Water Authority states that hydropower will be promoted via market forces, suggesting that there is no long-term plan for policy-based incentives for SHP.[35]

COST OF SMALL HYDROPOWER DEVELOPMENT

Though an unspecified, but likely large, share of the capacity of these projects would not be classified as small-scale, an analysis of 96 potential closed-loop off-river hydropower sites in Israel found that 11 per cent of these projects would cost under USD 577,000 per MW for power and storage components, with 35 per cent costing double the amount.[30] Israel is currently expected to spend over USD 1 billion for its joint Dead Sea water project with Jordan.[36] With inexpensive natural gas available and solar power prices falling in part due to policy emphasis, the relative abundance of high-cost hydropower projects helps explain its lack of development and focus from the Government.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Due to the prioritization of other renewable energy sources more suited to the country's climate, little explicit support for hydropower exists, let alone SHP, which is not defined by the Government. However, projects such as the Benkatina turbine have received funding from the Ministry of Trade and Labour's Eureka programme.[29] The company that invented the Benkatina turbine also demonstrates the role of maximizing the potential of local funding, such as through the Negev-focused Mack Ness Fund, which supports projects promoting population growth and economic development in the Negev region.[38] Utilizing localized funding sources such as the Mack Ness Fund may be a viable option for future SHP development as hydropower viability varies greatly by region within the country.

EFFECT OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The projected decline in precipitation due to the climate crisis further discourages SHP development in Israel, which is already burdened by uneven and limited rainfall.[5] Decreased precipitation also makes solar power, which is already receiving a stronger policy support, a more viable option due to the country's climate. Additionally, little attention is currently paid in Israel to wave-based hydropower and impending rising sea levels may further discourage its future consideration.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key factors limiting SHP development in Israel include:

- Unequal distribution of precipitation, both throughout the country and throughout the year;
- Low natural gas prices and the near-monopoly of the state (IEC) in the electricity sector;
- The high cost of solar and wind farms relative to natural gas limits the viability of pumped hydropower energy storage, despite of the advantage that it can be paired well with solar and wind power to store intermittent energy during off-peak times;
- Policy support for renewable energy focuses primarily on solar power due to precipitation trends limiting hydropower;
- Although several hydropower projects are operating or are currently under construction, the majority of them exceed standard definitions of SHP and proposed projects tend to favour larger capacities.

At the same time, the following enablers for SHP development can be identified:

- Nearly 100 new closed-loop, off-river hydropower sites totalling over 4,000 GWh of potential were recently identified, demonstrating that novel approaches to conceptualizing hydropower can increase the SHP potential of Israel;
- As intermittent solar and wind power utilization increases due to Government-promoted development, pumped hydropower storage becomes increasingly viable. The construction of new plants in recent years is a testament to this. Thus, even renewable energy policies not explicitly focused on SHP may diminish barriers to its implementation;
- The impact of the legislation that adopted solar water heaters towards reducing energy consumption from non-renewable sources has demonstrated that highly distributed energy generation approaches can be successful in Israel;
- The strong desire to reach independence from foreign fossil fuel imports may provide leverage for further promotion of SHP as a domestic energy source;
- Innovative SHP technologies, such as those utilized by the Benkatina turbine and closed-loop off-river plants, represent technical promise for future enablers of SHP deployment.

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Jordan

Jamal Jaber, Al-Balqa' Applied University

KEY FACTS

Population	10,550,000 (2019)[1]
Area	89,342 km^2[2]
Topography	Jordan has a diverse topography ranging from mountains to dry desert and can be divided into three main geographic regions: 1) the Jordan Valley region (i.e., the Ghor), in which the Jordan River runs between Lake Tiberias and the Dead Sea, and the Gulf of Aqaba; 2) the highland region (i.e., the mountainous terrain); 3) and the eastern region (i.e., the desert), which comprises more than 80 per cent of the country's area. The main topographical feature of Jordan is a dry plateau running from north to south. It rises steeply from the eastern shores of the Jordan River and the Dead Sea, reaching an average height of approximately 900 metres above sea level. The western region of the country is part of the Great Rift Valley, which includes the Jordan Valley, Dead Sea, Wadi Araba Desert and Gulf of Aqaba. In the north-western corner of the country, lies Lake Tiberias at an altitude of approximately 215 metres below sea level. The lowest point on earth is the Dead Sea, at approximately 400 metres below sea level. The eastern region is considered as part of the Syrian Desert, which extends towards the border with Saudi Arabia in the east and south of Jordan. The highest point is Jabal Ramm in the south, reaching 1,753 metres above sea level. Jordan is considered landlocked since it has no access to sea except for a short 30 km stretch of coast along the Gulf of Aqaba in the south.[3]
Climate	Jordan is characterized by long, hot, dry summers and short (November to March) but cool winters with snow on the western mountains. Its climate is influenced by the eastern Mediterranean and the Arabian Desert. The coldest month is January, with temperatures ranging between 5 and 10 °C and sometimes dropping to sub-zero for a few days. August is the hottest month with average temperatures between 20 and 35 °C. Daytime temperatures are usually high in Aqaba, the Jordan Valley and the eastern desert, especially during the summer season. Recently, daytime temperature exceeded 40 °C for a couple of days, which is an indication of climate change in the region. Summer winds are strong and hot, causing sandstorms in the desert and semi-desert areas during the spring season.[4]
Climate Change	The scarcity of water makes the management of water resources very complex from a political, technical, socio-economic and environmental perspective. Moreover, water resources in Jordan are extremely vulnerable to climate change. It is predicted that the annual precipitation may decrease, whereas maximum temperature, drought/dry days and evaporation may increase. It should be noted that in addition to the changing climate, the growing demand for fresh water in the country due to the sudden increase in population has also significantly contributed to reducing the per capita water availability.[5,6]
Rain Pattern	The annual precipitation and climatic conditions of the country do not support rainfed agriculture, except for limited regions in the northern and western highlands, where annual rainfall ranges between 250 and 450 mm. More than 80 per cent of the country territory, including the eastern and southern areas close to the border with Iraq and towards the border with Saudi Arabia, receives less than 100 mm of rainfall per year. The average annual rainfall volume in the country is approximately 1,000 million m^3, of which only less than 4 per cent infiltrates to recharge the underground water. The rainfed agricultural zone is lying in areas where rainfall exceeds 250 mm, although significant production of cereals does occur in some areas where rainfall is between 200 and 250 mm. Most of the cultivated crops are irrigated by underground water and in the Jordan Valley by the King Abdullah Canal and King Talal Dam.[7]
Hydrology	Jordan is characterized by the lack of fresh water sources. However, in the past there were three rivers: the Jordan, the Zarqa and the Yarmouk. The saline Jordan River used to supply the Dead Sea, however, it was diverted by Israel in the early 1960s to supply in-land agricultural areas. The Zarqa River is dry since its main attributes were converted to supply fresh water for the cities of Amman and Zarqa and, moreover, it currently receives substantial municipal, industrial and agricultural effluent rendering it unsuitable for domestic or irrigation uses in the dry season. Only during flood periods does the water quality improve and the river finally supplies the King Talal Dam in the north-west of Amman, the country's largest surface water reservoir supplying water for irrigating the agricultural lowland in the Jordan Valley. The Yarmouk River originates from Syria and runs along the northern border and ends up at the Alwehdah Dam. During the winter, from November to March, rainfall in the mountains is concentrated down and forms streams in the valleys, called wadis, which remain dry or with a low flow rate during most of the year.[8]

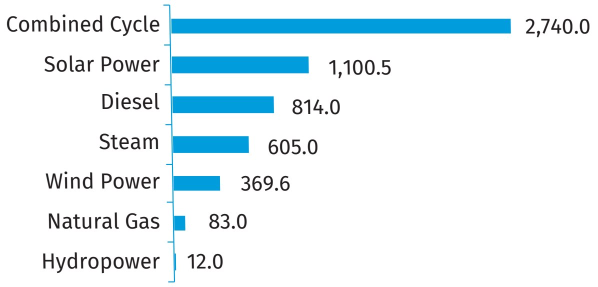
ELECTRICITY SECTOR OVERVIEW

Jordan is an energy importing country; approximately 93 per cent of its needs are supplied from abroad as natural gas, crude oil and refined products.[9] In 2019, the total energy demand was approximately 9.05 million toe, compared with 9.71 million toe in 2018 and 9.00 and 7.35 million toe in 2015 and 2010, respectively.[10,11,12] The primary energy consumption dropped by approximately 7 per cent in 2019 due to a slowdown of economic activities as a result of the general situation in the MENA region. In 2020, an additional drop in energy consumption due to the spread of COVID-19 and the suspension of most activities except the healthcare sector and some basic services. This situation is expected to continue during 2021–2023. The indigenous energy sources cover only a small fraction of the country's consumption, and in 2019 Jordan produced 0.136 million toe of natural gas and less than 0.0012 million toe of crude oil.[12] Thus, Jordan is heavily dependent on imported fossil fuels (oil products and natural gas) to fulfil its domestic energy needs in the transport, industrial, domestic heating and electricity sectors. The local energy demand is driven mainly by the electricity and transport sectors; in 2019, transportation and electricity generation accounted for approximately 35 and 30 per cent of total fuel consumption in the country, respectively.[12]

The maximum electricity demand in 2019 was 3,380 MW, while the contracted generation capacity was 4,332 MW, i.e., 128 per cent of the maximum demand. The total installed capacity was 5,728 MW at the end of 2019. The current mix is dominated by thermal power plants, of which 2,740 MW is from combined cycle plants, 814 MW from diesel units, 605 MW from steam turbines and 83 MW from gas turbines.[13] The renewable energy capacity consisted of 1,100 MW of solar photovoltaics (PV), 370 MW of wind power, 12 MW of hydropower and 3.5 MW of biogas capacity (Figure 1).[13] In 2010, almost all of the installed capacity in the country, including large industrial plants, was based on firing natural gas as a primary fuel and diesel oil or heavy fuel oil (HFO) as a secondary fuel.[13] As of 2021, a new oil shale direct combustion power plant in Attarat (470 MW) was under development by a consortium led by Esti Energia.[14] Additionally, a 13 MW wastewater treatment recovery plant is present and operating at the As-Samara wastewater treatment plant, producing 10 GWh annually.[15] This and other plants from individual power producers (IPPs) are not included in Figure 1 due to lack of comprehensive, centralized data.

The total generated electricity in 2019 reached 20,996 GWh, of which approximately 3,000 GWh (14.3 per cent) was from renewable energy sources dominated by solar PV (2,086 GWh) and wind power (892 GWh) (Figure 2). At the same time, electricity generation from hydropower was almost negligible: only 18.4 GWh. The dominant source of electricity generation was from firing fossil fuels, totalling 17,995 GWh.[13] The electricity imported from Egypt in 2019 totalled approximately 239 GWh, the electricity exported to the West Bank (city of Jericho) amounted to 91.7 GWh and a further 6.2 GWh was exported to the Iraqi border checkpoint.[12] Almost the entire population of Jordan (over 99.8 per cent) is served by and connected to the electrical grid, even the Syrian refugee camps in the north-east.[16]

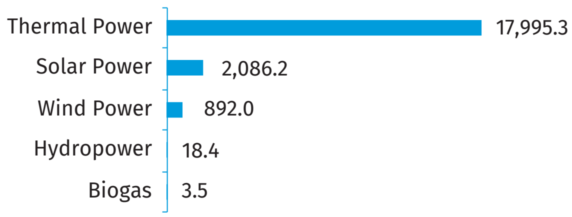
Figure 1. **Installed Electricity Capacity by Source in Jordan in 2019 (MW)**



Source: NEPCO[13]

Most of the sector's generation assets are owned and operated by local generation companies, IPPs and some industrial self-generators for on-site consumption. Most of the plants are located reasonably near to load centres, except the Aqaba thermal power plant, which is located on the Gulf of Aqaba to benefit from the sea water for cooling purposes, and renewable energy plants in the south of the country. All thermal in-land power plants are equipped with dry cooling systems due to the lack of surface water supplies in Jordan.

Figure 2. **Annual Electricity Generation by Source in Jordan in 2019 (GWh)**



Source: NEPCO[13]

During the past two decades, there was a shift from steam turbines to higher efficiency combined cycle power plants fired with natural gas and to renewable energy plants. At the same time the capacity of open-cycle gas turbines, which have the lowest efficiency in the system, was reduced. Currently, there are approximately 1,500 MW of solar and wind power plants connected to the national and/or distribution grids, with a number of projects having been completed and having come online during 2016–2018. [12,17] Such an approach has been important for improving the efficiency of power generation in Jordan and for reducing the cost of unit of electricity produced. It is important to note that no energy storage systems, e.g., pumped storage, exist at present or are planned for the near future in the country.

A further 1,000 MW of solar and wind power capacity is in the pipeline and will be connected between 2021 and 2024.[17] These projects could substantially reduce the country's energy dependency and create significant fiscal benefits. The limited existing capacity of hydropower represents the current potential limited by lack of surface water resources.[18] However, there is a good chance for a few mini-scale plants to be installed on small dams and exits of wastewater treatment plants. Furthermore, real potential exists in exploiting the elevation difference between the Red and Dead Seas: seawater flowing from the Gulf of Aqaba into the Dead Sea through a canal system at predetermined rates can be used to produce electricity as well as potable water from seawater desalination plants. While this project is expected to help in establishing new economic activities, such as tourism and agriculture, it will also ensure the supply of large amounts of highly needed electricity and water as well as the replenishment of the Dead Sea by replacing the evaporated water. Feasibility reports have shown that within this project it is possible to build hydropower plants with a total capacity of 400–800 MW.[20] However, the required capital investment is extremely high due to the great length of the canal, i.e., approximately 200 km, and the necessary infrastructure.[19]

Electricity generation in Jordan has greatly increased over the past few decades in response to rapidly rising demand. In 2010, total electricity generation sold by the National Electric Power Company (NEPCO), the sector off-taker, to the country's distribution companies and wholesale consumers stood at approximately 14,258 GWh. Five years later, in 2015, it reached 18,911 GWh and jumped to 21,000 GWh in 2019.[13] The high growth rate of electricity consumption is resulting primarily from the country's population growth and increasing economic activity, including industrial production, commercial activities, tourism and construction activities as well as the increasing number of Syrian refugees.

The national grid is under the direct supervision of NEPCO. It consists of the main conventional and renewable energy power plants, 132 kV and 400 kV transmission networks and substations (400/132/33 kV and 132/33 kV with a total capacity of approximately 15,000 MVA). The system also includes three main interconnections: (i) 230 kV with Syria, (ii) 400 kV sub-marine cable with Egypt and (iii) a 33 kV connection with the West Bank (Jericho). In addition, there are three distribution grids, which consist of 33 kV, 11 kV and 400 V networks. Each of the electricity distribution companies owns and operates the grid in its distribution area: northern, central or southern region.

The Green Corridor project, which was completed in 2021, boosted the high-voltage (HV) grid's capacity by an additional 1,200 MW, to absorb loads generated by new renewable energy projects in the south. It consists of two new transmission lines (400 kV/150 km and 132 kV/51 km), upgrading three existing lines (132 kV/100 km) and including the construction of one new 400/132 kV, 1,200 MVA electricity substation.[13] This project will reinforce the network in the central Jordan desert area, where circumstances for renewable generation are most favourable. However, in May 2016, NEPCO suspended all wheeling applications to connect to the HV network.[20] The total losses (13.77 per cent) in the grid in 2019 were distributed as follows: 2.07, 2.18 and 12.35 per cent in generation, transmission and distribution, respectively.[11] Thus, major losses occurred in the distribution grids due to technical and increasing non-technical losses.

There is a growing interest among private investors in renewable energy projects, especially those oriented towards covering the demand of the commercial, industrial and service sectors, on wheeling basis and/or net-metering. Consequently, the Government of Jordan recently revised the regulatory framework to allow aggregation by groups of customers that also produce their own electricity. This is a positive move for small-scale plants that would otherwise face barriers to market entry due to their relatively small size compared to other grid-connected assets. However, there are some obstacles that need to be removed in order to attract the private sector to invest in renewable energy projects. The most important barriers are related to subsidies in the electricity tariffs (based on cross subsidization), unlimited authority given to electricity distribution companies regarding renewable energy systems and the imposed limitation on the capacity of wheeling projects of 1 MW.

The role of the regulator, Energy and Mineral Regulatory Commission (EMRC) is to monitor the tariff system and to ensure a balanced and acceptable cost of electricity for all sectors of the economy as well as for low-income households. Thus, the regulator should allow for tariff readjustment from time to time to account for the interests of all stakeholders, including the distribution companies, following certain performance indicators.

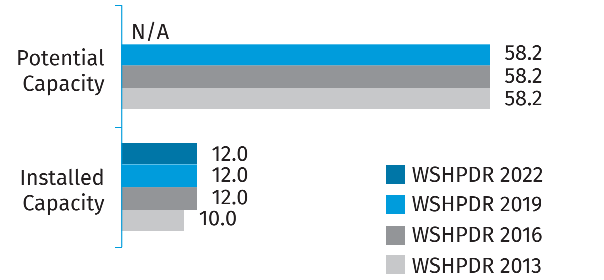
As a result of serious disruption of gas supply from Egypt during the 2010-2011 uprising, the Government of Jordan was forced to increase imports of petroleum products (diesel and HFO) to supply combined cycle and thermal power plants. Consequently, the public debt increased sharply and NEPCO was under pressure to adopt a cost-recovery strategy, which aimed to gradually increase the retail prices of electricity. From 2013, it was decided to increase the tariff by 15 per cent on a yearly basis until the end of 2016. However, the retail prices of electricity and water for the first two segments of residential consumers (1–160 and 161–300 kWh/month, respectively) are still subsidized. The prevailing electricity prices are considered among the highest in the region, as compared with neighbouring Arab countries (Table 1).

Table 1. **Retail Electricity Tariffs in Jordan in 2019**

Household electricity tariff segment	*Tariff (JOD/kWh (USD/kWh))*	*Domestic electricity tariff segment*	*Tariff (JOD/kWh (USD/kWh))*	*Commercial electricity tariff segment*	*Tariff (JOD/kWh (USD/kWh))*
First block: 1–160 kWh/month	0.033 (0.05)	First block: 1–160 kWh/month	0.042 (0.06)	First block: 1–2,000 kWh/month	0.120 (0.17)
Second block: 161–300 kWh/month	0.072 (0.10)	Second block: 161–300 kWh/month	0.092 (0.13)	Second block: > 2,000 kWh/month	0.175 (0.25)
Third block: 301–500 kWh/month	0.086 (0.12)	Third block: 301–500 kWh/month	0.109 (0.15)	Flat rate tariff for TV & broadcasting stations	0.173 (0.24)
Fourth block: 501–600 kWh/month	0.114 (0.16)	Fourth block: 501–600 kWh/month	0.145 (0.20)	Flat rate tariff for banking sector	0.285 (0.40)
Fifth block: 601–750 kWh/month	0.158 (0.22)	Fifth block: 601–750 kWh/month	0.169 (0.24)		
Sixth block: 751–1,000 kWh/month	0.188 (0.27)	Sixth block: 751–1,000 kWh/month	0.190 (0.27)		
Seventh block: > 1,000 kWh/month	0.265 (0.27)	Seventh block: > 1,000 kWh/month	0.256 (0.36)		

Source: NEPCO[13]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Jordan (MW)**



Source: NEPCO,[11] *WSHPDR 2013*,[21] *WSHPDR 2016*,[22] *WSHPDR 2019*[23]

Note: The absence of a potential capacity figure is due to a re-evaluation of the data provided in previous editions of the *WSHPDR*.

Table 2. **List of Operational Small Hydropower Plants in Jordan**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Turbine type*	*Operator*	*Launch year*
King Talal Dam	North-West Amman	5	50	Reservoir	Francis	Jordan Valley Authority	1984
Aqaba thermal power plant (non-operational)	Aqaba Gulf	7	35	Run-of-river	Francis	Central Electricity Power Generation Company	1988

Source: NEPCO[11]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition for small hydropower (SHP) in Jordan. For the purpose of this chapter, the up to 10 MW definition will be used.

The existing hydropower sources in Jordan are limited since surface water resources, such as rivers and falls, are almost negligible. Currently there are two SHP plants: one on the King Talal Dam spanning the Zarqa River with an installed capacity of 5 MW and one at the Aqaba thermal power plant, where a hydropower turbine with a capacity of 7 MW utilizes the available head of returning cooling seawater (Table 2). However, the Aqaba thermal power plant has been kept on stand-by during the past years, thus, no power was generated by its SHP units. The total amount of electricity generated in 2019 by operational SHP units was 18.4 GWh, which accounts for approximately 0.1 per cent of the national electricity generation and 0.6 per cent of renewable energy generation.[11] There are no reliable data estimating the potential of SHP in the country. The installed capacity has not changed since the *World Small Hydropower Development Report (WSHPDR) 2019*, while the previously-cited potential capacity figure of 58.2 MW has been removed due to a reevaluation of the source data (Figure 3).

At present there are no official plans for the construction of new SHP projects in the country, although good potential exists in selected sites in the western mountains, i.e., close to the Jordan Rift Valley. In addition to the only irrigation dam, King Talal, currently utilized to generate electricity, there are other existing dams that are being utilized as storage reservoirs to meet water demand during the long dry summer season. Almost all of these sites are suitable to be upgraded for SHP and/or pumped-storage use since they are located in hilly areas in the western part of the country, where annual precipitation exceeds 400 mm and may reach 600 mm with snowstorms in some areas. Evaluating the case of a pumped-storage system for each site is very difficult at this stage, since the features and characteristics are site-specific depending on topography, average annual flow and other parameters. In addition, there is a number of other small dams under construction (Table 3). Thus, further work should be conducted to assess the potential and feasibility of such plants. However, these small dams may represent an opportunity for implementing SHP plants. The average exploitable potential of existing dams in the country is estimated to be between 30 and 50 MW.[24]

Table 3. **Storage Capacity of Proposed Small Dams in Jordan**

Name	*Location*	*Proposed storage capacity (10^6 m^3)*	*Status as of early 2020*
Maa'in	Madaba	1.0	Completed
Lajjun	Karak	1.0	Under construction
Dalaghah	Tafila	1.0	Completed
Shuthim	Tafila	1.0	Completed
Bin Hammad	Bin Hammad	5.0	Under construction
Wahidi	Maa'n	1.8	Under study
Wadi Karak	Karak	2.1	Updating studies
Bayer	Eastern desert	4.0	Completed
Jafer	Southern desert	0.5	Under construction
Rukban	North eastern desert	2.0	Completed
Khanasree	Mafraq	1.0	Under construction
Ghadaf	Central desert	0.5	Completed

Source: Ministry of Water and Irrigation[6]

The contribution of hydropower will remain constant in the coming years because of limited resources unless the Government decides to proceed with pumped-storage hydropower development. Unfortunately, there is a lack of awareness and knowledge concerning SHP and its benefits; not only among the public but also among concerned governmental agencies, non-governmental organizations and municipalities. It is believed that SHP could play a positive role in the country in the future, if a targeted programme is developed to assist farmers, local communities and other consumers to harness the benefits of SHP plants where their development is economically attractive. There have been no official studies on SHP development or potential and there are no plans to develop SHP in the country. However, an academic study with preliminary estimates was performed on theoretical potential of selected sites (Table 4).

Table 4. **Small Hydropower Plants Available for Development in Jordan**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/refurbishment)*	*Type of project*
Kufranjah	Ajlun	4.5		New	Reservoir
Bin Hammad	Bin Hammad	2.5		New	Reservoir
Bayer	Eastern desert	2.0		New	Reservoir
Wadi Karak	Karak	1.1		New	Reservoir
Rukban	North eastern desert	1.0		New	Reservoir

Source: Jaber[24]

Note: Data from 2012.

RENEWABLE ENERGY POLICY

Jordan is classified as one of the four most water scarce countries in the world. The National Agenda that sets the country's development vision until 2025 stresses that the development achievements are under threat due to water scarcity, which is expected to be aggravated by climate change. The Third National Communication to the United Nations Framework Convention on Climate Change (UNFCCC) predicted that by 2050 the country will witness rising temperatures, dropping rainfall, reduced ground cover, reduced water availability, heatwaves and more frequent dust storms.[5]

The share of Jordan in global greenhouse gas (GHG) emissions represents less than 0.06 per cent.[5] Although this is a very small contribution of the total, the per capita intensity of emissions in Jordan is considerably high: at approximately 3.0 ton of CO_2-eq for the period 2010–2020. This rate significantly exceeds that of most European countries and is almost similar to those of oil producing Arab countries. This implies that there is room for energy efficiency improvement and emissions reduction in all sectors by employing renewable energy and energy efficiency measures. The Government has developed a targeted programme aiming to reduce the national GHG emissions by 1.5 per cent by 2030 compared to a business-as-usual scenario level. However, the conditional outcome target set in the Intended Nationally Determined Contribution is aiming for a 12.5 per cent reduction of emissions by 2030. The two targets will be achieved based on implementing at least 70 projects, of which many are currently under execution by the relevant institutions and will be implemented under the guidance of the overarching national Climate Change Policy of the Hashemite Kingdom of Jordan 2013–2020.[6]

The National Energy Strategy Plan 2007–2020 is a nation-wide policy encompassing strategic objectives and measures for climate change mitigation and adaptation. It is considered the first of its kind in the Arab region and, in terms of sectoral coverage, in the Middle East. The plan demonstrates the self-commitment and ambition of the Government to make progress towards energy reduction in the wake of climate change, and ensure that commitments are followed through. The National Energy Strategy Plan 2007–2020 has been extended at the end of its term to 2030 to concurrently go in line with and serve as an overarching umbrella guiding and monitoring the implementation of the 70 project and 14 per cent GHGs emission reduction pathway of activities until 2030.

According to the Third National Communication, the GHG emissions, in the reference year 2014, reached 37 million tons of CO_2-eq, of which 73 per cent resulted from the energy and transport sectors.[6] The renewable energy projects completed between 2016 and 2018 are expected to contribute to a significant reduction in GHG emissions. The net anticipated accumulated reduction of GHG emissions over this period could exceed 16 million tons, with solar PV accounting for 45 per cent of total accumulated reduction, followed by wind power, at approximately 24 per cent, and direct applications of renewable energy by 28 per cent.[13] Additional renewable energy capacities to be completed by 2025 are expected to bring total emissions reduction up to 20 million tons.[6]

At present, there is no official policy targeting hydropower in general. The Red Sea–Dead Sea project is the largest potential hydropower development, but its future depends on the decisions made on the regional level. At present, there is no plan to develop SHP plants in Jordan and no indication of an official intention to go ahead in this direction, even from the regulation point of view. Subsidies for all electricity producers were removed by 2017 in order to help NEPCO cover its costs and no other renewable support schemes are currently available.[25]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Given the very limited water resources in the country, increased evaporation and decreased rainfall will have a dramatic effect on Jordan, eventually leading to reduced recharging of groundwater reserves. The long-term effect is expected to be very serious causing soil degradation, which could lead to desertification. Also, fewer agricultural crops would be available in the market due to the lack of suitable water for the agriculture sector.

The main obstacles facing the climate change adaptation measures in the water sector include the following:

- Climate change risks are not sufficiently taken into account within sectoral policies and investment frameworks;
- Existing climate information, knowledge and tools are not directly relevant for supporting adaptation decisions and actions;
- Limited national capacity to develop sectoral adaptation responses.[6]

Adaptation to the increased water scarcity and threats related to health, food security, productivity and human security induced by climate change is key to sustaining the development of Jordan. The Government has been the implementing partner in carrying out the activities of the United Nations Country Team (UNCT) joint programme on adaptation to climate change. One component of this joint programme has focused on the Zarqa River basin, including the development of a climate change adaptation programme for the basin and a pilot climate change intervention for groundwater protection for one local community in the basin.[26]

The main conclusion is that the limited local water resources are vulnerable to global warming, and adaptation actions and measures should be taken seriously at all levels. Thus, there is a real need to implement the policies and measures which were proposed in the Third National Communication. However, the implementation of recommended measures is subject to the condition of availability of needed funds from donors and international organizations.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Jordan has some potential for hydropower development, but to date only a very small portion of this potential has been harnessed as SHP plants. Jordan has very limited surface water resources and there is an urgent need to harvest water during the winter season. Therefore, dams can have double benefits: collecting water and electricity generation. Hydropower use can be linked to efforts contributing to sustainable development through flood control, irrigation, recreation activities as well as water supply for population needs. SHP development could offer a leading renewable energy alternative for meeting electricity demand in remote and mountainous parts of Jordan, with the advantages of SHP plants including the fact that they can either be standalone or in a hybrid combination with other renewable energy sources. Moreover, hydropower can contribute to reducing the dependence of Jordan on energy imports from neighbouring countries.

However, the Government has not paid any attention to the importance of SHP and no serious effort has been made to develop the most promising sites in the country. Thus, it is necessary to start developing a national strategy for promoting SHP in Jordan and removing existing barriers. The most important barriers are:

- The absence of a regulatory framework for SHP development;
- SHP is not included in the national plans, e.g., the updated national energy strategy;
- Lack of technical and specialized staff on operation and management of SHP units;
- Lack of public awareness and knowledge about SHP;
- Limited surface water resources;
- Lack of financial resources to construct dams and install the needed equipment.

However, some of the above barriers could be addressed by inviting the private sector to participate in the development of SHP projects on the basis of public-private partnerships as well as by inviting international donors to help develop the needed local expertise and capacity.

The only identified enabler for SHP development in Jordan is the potential of utilizing existing dam infrastructure to harness 30–50 MW of power. Furthermore, despite the limited water resources in the country, there are some springs, streams and outlets of wastewater treatment plants that can be used for SHP plants. Further investigations should be conducted to assess the techno-economic potential of such SHP installations.

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Lebanon

Karim Osseiran, Ministry of Energy and Water

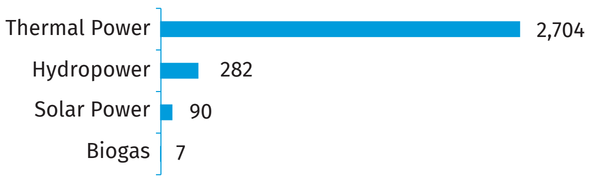
KEY FACTS

Population	6,825,442 (2020)[1]
Area	10,452 km^2[2]
Topography	Lebanon consists of four physiographic regions: the coastal plain, the Mount Lebanon mountain range, the Beqaa Valley and the Anti-Lebanon mountain range in the eastern part of the country. Waterbodies account for 1.6 per cent of the country's surface area. The highest point in Lebanon is Qurnat as Sawda, at 3,088 metres above sea level, which lies in the north of the country and gradually slopes to the south before rising again to 2,695 metres as Mount Sannine.[3]
Climate	The climate is Mediterranean, with mild to cool, wet winters and hot, dry summers. The mountainous regions of the country experience heavy winter snows. The coldest month is January with average temperatures ranging between 5 °C and 10 °C. The hottest month is August at 18 °C to 38 °C.[4]
Climate Change	The ongoing effects of climate change on Lebanon include decreasing average precipitation and changes in the timing of seasons. An analysis of annual precipitation based on 80 years of observation showed a decreasing tendency since 1970.[5] According to an ensemble of climate projections, temperatures are expected to increase by 1.2 °C by 2046, by 1.7 °C by 2065 and by as much as 3.2 °C by 2100, relative to the 1986–2005 baseline period. An increase in the length of the dry summer season by an additional 6 dry days and as many as 43 additional days with a maximum daily temperature of above 35 °C annually are also expected by the end of the century.[6]
Rain Pattern	The rainy season is in the winter, with most of precipitation falling after December. Rainfall is generous but is concentrated over only a few days of the rainy season, falling in heavy cloudbursts. Annual precipitation averages 823 mm with great variations from one year to the next as well as among the regions: 600–1,000 mm in the coastal area, 900–1,700 mm on the western mountain range, 500–900 mm on the eastern mountain range and 200–900 mm in the Beqaa Valley. Much of this precipitation, however, is lost to evaporation, neighbouring countries and the Mediterranean Sea, while a relatively small percentage remains available as underground and surface water. Approximately once in every 15 years a light powdering of snow falls as far south as Beirut.[3,5]
Hydrology	The Lebanese territory is drained by seasonal torrents and 17 main rivers, three of which — the Orontes (Assi), Nahr El Kebir and Nahr El Hasbnani — are transboundary rivers. The Litani is the largest river in Lebanon, draining a basin of 2,290 km^2 and developing its course over a total length of 170 km. There are six medium-sized rivers of 30–60 km in length with basin areas ranging between 300 km^2 and 600 km^2 and eight smaller rivers of 25–40 km in length with basin areas ranging between 100 km^2 and 300 km^2.[3,7]

ELECTRICITY SECTOR OVERVIEW

The installed capacity of Lebanon amounted to 3,083 MW at the end of 2020, including 2,704 MW (88 per cent) provided by conventional thermal power including temporary barges, 282 MW (9 per cent) provided by hydropower, 90 MW (3 per cent) provided by solar power and 7 MW (less than 1 per cent) provided by landfill gas (Figure 1).[8,9,10,11] However, reported available effective capacity was significantly lower, as it has been for many years. In 2019, available capacity and peak demand were estimated at approximately 2,449 MW and 3,669 MW, respectively.[8] Following the suspension of operation of the two temporary barges in October 2021, available capacity was reduced by a further 374 MW.[8,12]

Figure 1. **Installed Electricity Capacity by Source in Lebanon in 2020 (MW)**



Source: MoEW,[8] Government of Lebanon & UN,[9] IRENA,[10] Tsagas[11]

As a result of the gap between supply and demand, self-generation remains significant in Lebanon. A 2020 World Bank study estimated the installed capacity of diesel generators in Lebanon in 2018 at approximately 1,390 MW. The total commercial generator market size was estimated at USD 1.1 billion.[13]

Total electricity generation in Lebanon by grid-connected power plants equalled approximately 14,501 GWh in 2017, with thermal power accounting for approximately 14,036 GWh (almost 97 per cent) of the total, hydropower providing 424 GWh (3 per cent) and biogas providing 41 GWh (less than 1 per cent).[14] The share of hydropower generation typically fluctuates between 2 per cent and 4 per cent depending on yearly precipitation.[14] Meanwhile, total annual electricity demand in 2017 reached approximately 21 TWh, with most of the difference having been covered by off-grid diesel generators. The share of the supply deficit relative to demand increased from 22 per cent in 2006 to 37 per cent in 2018 and is expected to reach 56 per cent by 2026.[13]

Approximately one third of the energy produced by grid-connected power plants was not billed in 2017, with 20 per cent of generation lost to theft and billing errors, and technical losses accounting for another 14 per cent.[15] Access to electricity in Lebanon was 100 per cent as of 2019.[16] However, starting from 2011, the Syrian crisis has caused an influx of refugees into Lebanon. As indicated by a 2017 United Nations Development Programme (UNDP) assessment, this has led to a surge in electricity demand and surpassed most efforts made by the Government to improve supply, leaving the country with a higher energy deficit than in 2012. The assessment revealed that the 1.5 million displaced Syrian refugees present in the country at the time required an additional 450 MW to 480 MW of power supply, and that the percentage of displaced Syrians with non-metered connections to the grid varied from 36 per cent in the north of Lebanon to 82 per cent in Beirut and Mount Lebanon, with an average of 45 per cent across the country, with the cost of these factors to the national economy of Lebanon estimated at over USD 330 million per year.[17]

The most important player in the electricity sector of Lebanon is the state-owned company Electricité du Liban (EDL), which was granted exclusive authority in the generation, transmission and distribution sectors by Decree No. 16878 of 1964 and Decree No. 4517 of 1972.[18] The company operates at a loss, with an annual deficit of between USD 1.2 billion and USD 1.8 billion. It is hobbled by a lack of investment, rising cost of fuel, aging power plants, high technical and commercial losses in transmission and distribution, an inefficient tariff structure, electricity tariffs frozen at a level below the average cost of production and deteriorating financial, administrative, technical and human resources as well as convoluted legal and organizational frameworks.[8,19]

Following the endorsement of the Electricity Policy Paper by the Government of Lebanon in 2010, several initiatives have been launched to address the insufficient generation capacity. In 2012, the Government, represented by the Ministry of Energy and Water (MoEW), entered into a contract agreement with the Turkish company Karadeniz for renting 270 MW of reciprocating engines mounted on floating barges. The barges are based in Jiyeh and Zouk municipalities near the sites of existing thermal power plants. In 2016 the barges rental contract was extended for a two-year period until late 2018 and the capacity of the Jiyeh-based barge was increased by 110 MW. Subsequently, the contract was further extended until the end of September 2021. Following the expiration of this contact, Karadeniz stopped supplying power to the national grid on 1 October 2021, with no clear prospects for a further contract renewal and resumption of supply.[12] Furthermore, in late 2016 two reciprocating engine power plants were synchronized on the sites of the existing Zouk and Jiyeh thermal power plants, providing the sites with an additional 194 MW and 78.2 MW, respectively. Finally, as part of an operation and maintenance contract, EDL implemented upgrade packages sequentially at the Zahrani and Deir Amar thermal power plants. The upgrade was completed by the end of summer 2013 and provided a total additional capacity of at least 63 MW, in addition to enhancements in efficiency and lifetime extensions.[9]

In 2010, Law 462 introduced a legal framework for the privatization, liberalization and unbundling of the electricity sector, but has not yet been applied. In 2014, Law 462 was partially superseded by Law 288, which established that pending the implementation of Law 462, independent power producers (IPPs) could be licensed by the Council of Ministers (COM) upon joint recommendations from MoEW and the Ministry of Finance during the period between April 2014 and April 2016. Furthermore, in October 2015 the Parliament of Lebanon approved Law 54, extending the duration of Law 288 until April 2018. Finally, in May 2018 the Lebanese Council of Ministers approved a draft law calling for the extension of Law 54 for a further two-year period.[20]

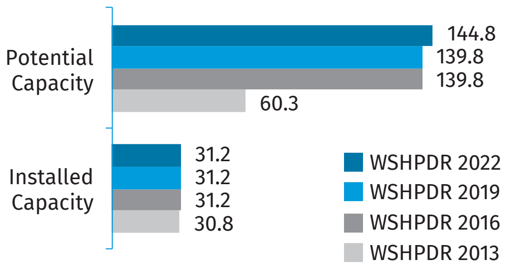
Based on the application of Law 288 and Law 54, in 2018 the Government of Lebanon signed a power purchase agreement (PPA) with a planned wind power project of 226 MW of total installed capacity. This was the first PPA signed in Lebanon for electricity produced from renewable energy sources.[10] In April 2018, the MoEW published a call for expressions of interest from private investors and companies for the construction and operation of hydropower plants, with a deadline in mid-June 2018. The goal was to incentivize the participation of the private sector in hydropower construction and financing through 20-year PPAs.[20] The implementation of the new project initiatives was however stalled by an economic crisis and a period of political instability developing in Lebanon since 2019. The impact of the COVID-19 pandemic and the Beirut Port explosion in August 2020 further aggravated the economic crisis, forcing the resignation of the Government and leading to the default of Lebanon on its sovereign debt for the first time in history. All of these factors made new project financing impossible due to the absence of public funding and the inability to attract private funding due to unprecedented challenges to the bankability of potential projects.

Electricity provided by EDL is heavily subsidized, with tariffs for end users far below the cost of production. In 2019, electricity tariffs for end users averaged 0.095 USD/kWh, while the cost of generation ranged between 0.160—0.250 USD/kWh.[21] However, as electricity supply from the grid is extremely limited, most electricity users are connected to diesel generators operated by private owners, and pay considerably more. The MoEW has been attempting to control electricity prices set by metered generator owners with only limited success, as most generator connections remain unmetered. The price for electricity from metered generators set by MoEW for December 2021 was 7,104 LBP/kWh (approximately 0.259 USD/kWh, according to unofficial exchange rates).[22,23] The price of an unmetered generator connection could reach up to 375 USD per month in 2021, with stable electricity supply still contingent on the availability of fuel.[24]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Lebanon is up to 10 MW. As of 2021, the country had seven SHP plants with a total installed capacity of 31.2 MW, with one plant (Jeita) being out of service (Table 2).[25,26] SHP potential capacity is estimated at 144.8 MW, indicating that approximately 22 per cent has been developed.[7,27] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, potential capacity has increased by approximately 3 per cent due to a reinterpretation of available data, while installed capacity has remained the same (Figure 2).[28]

Figure 2. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2021 in Lebanon (MW)**



Source: SOGREAH & MoEW,[7] Osseiran,[25] MoEW,[26] UNDP & CEDRO,[27] *WSHPDR 2019*,[28] *WSHPDR 2013*,[29] *WSHPDR 2016*[30]

Table 2. **List of Installed Small Hydropower Plants in Lebanon**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch Year*
Blaouza	Kadisha Valley	3 x 2.80 MW	La Kadisha - Société Anonyme D'électricité Du Liban Nord S.A.L. (EDL Owned)	1961
Mar Licha	Kadisha Valley	3 x 1.04 MW	La Kadisha - Société Anonyme D'électricité Du Liban Nord S.A.L. (EDL Owned)	1957
Fitri	Nahr Ibrahim River	3 x 1.66 MW	Société Phoeniciene Des Forces De Nahr Ibrahim Des Eaux Et Electricité	1951
Abu-Ali	Kadisha Valley	2 x 2.72 MW + 1 x 2.04 MW	La Kadisha - Société Anonyme D'électricité Du Liban Nord S.A.L. (EDL Owned)	1932
Al Bared 2	Nahr Al Bared River	1 x 1.20 MW + 1 x 2.50 MW	Al Bared Concession	1936
Bechare	Kadisha Valley	2 x 0.82 MW	La Kadisha - Société Anonyme D'électricité Du Liban Nord S.A.L. (EDL Owned)	1924
Jeita	Nahr Al Kalb River	1 x 0.31 MW + 2 x 0.80 MW	Water Authority for Mount Lebanon	N/A
Total		**31.24**		

Source: IRENA,[10] Osseiran,[25] MoEW[26]

In 2012, MoEW, in collaboration with the consultancy firm Sogreah-Artelia, prepared a master plan study of the country's hydropower potential along the main river streams. The study identified 32 new sites that have a potential hydropower capacity of 263 MW (1,271 GWh/year) in run-of-river projects and 368 MW (1,363 GWh/year) in peak projects (i.e., with reservoir infrastructure). The Sogreah-Artelia study identified three levels of new hydropower sites. Approximately 125 MW of the identified potential capacity from exceptionally favourable locations with low environmental impact and relatively low levelized costs. An additional 100 MW is also available and viable, although in conditions relatively less favourable than those of the first level, while a final 25 MW exists under even less favourable conditions. In all three cases, special attention must be attributed to the environmental impacts of the projects. All three levels (except for one site) have levelized costs lower than the current average EDL generation costs (which is at least 0.17 USD/kWh).[7,31]

Of the identified 32 sites, 23 are up to 10 MW, with a total potential capacity of 108.6 MW and an expected total annual generation of 533 GWh.[7] Some of the planned SHP plants may be developed within the framework of the expression of interest launched by MoEW in April 2018. Micro- and mini-hydropower plants are likely to become relatively more important in Lebanon if the country is to preserve and increase its hydropower resources. Additionally, a United Nations Development Programme Country Entrepreneurship for Distributed Renewables Opportunities (UNDP-CEDRO) study from 2013 focused on a selection of potential sites where hydropower could be utilized, namely cooling systems of nearshore power plants, irrigation channels, water networks and sewage networks. This study identified 13 pilot sites with a capacity of approximately 5 MW. However, a bigger potential for non-river SHP development remains to be identified and tapped into.[27,31]

The first hydropower plant in Lebanon was built in Béchare in 1924, under the French mandate. Lebanon experienced rapid development of hydropower plants starting from the 1920s and until the beginning of the Lebanese Civil War in mid-1970s. At its peak of development in 1976, hydropower in Lebanon provided approximately 70 per cent of annual electricity production.[32] In 2016, MoEW, with the technical assistance of the World Bank, conducted a study aiming to analyze the current legal, regulatory and administrative status of the development and rehabilitation of hydropower plants in Lebanon, to identify potential barriers and delineate further steps towards making hydropower a considerable part of the national energy mix. The study noted that although the hydropower sector has historically played a significant role in the electrification of Lebanon, today it can hardly be a driver of the country's energy sector development or the mainstay of electricity generation. The key factor is the current demand for electricity exceeding the available hydropower potential in the country by a factor of 15. Nevertheless, the hydropower sector can play an important role in the initiation of an electricity market reform, as significant experience in this field already exists. Key recommendations of the MoEW study included the following:

- Place emphasis on adopting an overall strategy aiming at raising the significance of hydropower and undertaking initiatives on legal, administrative, policy and financial issues;
- Establish a Hydropower Development Unit to enhance the capacity for the development, management and monitoring of hydropower projects;
- Establish a Hydro Account for transactions related to potential agreements in order to minimize the exposure of the hydropower sector to the liabilities of the overall energy market, reduce financial uncertainties and increase the prospects for a sustainable procedure of awarding future hydropower agreements;
- Promulgate the required legal and regulatory amendments and ministerial decisions in the areas of the Water Code, hydropower agreements, establishment of the Hydro Account and public private partnership/ independent power producers (PPP/IPPs), in order to introduce a modernized tendering procedure, a sustainable remuneration/ financing mechanism and the establishment of a proper regime for attracting investments;
- Enhance private sector participation both at the technical (i.e., engineering and environmental studies) as well as at the investment and financing levels, and consider and promote appropriate joint-venture and PPP schemes, so long as fair competition is not distorted;
- Implement an Action Plan aiming to more than double the total capacity of hydropower plants, from 282 MW as of the time of writing of this chapter to more than 600 MW in 2026.[25]

RENEWABLE ENERGY POLICY

In addition to existing hydropower capacity and developed hydropower potential, Lebanon has significant wind power potential, especially in the north. A national wind atlas has been produced, providing indicative estimates as well as aggregating the total wind power potential in the country. Furthermore, the country possesses abundant solar power resources, with an average annual insolation of 1,800–2,000 kWh/m^2.[5]

At the United Nations Framework Convention on Climate Change (UNFCCC) COP15 meeting in Copenhagen in 2009, the Lebanese Government made a pledge to increase the share of renewable energy in the country's energy mix to 12 per cent.[5] This political commitment was a major milestone of the Policy Paper for the Electricity Sector. Adopted as the national strategy for the electricity sector, the policy paper clarified the national renewable energy target as being 12 per cent of the total electricity and heat energy supply by 2020. In November 2016, the Lebanese Center for Energy Conservation launched the National Renewable Energy Action Plan (NREAP 2016–2020). To reach the overall target of 12 per cent, the NREAP set the following targets for renewable energy sources in the total energy demand for electricity generation and heating in 2020: 2.1 per cent for wind power, 4.2 per cent for solar power (including solar photovoltaics (PV), concentrated solar power (CSP) and solar water heaters), 3.2 per cent from hydropower and 2.5 per cent from biomass.[31] Although the overall target for a 12 per cent renewable energy share by 2020 was not achieved, the share of RES in electricity generation is likely to be growing rapidly, both due to the widespread adoption of solar panels as well as a decline in generation from thermal power due to a lack of fuel.[24,32]

In 2016, the Government also announced the Second National Energy Efficiency Action Plan (NEEAP 2016–2020), a strategic document paving the way for meeting the overall national objective of 12 per cent of renewable energy by 2020. The NEEAP 2016–2020 came as a continuation of the NEEAP 2011–2015 and covers 14 independent but correlated activities in the energy efficiency and renewable energy sectors. The following progress towards the established targets was recorded during the period 2011-2015:

- Banning the import of incandescent lamps to Lebanon – 45 per cent completed;
- Adoption of Energy Conservation Law and institutionalization of LCEC as the energy agency – 40 per cent completed;
- Promotion of decentralized power generation by PV and wind applications – 30 per cent completed;
- Solar water heaters for buildings and institutions – 53 per cent completed;
- Design and implementation of a National Strategy for Efficient and Economic Public Street Lighting – 60 per cent completed;
- Electricity generation from wind power – 23 per cent completed;

- Electricity generation from solar energy – 42 per cent completed;
- Hydropower for electricity generation – 34 per cent completed;
- Geothermal, waste to energy, and other technologies – 30 per cent completed;
- Building code for Lebanon – 0 per cent completed;
- Financing mechanisms and incentives – 80 per cent completed;
- Awareness and capacity building – 69 per cent completed;
- Paving the way for energy audit and ESCO business – 20 per cent completed;
- Promotion of energy efficient equipment – 8 per cent completed.[33]

The commitment of Lebanon to scaling up the use of renewable energy technologies is strengthened by the ongoing updates to its renewable energy targets. A new target aiming to meet 30 per cent of total primary energy consumption (electricity and heating demand) from renewable sources by 2030 was introduced in 2018 and formed the basis of a first update to the electricity reform paper in March 2019. In 2020, a Renewables Readiness Assessment and REmap analysis study was carried out by the International Renewable Energy Agency (IRENA) in collaboration with MoEW and the Lebanese Center for Energy Conservation (LCEC). The study provided an in-depth assessment of the policy, regulatory, financial and capacity challenges that must be overcome to achieve the targets set out for 2030. Based on IRENA's REmap analysis, Lebanon has the potential to supply 30 per cent of its electricity mix from renewable sources by 2030. With renewable power, heat and fuels all factored in, renewable energy could provide approximately 10 per cent of the country's total final energy supply in 2030, up from less than 1 per cent in 2014. The successful realization of this outcome would require making major adjustments to policy, regulatory, technology, infrastructure and financing mechanisms. A significant conclusion of the study was that the framework currently in place does not fully account for the rapid economic and technological changes taking place at the national and regional levels, and several key challenges would need to be addressed to further overcome the ongoing energy crisis.

The study proposed the following recommendations in order to enable Lebanon to meet — and, in due course, exceed — the targets set in the NREAP:

- Implement a stable and integrated regulatory framework for renewable energy development, taking into account the obstacles posed to private sector investment by several existing laws of conflicting dispositions;
- Adopt new measures for small-scale renewable energy development, including PPAs allowing developers, especially in the solar PV sector, to sell electricity to specific consumers through peer-to-peer arrangements including ones relying on blockchain technology;
- Provide additional financial incentives for solar water heaters through international grant-based financing;
- Adopt technology-specific targets for renewable energy to meet the overall goal of 30 per cent share of renewable sources by 2030, including 1,000 MW of wind power, 601 MW of hydropower, 2,500 MW of centralized solar PV power, 500 MW of decentralized solar PV power and 13 MW of biogas, and for these targets to be complemented by improvements in energy efficiency;
- Increase tariffs and reduce electricity subsidies, which may encourage public and private investments in renewable energy projects and allow for the proliferation of renewable energy technologies through small- and medium-scale deployment;
- Reinforce the electricity grid to reduce technical and non-technical losses and improve system stability;
- Weak risk allocation due to political instability, grid, resource and off-taker risk, as well as burdensome administrative schemes must all be addressed and suitable risk mitigation instruments introduced to allow international financing institutions to move from issuing concessionary loans to providing blended finance;
- Improve the transparency of land ownership across the country, particularly in regions with high wind and solar power development potential such as the Bekaa Valley, Akkar and Hermel.[10]

COST OF SMALL HYDROPOWER DEVELOPMENT

The Sogreah-Artelia study commissioned in 2012 identified 23 potential SHP sites with total project cost estimates ranging from USD 1 million to USD 42.6 million USD and costs per kilowatt of installed capacity ranging from approximately 1,300 USD/kW to 5,100 USD/kW. Construction of the plant itself, including the valves, turbine, alternators and transformers, was estimated to account for approximately 39 per cent of the total cost on average. A considerable portion of the total cost, on average approximately 27 per cent, was estimated to go towards tunnelling work.[7]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Financing for renewable energy projects, including SHP, is available in Lebanon from several sources. These include the National Energy Efficiency and Renewable Energy Action (NEEREA) financing mechanism made available by the Central Bank of Lebanon as well as loans from the Green Economy Financing Facility (GEFF) and the Lebanon Energy Efficiency and Renewable Energy Finance Facility (LEEREFF). IRENA has provided support for green finance in Lebanon by developing country-specific contract templates in collaboration with the Terawatt Initiative. Additionally, an online matchmaking service enabling developers, lenders and investors to identify providers of risk mitigation instruments (RMIs) is available through IRENA's Climate Investment Platform (CIP).[10]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Results from the Met Office Hadley Centre's PRECIS regional climate model for Lebanon indicate a reduction of rainfall of 10–20 per cent by 2040 and of 25–45 per cent by 2090, as well as an increase of 15–25 days in the number of consecutive annual dry days. These changes are expected to lead to increased hydrological stress, which, coupled with increased demand for indoor cooling due to rising temperatures, is expected to put additional pressure on the hydropower sector. Reductions in annual generation from hydropower in Lebanon are expected to amount to approximately 150 GWh by 2040 and 540 GWh by 2090, based on 2015 estimates.[6,34]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The development of SHP in Lebanon is hindered by a number of factors, as outlined below:

- Most of the existing hydropower concessions of Bared, Kadisha, Nahr Ibrahim and Litani are close to expiration (by 2030) and are selling the electrical energy produced to EDL at low tariffs;
- The current legal framework gives the exclusive rights to water resources to the General Directorate of Hydraulic and Electric Resources at MoEW, while electricity production is given to EDL;
- There are multiple stakeholders involved in the hydropower sector, which leads to excessive administrative burdens and complicates decision making;
- The geology of Lebanon is such that high costs of dam construction and limited water resources make the development of hydropower facilities unfeasible in many cases;
- While non-powered water infrastructure is available in different parts of the country, introducing a hydropower component to a dam, irrigation channel or other facility is difficult and sometimes not feasible at all if not done in the design stage;
- Water is becoming increasingly scarce, whereas demand for potable water and irrigation are increasing;
- The ongoing multifaceted crisis in the country makes access to financing difficult.

The enablers for SHP development in Lebanon include:

- The experience of Lebanon in hydropower development;
- Considerable untapped SHP potential;
- Availability of detailed studies of specific potential SHP sites.

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Saudi Arabia

Sameer Algburi and Sarmad Mahmood, Al-Kitab University; and Danila Podobed, International Center on Small Hydro Power (ICSHP)

KEY FACTS

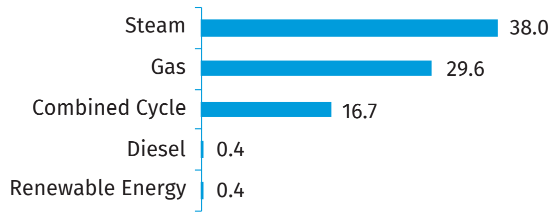
Population	34,813,867 (2020)[1]
Area	2,149,690 km² [2]
Topography	The Kingdom of Saudi Arabia represents approximately 80 per cent of the territory of the Arabian Peninsula. The country has a 2,410 kilometre-long sea coast, of which 1,760 kilometres stretch along the Red Sea and 650 kilometres represent the eastern coast of the Arabian Gulf. Forest lands in Saudi Arabia cover 2.7 million hectares and rangelands extend over 171 million hectares. The country is mostly a sandy desert, with the lowest point in the Arabian Gulf at 0 metres and the highest point at Jabal Sawda at 3,133 metres.[3,4]
Climate	Saudi Arabia has a harsh, dry desert climate with great temperature extremes. The temperature distribution across the country is controlled mainly by altitude and, to a lesser extent, by proximity to the sea. Typical daytime temperatures from May to September are between 38 °C and 43 °C across most of the country, in comparison to 30–32 °C at 2,100 metres above sea level at Khamis Mushait. However, there is usually a sharp drop of temperature at night. The annual mean temperatures range from 30 °C to 31 °C in low-lying Dhahran, Makkah and Jizan and from 22 °C to 25 °C in Riyadh and Tabuk in the north-west and stand at 20 °C in Khamis Mushait in the south-west.[2,4,5,6]
Climate Change	Between 1960 and 2010, the observed warming trend has amounted to approximately 0.41 °C and 0.16 °C per decade for summer and winter temperatures, respectively. An extreme heatwave has been observed in Jeddah and other parts of the country in 2010, with temperatures reaching 52 °C.[6]
Rain Pattern	Most rainfall in Saudi Arabia comes in the winter and spring. However, rainfall is unreliable and annual average totals are approximately 100 mm and less in inland parts of the country. For example, in Tabuk in the north-west, average annual rainfall amounts to 35 mm. The most abundant precipitation falls in the mountainous region in the far south-west of the country. In this area, rainfall typically occurs in the spring and summer, raising annual totals to 199 mm in Khamis Mushait and 141 mm in Jizan on the adjacent coastline. In the northern half of the country, rainfall occurs mainly between November and April, caused by weather systems moving eastwards from the Mediterranean or Northern Africa.[6,7,8]
Hydrology	Saudi Arabia is a desert country with no permanent rivers or lakes.

ELECTRICITY SECTOR OVERVIEW

The total installed capacity of Saudi Arabia was approximately 85.2 GW in 2019, with the overwhelming majority coming from non-renewable thermal power. Steam turbine plants provided 38.0 GW (45 per cent) of the total, gas turbine plants provided 29.6 GW (35 per cent), combined-cycle plants provided 16.7 GW (20 per cent), diesel generators provided 0.4 GW (less than 1 per cent) and renewable energy sources (RES), primarily solar power, likewise provided 0.4 GW (less than 1 per cent) (Figure 1).[9]

Saudi Arabia is divided into five geographical regions: Eastern, Central, Western, Southern, and Northern. In the Eastern, Central and Western regions, there is an interconnected grid that feeds the major load centres of each region. In these three geographical regions, isolated systems represent only a small percentage of the total load. In the Southern region, there are four autonomous systems that are not presently interconnected with each other. There is a plan to link these four autonomous systems into a unified grid for the Southern region's major load centres. In the Northern region, there are a number of isolated systems.

Figure 1. **Installed Electricity Capacity by Source in Saudi Arabia in 2019 (GW)**

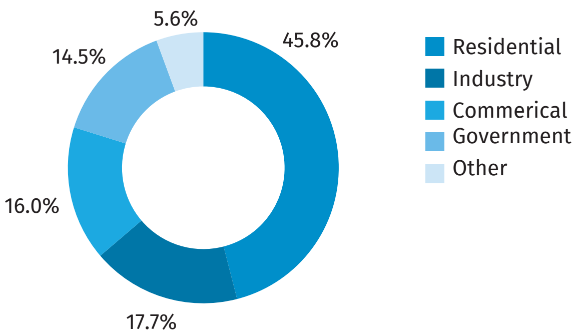


Source: ECRA[9]

The Eastern Operating Area (EOA) is responsible for the largest share of electricity generation in the country. EOA is connected to the Central Operating Area (COA) by a 230 kV double-circuit line and two 380 kV double-circuit lines.

Total electricity generation in Saudi Arabia was 340.9 TWh in 2020, decreasing by approximately 1 per cent from 343.7 TWh generated in 2019. Generation from RES was limited, with solar power contributing approximately 1 TWh in 2020.[10] The electrification rate in Saudi Arabia was 100 per cent as of 2019.[11] Electricity consumption was approximately 279.7 TWh in 2019, declining from 289.9 TWh the previous year. In 2019, the residential sector accounted for approximately 128.1 TWh (nearly 46 per cent) of total consumption, the industrial sector accounted for 49.4 TWh (18 per cent), the commercial sector for 46.0 TWh (16 per cent), the government sector for 40.5 TWh (15 per cent) and other sectors for 15.6 TWh (6 per cent) (Figure 2). Peak electricity demand in 2019 reached 62,076 MW.[9]

Figure 2. **Electricity Consumption by Sector in Saudi Arabia in 2019 (%)**



Source: ECRA[9]

Electricity consumption in Saudi Arabia was fairly stable between 2015 and 2018 and declined slightly in 2019.[9] However, climate has a significant impact on electricity consumption in the country, as air conditioning accounts for 70 per cent of all electricity use. This contributes to market seasonality, with summer peak demand almost double that of the winter average. It is estimated that total installed capacity in Saudi Arabia must rise to 120 GW by 2032 in order to meet the projected growth in electricity consumption. Additional proposals include merging the electricity grids of Saudi Arabia and several other Gulf States and linking them to the electricity grids of the European Union (EU), Egypt and Turkey. A power sharing arrangement with the EU is also proposed, providing excess power to the EU during the winter season, while receiving additional power during the summer peak demand period in Saudi Arabia itself.[12]

The Saudi Electricity Company (SEC) is the largest electricity producer in the country, operating 53 GW of installed capacity as of 2020 and being responsible for approximately half of total generation. In 2020, SEC connected an additional 776 MW of generating capacity to the national grid. The company has set the following objectives, to be completed by 2023:

- Increasing generating capacity by an additional 8,203 MW;
- Adding 5,402 kilometres of transmission lines and 86 transmission substations;
- Adding 126,388 kilometres of lines to the distribution network;
- Delivering electricity to an additional 1 million customers to account for population growth, reaching a total of 11 million customers.[13]

Electricity tariffs in Saudi Arabia were last modified in 2017 by Council of Ministers Resolution No.166 and have been in effect as of 1 January 2018. Tariffs include a consumption tariff that varies by consumer category as well as a monthly connection charge based on breaker capacity. Connection charges range between SAR 10 and SAR 30 (USD 2.67–8.00). Consumption tariffs are provided in Table 1.[14]

Table 1. **Electricity Consumption Tariffs in Saudi Arabia**

Consumption category (kWh)	*Consumer category tariff (SAR/kWh (USD/kWh))*					
	Residential	*Commercial*	*Agricultural and charities*	*Governmental*	*Industrial*	*Private educational and medical facilities*
1–6,000	0.18 (0.049)	0.20 (0.054)	0.16 (0.043)	0.32 (0.086)	0.18 (0.049)	0.18 (0.049)
Over 6,000	0.30 (0.081)	0.30 (0.081)	0.20 (0.054)			

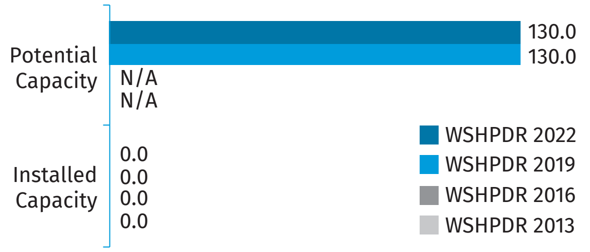
Source: SEC[14]

SMALL HYDROPOWER SECTOR OVERVIEW

Saudi Arabia has no installed hydropower facilities of any kind and no formal definition of small hydropower (SHP). However, dams have been constructed to make use of the little rainfall to recharge subterranean water supplies and control flooding. There are more than 200 dams in the country, with a cumulative reservoir capacity of 774 million m^3. The King Fahd Dam is the largest in the country by reservoir volume, with a storage capacity of 325 million m^3. At the same time, the effectiveness of dams in Saudi Arabia in containing rainfall water is greatly undermined by the excessive evaporation and sedimentation.[12,15]

Potential hydropower capacity from the Wadi Baish Dam and the King Fahd Dam has been estimated at between 9 MW and 10 MW each, from the Wadi Hali Dam between at 8–9 MW, from the Wadi Rabigh Dam and the Al-Lith Dam at 7–8 MW each and from the Al-Madeeq Dam at 5–6 MW. Hence, the total estimated potential capacity that could be installed at all six dams is between 45 MW and 51 MW. Assuming 50 per cent operation at peak installation, these plants could generate electricity at an average of 210 GWh per year. In addition to the six dams mentioned above, there were also 51 other smaller dams with estimated total potential capacity of 82 MW. Assuming 50 per cent operation at peak installation, the plants would generate electricity at an average of 360 GWh per year. As all proposed projects would have an installed capacity of under 10 MW, the total SHP potential capacity of the country can be estimated at approximately 130 MW (570 GWh per year) (Figure 3).[16]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Saudi Arabia (MW)**



Source: Obaid,[16] *WSHPDR 2013*,[17] *WSHPDR 2016*,[18] *WSHPDR 2019*[19]

RENEWABLE ENERGY POLICY

Saudi Arabia has the world's largest proven oil reserves, the world's fourth largest proven gas reserves and is the world's 20th largest producer and consumer of electricity. Saudi Arabia makes negligible use of RES and almost all its electricity is produced from the combustion of fossil fuels. At the same time, Saudi Arabia has considerable RES potential, mainly in the form of solar energy. Unlike other countries exhibiting high population density, the country's vast desert can host large solar installations and its huge deposits of clear sand can be used to manufacture silicon photovoltaic (PV) cells. The Government of Saudi Arabia is interested in increasing generation from RES in order to meet the domestic power needs, free up oil for export and drive natural gas consumption towards sectors with higher added value such as petrochemicals.

In 2012, Saudi Arabia launched an ambitious USD 109 billion plan to install 41 GW of solar power (including 25 GW of concentrated solar power and 16 GW of solar PV projects), 9 GW of wind power, 3 MW of waste-to-energy projects and 1 MW of geothermal power by 2032, corresponding to 30 per cent of planned electricity generation capacity for that year. The RES sector is expected to bring important returns, in particular in terms of employment. In addition to the diversification of the domestic energy mix, RES is expected to contribute to the reduction of emissions growth (NOx, SOx and CO2), effluents and water usage, as well as provide an alternative means of serving remote areas in a more economic and environmentally sustainable manner. However, RES development has been slow, with less than 1 per cent of the country's installed capacity provided by RES as of 2019.[9]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The two key obstacles to SHP development in Saudi Arabia are:

- No permanent rivers and very little rainfall make SHP development on natural watercourses a near impossibility;
- Water insecurity stemming from the above factor drives the country to carry out desalination to meet its water supply needs, making any power sector development that requires fresh water abstraction very unlikely;
- Heavy reliance on thermal power from cheaply available domestic fuel sources hinders RES development as a whole.

Possible opportunities for SHP development in Saudi Arabia include:

- The installation of SHP turbines on outflow from existing non-powered dams, yielding a considerable potential SHP capacity;
- Energy recovery solutions utilizing SHP installed on water distribution networks.

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Syrian Arab Republic

Bassam Al Darwich, Ministry of Electricity; and Alsamaoal Almoustafa, Syrian Atomic Energy Commission

KEY FACTS

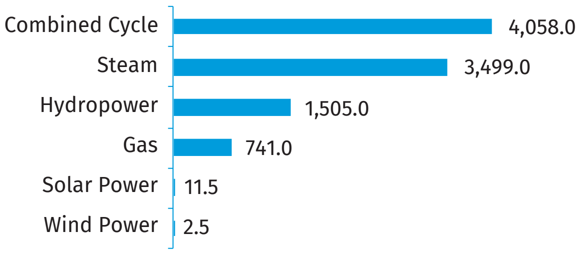
Population	26,262,000 (est. 2020) [1]
Area	185,180 km^2 [1]
Topography	The Syrian Arab Republic lies on the eastern coast of the Mediterranean Sea. Topographically, Syria may be divided into four regions: the coastal region between the Syrian Coastal Mountain Range and the Mediterranean; the mountainous and highlands region that runs from the north down to the south of the country parallel to the Mediterranean Sea; the interior or plains region that comprises the plains of Damascus, Homs, Hama, Aleppo, Hassakeh and Dara'a, and is located east of the mountainous region; and the desert region or Badiah in the south-eastern part of the country. The highest point in the country is Mount Hermon at 2,814 metres above sea level.[2,3]
Climate	A Mediterranean climate generally prevails in Syria, characterized by a rainy winter and a dry, hot summer. Daily differences between the maximum and minimum temperatures are generally quite significant in most parts of the country, sometimes reaching 23 °C in interior areas and 13 °C in coastal areas. The daily fluctuations in temperature are greater in the interior and desert areas as compared with areas on the coast and at high altitudes. December and January are the coldest months of the year, while July and August are the hottest. In winter the temperature frequently falls below 0 °C but rarely below -10 °C, while in the summer it often reaches 48 °C.[2,3]
Climate Change	Ongoing climate change in Syria has resulted in drought, heat waves and dust storms, while climate change impacts on Syria through 2041 are expected to include a reduction in precipitation and rising temperatures. Projections of long-term climate change in Syria based on IPCC climate change scenarios A2 and B2, published in 2010, indicated that the temperature rise in Syria in the coming decades will be higher than the global average. By 2041, a temperature increase of 2.0–2.1 °C is expected for the north-western and south-eastern parts of the country relative to the 1961–1990 baseline scenario, with other regions experiencing an increase of 1.0–1.2 °C. Climate change impacts on internal water resources through the 2050s are projected to cause a 30 per cent decline in groundwater relative to the 1961–1990 baseline period.[3,4]
Rain Pattern	Total annual precipitation in Syria varies highly depending on the region. Annual precipitation ranges from 100 mm to 150 mm in the north-western parts of the country, from 150 mm to 200 mm from the south to the central and east-central areas, from 300 mm to 600 mm in the plains and along the western foothills and from 800 mm to 1,000 mm along the coastal zones, reaching 1,400 mm in the mountains. Average annual rainfall is approximately 250 mm.[3]
Hydrology	Water resources in Syria are limited and distributed among seven basins. The Tenth Five-Year Plan of Syria estimated the total water resources in the country at 15 billion m^3, with 10 billion m^3 of surface water and another 5 billion m^3 underground. There are 16 main rivers and tributaries in the country, mainly located in the northern part of country, with the Euphrates being the largest.[2,3]

ELECTRICITY SECTOR OVERVIEW

The primary indigenous energy resources in Syria are oil, natural gas and limited hydropower resources. The Syrian energy sector is characterized by the dominance of fossil fuels and lack of renewable energy sources (RES). Historically, the energy sector was strategically important for achieving growth in all other sectors of the economy and prior to 2011 the oil and gas sector accounted for approximately one-fourth of the Government's revenue. However, the country's indigenous energy resources are limited and it is expected to become a net oil importer in the foreseeable future even without accounting for the impact of the ongoing conflict. The energy sector of Syria has encountered several challenges as a result of the conflict and subsequent sanctions imposed by the United States and the European Union (EU). The energy infrastructure, including oil and natural gas pipelines and electricity transmission networks, has been damaged, which has hindered the exploration, development, production and transport of the country's energy resources.[4,5,6]

According to the technical statistical report for 2020 prepared by the Public Establishment of Electricity Generation (PEEG), at the end of 2020 the total installed capacity of Syria was 9,803 MW. Of the total, 1,505 MW (15 per cent) was from hydropower plants, while the remaining 8,298 MW (85 per cent) was represented by thermal power plants, including combined cycle turbines with 4,058 MW (41 per cent), steam turbines with 3,499 MW (36 per cent) and gas turbines with 741 MW (8 per cent).[7] Additionally, a number of RES projects not wholly owned by the Ministry of Electricity, and therefore excluded from the PEEG reports, were in operation in 2020. This includes approximately 11.5 MW of solar power located mainly in Tartous and As-Suwayda, as well as a single 2.5 MW wind power plant, bringing the total installed capacity of the country in 2020 to 9,817 MW (Figure 1).[7,8]

Figure 1. **Installed Electricity Capacity by Source in Syria in 2020 (MW)**



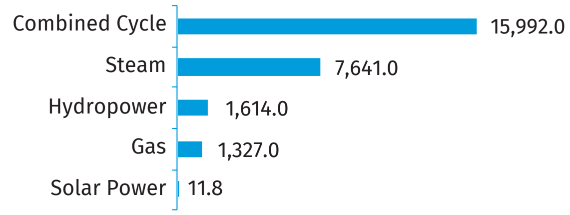
Source: PEEG,[7] Alemam, H.[8]

The last 10 years of crisis and war have heavily affected the country's electricity sector, with many power plants out of service and serious negative impacts on both electricity demand and supply (including available capacity of the system as well as actual generation). Physical damage to electricity infrastructure from the war has been very severe, but the functionality of the transmission grid has so far been largely maintained. Two major thermal power plants (the 1,065 MW Aleppo plant and the 544 MW Zyzoun plant) were fully out of service as of 2020 and in need of deep rehabilitation.[7]

As a result, of the total installed capacity of 9,803 MW reported by PEEG in 2020, less than 5,581 MW was technically available (4,481 MW of thermal power and barely 1,000 MW of hydropower). However, taking into account the severe fuel shortages, the operable capacity may be less than 30 per cent of the technically available total. The available fuel is sometimes barely enough to operate 1,700-2,000 MW.[9]

Total electricity generation in 2020 decreased to approximately 26,586 GWh from more than 49,000 GWh in 2011, a decrease of nearly 46 per cent.[7] In particular, generation by hydropower decreased dramatically, from 2,992 GWh in 2011 to 1,614 in 2020 (a decrease of over 46 per cent). Meanwhile, generation by combined cycle turbine plants in 2020 equalled 15,992 GWh, by steam turbine plants 7,641 GWh and by gas turbine plants 1,327 GWh. Solar power produced almost 11.8 GWh in 2020, while wind power generation was negligible (Figure 2).[7,8]

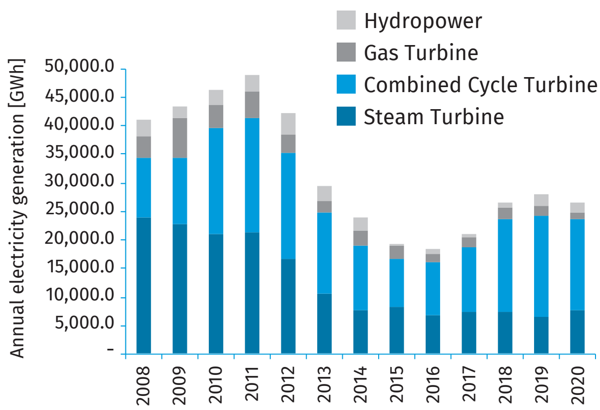
Figure 2. **Annual Electricity Generation by Source in Syria in 2020 (GWh)**



Source: PEEG,[7] Alemam, H.[8]

Historical generation by source over the past decade is displayed in Figure 3. A steep decline in generation can be observed from 2011 to 2016, followed by a partial recovery between 2016 and 2019. Finally, 2020 again recorded a decline in generation that can be partially attributed to fuel shortages caused by a new round of sanctions enacted in 2019 and partially to maintenance constraints, leading to scheduled load shedding throughout the country.[9]

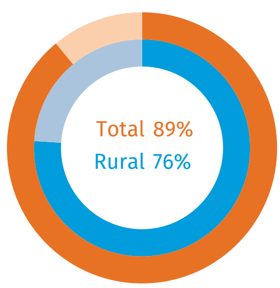
Figure 3. **Annual Electricity Generation by Source in Syria in 2008–2020 (GWh)**



Source: PEEG[7]

Electricity access in Syria was 89 per cent nationally in 2019, but only 76 per cent in rural areas (Figure 4). As with other indicators, electricity access has declined over the past decade, from 93 per cent of overall electricity access and 83 per cent of rural access in 2010.[10]

Figure 4. **Electrification Rate in Syria in 2019 (%)**



Source: World Bank[10]

Hydropower is currently the only significant RES in Syria, providing between 2,000 GWh and 4,000 GWh per year. The hydropower resources in Syria are limited by low precipitation and flow from international rivers.[6,7] Low generation relative to installed capacity is due to the fact that hydropower plants in Syria are operated mostly during the peak load period rather than continuously. The Al-Thawra Dam (800 MW) and Tishreen Dam (630 MW), both on the Euphrates, provide approximately 90 per cent of the hydropower supply. The Al-Baath Dam on the Euphrates (75 MW) and 3 other small, very old hydropower plants with a total capacity of 23 MW make up the 1,528 MW installed capacity total.[6]

The electricity sector in Syria is organized under the Ministry of Electricity, which regulates and manages the sector. PEEG, operating as part of the Ministry of Electricity, is responsible for planning, development, operation and maintenance of the generating plants. The Public Establishment for the Transmission and Distribution of Electricity (PETDE) and its 14 regional branches are responsible for the transmission and distribution network.

However, hydropower plants under the supervision of the General Establishment of Euphrates Dam (the Thawra, Baath, and Tishreen hydropower plants) are supervised by the Ministry of Irrigation.[6,7,11]

While the ongoing situation has prevented large-scale development of RES in Syria, some progress has been made in recent years in the adoption of both on-grid and off-grid solar power. On-grid solar power capacity has increased from a mere 311 kW in 2017 to 11,488 kW in 2020.[8] Solar power projects have been primarily implemented in the north-western region (with the city of Tartous accounting for 57 per cent of the installed capacity), in addition to Hama, Homs, Damascus and suburbs and As-Suwayda in the southern region. Individual installed capacities are rated at below 1 MW in all cases. As of the end of 2020, an additional 117.13 MW of solar power projects had been licensed for construction, including projects intended to supply power to industry in cities, including Aleppo (33 MW) and Homs (30 MW). Moreover, two large solar power projects are under negotiation with private investors, including a 100 MW solar power plant to be constructed in the industrial part of Damascus, as well as a 300 MW solar power plant in Harran Al-Aoamed in the Damascus suburbs. However, the majority of these projects are still in the early negotiation phase, with the exception of the 33 MW solar power plant in Aleppo, which has already commenced construction.[8,9,12,13] Off-grid solar power capacity installed by homeowners and small businesses is hard to quantify. However, it is estimated at two to three times the quoted on-grid capacity, owing to the rising popularity of solar power in providing electricity for water pumping for irrigation and household use.[9]

Electricity tariffs in Syria are subsided and despite periodic adjustments are still below cost recovery level, which does not encourage energy efficiency or more penetration of RES among consumers. Electricity tariffs vary based on the type of consumer, volume of electricity used and voltage. Most electricity subsidies are applied towards household consumption at the lower levels of monthly usage.

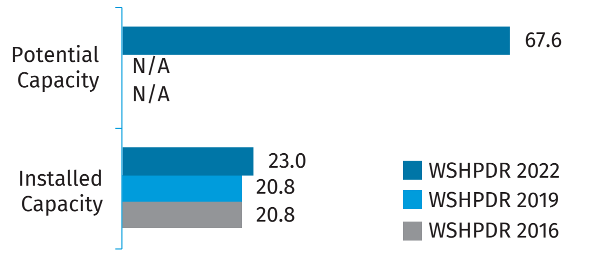
The average electricity tariff rate in Syria has consistently been very low by regional standards — approximately 0.044 USD/kWh before the year 2011 and less than USD0.021/kWh in 2021 (taking into account the current deterioration of the SYP/USD exchange rate, with the official rate set at 1,256 SYP/1 USD). This was comparable to the tariffs in oil and gas exporting countries and significantly lower than the tariffs in regional non-oil rich countries such as Jordan, Lebanon, and Morocco.[9,14]

In this context, a number of studies were carried out to examine the options for tariff adjustment, including an EU-funded project in 2006 and another study within the Electricity Sector Strategy Note prepared by the World Bank at the request of the Government of Syria in 2009. The studies suggested that setting the average long-range marginal cost (LRMC)-based tariff at or above 0.091 USD/kWh and accelerating tariff increases above the rate of inflation would be necessary to achieve self-financing by the electricity utilities. [15,16]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in the Syrian Arab Republic is up to 10 MW.[10] The installed capacity of SHP in Syria of 23 MW has not changed in recent years, while new data on potential SHP capacity suggests a maximum of 44.6 MW of untapped potential capacity and hence 67.6 MW of total SHP potential capacity (Figure 5). Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity has increased by approximately 10 per cent due to more accurate data becoming available.[7,17,18]

Figure 5. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Syria (MW)**



Source: PEEG,[7] National Committee for Small Hydro Power Potential,[17] *WSHPDR 2019*,[18] *WSHPDR 2013*,[19] *WSHPDR 2016*[20]

According to the annual statistical reports of PEEG published between 2003 and 2020, there are three SHP plants in Syria, with a nominal installed capacity of 23 MW: the Barada Valley SHP plant, the Shezar SHP plant and the al-Rastan SHP plant (Table 1). However, these three plants are very old and primarily operated seasonally, with available capacities additionally fluctuating based on river flow volumes.

For long periods the available capacity of these three plants can actually drop to 0 MW, as happened between 2005 and 2011. An additional SHP plant, the 1.5 MW al-Takkia plant cited in *WSHPDR 2019*, has been entirely out of commission since 1958.[7,9]

Table 1. **List of Operational Small Hydropower Plants in Syria**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Al Rastan	Al Assi River	7	Reservoir	PEEGT	1962
Barada Valley	Barada River	8	Reservoir	PEEGT	1957
Shezar	Al Assi River	8	Reservoir	PEEGT	1932

Source: PEEG,[7] Darwich & Almoustafa[9]

During the last decade, and owing to the ongoing shortages in fuel and natural gas supplies and the corresponding negative effects on electricity generation, more attention has been given to developing micro- and small hydropower. In 2020, a national committee was established in Syria to map the potential for SHP exploitation on different rivers and natural water flows, as well as exploring the possibility of producing electricity from outflows of sewage water treatment facilities.[17] The report's findings estimate a considerable SHP potential in the country, including:

- The potential for annual electricity production from outflow of the sewage treatment stations is approximately 53.6 GWh. The report recommended taking advantage of the wide distribution of sewage treatment stations across the country and their proximity to population centres.
- The potential SHP capacity of the rivers of the coastal region of Syria was estimated at 32.3–36.3 MW, including a number of SHP units to be installed at the 16 Tishreen Dam with a 26–30 MW cumulative capacity.
- The viability of replacing pressure breaker valves on water distribution pipes with SHP turbines in three regions of the country was also assessed, estimating the following potential capacities: Damascus and Damascus suburb with 6.1 MW, the coastal region with 3 MW and Homs with 0.67 MW.[17]

Table 2 provides a summary of potential SHP sites and projects in Syria, including the projects examined by the aforementioned study as well as the defunct Al-Takkia SHP plant that may present an opportunity for refurbishment. The total assessed SHP potential capacity of the listed projects is approximately 40.6–44.6 MW, while the potential annual generation is 221.6 GWh.[9,17] Further studies are necessary to analyze the scope for small and micro-hydropower in the country, in particular studies on standalone power plants as well as on power plants linked together to form regional mini-grids.

Table 2. **List of Potential Small Hydropower Sites in Syria**

Name	*Location*	*Potential capacity (MW)*	*Potential annual generation (GWh)*
16 Tishreen Dam (multiple SHP units)	Coastal	26.0–30.0	84.0
Al-Thawra	Coastal	1.5	2.3
Baloran	Coastal	0.3	0.9
Al-Basel	Coastal	1.5	4.3
Al-Takkia	Al-Assi River	1.5	N/A
Sewage Water Treatment Stations	Nationwide	N/A	53.6
Pressure Breaker Valves	Coastal	3.0	26.3
	Damascus	6.1	44.3
	Homs	0.7	5.9
Total		**40.6–44.6**	**221.6**

Source: Darwich & Almoustafa,[9] National Committee for Small Hydro Power Potential[17]

RENEWABLE ENERGY POLICY

Presently, electric power generation from RES in Syria includes SHP, large hydropower, solar power and one wind power plant. Attempts to formulate an appropriate RES policy framework have taken place over the last decade despite the ongoing war, aiming to overcome the existing barriers and promote implementation of RES generation options.

Studies suggest that Syria has a high untapped potential with regard to wind and solar power. The wind power potential in Syria is very promising, as annual mean daily wind speed in some regions of the country reaches 13 m/s.[21] The theoretical wind energy potential in Syria is estimated at 40 GW, with approximately 12 GW considered a practical achievable upper limit for all energy purposes, including electricity generation.[2,22] Moreover, Syria, like other Mediterranean countries, is rich in solar irradiation, with average solar irradiation on a horizontal surface ranging between 4.4 kWh/m^2 per day in the mountainous region to 5.2 kWh/m^2 per day in the Syrian desert. The sun shines approximately 2,800–3,200 hours per year and there are only approximately 40 cloudy days per year.[5,6,21,23,24]

Aiming to take advantage of these resources, Syria adopted measures in 2011 to attract investor interest in RES. It has opened its market for private developers, adopted feed-in tariffs (FITs) and a net metering policy subsidized by the state, authorized the business-to-business sale of renewable electricity and announced tenders for public competitive bidding to develop the first large-scale wind power projects.[21] FITs are subsidized by the Government. As of 2020, tariffs were set at the levels indicated in Table 3, as per Government of Syria Resolution 1113. Tariffs for solar energy projects are guaranteed for a 25-year period.[9]

Table 3. **Feed-in Tariffs for Electricity Generation in Syria in 2020**

Source type	*Rate (USD/kWh)*
Solar photovoltaic (PV) power	0.082
Hybrid solar PV and wind power	0.076
Wind power	0.070
Hydropower	0.070
Biomass	0.067
Landfill gas	0.067

Source: Darwich & Almoustafa[9]

A major factor driving investment in solar power in Syria is the adoption of the National Renewable Energy Strategy to 2030 in 2019. In accordance with this strategy, the contribution of RES to the energy balance is targeted to reach 5 per cent of the total primary energy demand by 2030, while the annual electricity generation from solar PV and wind power plants is expected to meet approximately 7 per cent of the energy demand by 2030. Specific targets include 1,500 MW of solar PV projects, 900 MW of wind turbines and 1.2 million solar heaters.

The ambitious RES plan will be implemented through several means and in cooperation with a wide range of partners. The projects will consist of turn-key projects carried out by the Ministry of Electricity, investment projects carried out by the private, public and joint sectors and projects implemented by electricity consumers, including the agricultural, water resources, industrial, commercial, domestic, government and management sectors as well as places of worship. Additionally, certain waste and solar heater projects are expected to be funded through the Renewable Energy Support Fund.

The more decentralized distribution of RES-based generation compared to fossil fuel-fired power plants will require reconfiguration of the national electricity grid to better integrate power inputs from sources with high output variability and to reduce transmission losses from the more remote RES electricity generation sites.

Apart from the currently unfavourable security situation, the main challenges in developing RES in Syria arise from the socioeconomic impact of technology replacement, energy prices and subsidies that are below the cost recovery level, lack of public awareness, the current regulatory framework and insufficient public financial support.[9,25]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change and water use patterns have put increasing pressure on the water resources in Syria in recent decades, with consumed water exceeding available water resources by as much as 30 per cent in the early 2000s, compared to a nearly 1-to-1 ratio in the early 1990s. A decline in groundwater levels has taken place in parallel with decreasing surface water availability. In one stark example, the Khabour River, the largest tributary of the Euphrates in Syria, went completely dry in 1999, having experienced a continuous decline in flow since the 1970s. Another major river, the Barada, is expected to experience a 37 per cent decline in flow at the source by 2039, relative to 2006–2007. Overall, the deficit in water resources is projected to increase by 200 per cent by 2027, relative to the observed deficit during the 1995–2005 period.[3]

In Syria, over 90 per cent of water use is dedicated to agriculture.[3] As such, the demands of the agricultural sector can be expected to compete with hydropower water demand in the foreseeable future.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Some of the most important barriers to SHP development in Syria are outlined below:

- Hydropower resources of all sizes are limited by low precipitation and river flows, with most of the available hydropower potential having already been utilized;
- The current conflict situation has put almost all development plans on hold;
- A lack of detailed studies on the potential for small and micro-hydropower; additional studies must be conducted, in particular on the interconnectivity of SHP plants along mini-grids.

Enablers for SHP development include:

- Insecurity of access to fossil fuels, which have traditionally formed the mainstay of the electricity generation sector in Syria, prompting the need to develop alternatives;
- Recent surveys point to various forms of untapped SHP potential existing in Syria, including potential for energy recovery projects built on existing water infrastructure.

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Turkey

Alaeddin Bobat, University of Kocaeli; and Ozturk Selvitop, Ministry of Energy and Natural Resources of Turkey

KEY FACTS

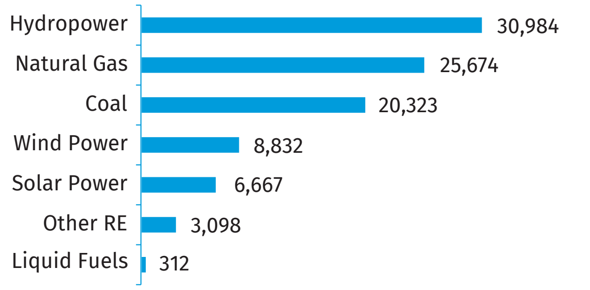
Population	83,614,362 (2020)[1 1]
Area	814,572 km² [2]
Topography	Despite the existence of broad plains and plateaus, the topography of Turkey is largely hilly and mountainous across the entire territory. The central Anatolian Plateau dominates the territory, with the exception of narrow coastal plains on the Aegean and Black Seas. Turkey has one peak of over 5,000 metres in altitude (Mount Ararat), three over 4,000 metres and 219 peaks exceeding 3,000 metres. Turkey lies within a seismically active area.[3]
Climate	The climate in Turkey is semi-arid. Coastal areas have a Mediterranean climate with hot and dry summers between June and August and temperatures reaching 35 °C. In the higher interior Anatolian Plateau, the winter months (between December and February) can be very cold, with temperatures reaching -7 °C. In the period between 2008 and 2017, the mean temperature was 13.9 °C.[4]
Climate Change	Turkey is highly vulnerable to climate change and is already facing an observed warming trend in temperatures and a decreasing trend in precipitation. This is having a major negative effect on water availability for food production and rural development, further exacerbating the social and regional disparities in a country characterized by a wide (and widening) gap between the eastern and south-eastern provinces and the rest of the country.[5]
Rain Pattern	The average annual rainfall in Turkey is 574 mm, but in some years, it is lower due to drought and climate variation. The Eastern Black Sea region receives the most rainfall (1,200–2,500 mm/year), while the Central Anatolia region (around Salt Lake) receives the least rainfall (250–300 mm/year). In other parts of Turkey, except for coastal settlements in the Mediterranean and South Aegean regions, snowfall occurs during the winter months. Approximately 70 per cent of the total precipitation occurs between October and April.[4]
Hydrology	Turkey is divided into 25 river basins. Most rivers originate in Turkey and there are more than 120 natural lakes, 293 dam reservoirs and about 1,000 small dam reservoirs. Possessing 28 per cent of the country's water potential, the Euphrates–Tigris River basin is the largest basin in terms of both surface area and water potential. The Euphrates and the Tigris have their sources in the high mountains of north-eastern Anatolia and flow through Turkey before entering the Syrian Arab Republic. These two rivers account for approximately one third of the water potential of Turkey. Many rivers rise and discharge into seas within the country's borders. The rivers discharging into the Black Sea are the Sakarya, Filyos, Kızılırmak, Yeşilırmak and Çoruh. Meanwhile, the Asi, Seyhan, Ceyhan, Tarsus (Berdan) and Dalaman discharge into the Mediterranean Sea; the Büyük Menderes, Küçük Menderes, Gediz and Meriç into the Aegean and the Susurluk/Simav, Biga and Gönen into the Sea of Marmara.[6]

ELECTRICITY SECTOR OVERVIEW

Turkey could provide itself completely with self-produced energy. As of 31 December 2020, its total installed capacity stood at 95,890 MW compared to 69,516 MW in 2014.[7,8] The installed capacity increased thanks to the installation of new natural gas, solar power, hydropower and wind power plants. Within the energy mix, hydropower has become the primary source in Turkey, accounting for over 32 per cent of the installed capacity. As for the other energy sources, 27 per cent of installed capacity comes from gas-fired power plants, 21 per cent from coal-fired plants (hard coal and lignite), 9 per cent from wind power, 7 per cent from solar power, 2 per cent from other renewable sources (geothermal power and waste heat), 1 per cent from biomass and 0.3 from other fuels (oil, diesel, naphtha) (Figure 1). Thus, at the end of December 2020, the share of renewable energy in the country's total installed capacity exceeded 50 per cent.[7,8]

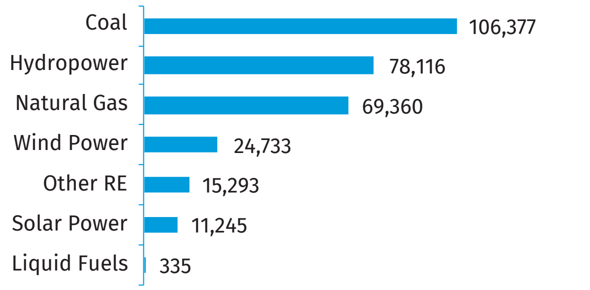
In 2020, total annual electricity generation in Turkey amounted to 305.5 TWh. Within total power generation, coal had the dominant role contributing almost 35 per cent, hydropower 26 per cent, natural gas 23 per cent, wind and solar power 12 per cent combined and geothermal power and biomass 3 and 2 per cent, respectively (Figure 2). Overall, roughly 58 per cent of electricity generation was obtained from fossil fuel sources and 42 per cent from renewable sources. In the same year, Turkey imported 1,888 GWh and exported 2,484 GWh of electricity.[7,8]

Figure 1. **Installed Electricity Capacity by Source in Turkey in 2020 (MW)**



Source: EMRA,[7] Chamber of Electrical Engineers[8]

Figure 2. **Annual Electricity Generation by Source in Turkey in 2020 (GWh)**



Source: EMRA,[7] Chamber of Electrical Engineers[8]

Compared to 2019, electricity generation in 2020 increased by 7.8 per cent and electricity consumption by 5.8 per cent. The share of the installed capacity and electricity generated from privately-owned plants has been rising steadily since 2006. While the share of the public sector in installed capacity was 60 per cent and that of the private sector 40 per cent in 2006, by 2020, the share of the private sector in installed capacity was 78 percent and that of the public sector 22 per cent, while in electricity generation the shares were 82 per cent and 18 per cent, respectively. More than half of electricity (57 per cent) is generated using domestic sources and the rest is from imported energy sources.[7,8] The electrification rate across the country is 100 per cent.

The Electricity Market Law No. 6446 (EML) introduced on 30 March 2013 is still the main law applicable to the Turkish electricity market. The EML regulates the obligations of all real persons and legal entities directly involved in the generation, transmission, distribution, wholesale supply, retail supply, import and export of electricity in the country. The implementation and interpretation of new mechanisms introduced by the EML are outlined in secondary legislation, among which the most notable piece is the Electricity Market Licensing Regulation (Licensing Regulation) published on 2 November 2013. The Licensing Regulation introduced a new licensing regime, intended to reform and stimulate the market.[9,10]

In Turkey, there are two main governmental authorities regulating the electricity market, the Ministry of Energy and Natural Resources (MENR) and the Energy Market Regulatory Authority (EMRA). The electricity market can be subdivided into the generation, transmission, market operation and distribution functions. Turkish Electricity Transmission Corporation (TEIAS) owns and operates the electricity transmission system, while distribution is divided into 21 separate regions. Each region is controlled by private distribution companies each with distribution licences issued by EMRA. EMRA is responsible for issuing licences to all electricity suppliers. There are 1,656 licensed generation companies, 21 private distribution companies operated by private sector, 21 assigned private suppliers with duty of last resort and one state-owned wholesaler Electricity Generation Company (EÜAŞ). The private sector plays an important role in the electricity market. The private sector's share in licensed installed capacity is approximately 80 per cent, including Build Operate Transfer (BOT) and Transfer of Operating Rights (TOOR) contracts.[11,12]

Before the introduction of the EML, TEIAS was both a system and market operator. Since 2018 however, TEIAS has operated solely as the transmission system operator (TSO), while a new company, the ISTANBUL ENERGY EXCHANGE (EPIAS), was established as a market operator. EPIAS's shareholders are represented by 30 per cent each by TEIAS and by Istanbul Exchange Market (BIST) and 40 per cent by the private sector. EPIAS, as the market operator, is responsible for organizing the energy exchange market operations and operates the spot market to allow the private sector to make forecasts more easily in order to plan their investments.[13]

Turkey has been experiencing a rapid growth of demand in all segments of the energy sector for decades. Forecasts indicated that this trend will continue in the forthcoming decades in parallel with the economic and social development. The main target of the Turkish energy policy has been to provide timely, reliable and sufficient energy, meeting the rapidly growing demand, at affordable prices and in an environmentally sound manner.[14] In 2017, Turkey announced the National Energy and Mining Strategy to strengthen the confidence in the industry and to update the country's goals for the sector. Ensuring energy supply security and predictable market conditions as well as localization are the three pillars of strategy in this sector. Thus, Turkey aims to promote the use of domestic energy resources and reduce import dependency. As part of this effort, the 11th Development Plan (2019–2023) sets out targets to achieve 219.5 TWh of electricity production from domestic resources, based on total electricity demand of 375.8 TWh, by 2023. As part of this projection, Turkey plans to commission 10,000 MW each of solar and wind power capacity in 2017–2027.[12]

As of January 2021, electricity prices per kWh in Turkey were USD 0.094 for household consumers, USD 0.13 for commercial enterprises and USD 0.11 for industrial enterprises.[15]

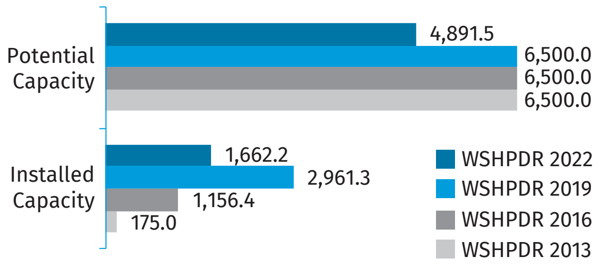
Figure 4. **Distribution of Small Hydropower Plants in Turkey by Province**

Source: DSI[16,17]

SMALL HYDROPOWER SECTOR OVERVIEW

Although there is no legal definition in Turkey, hydropower plants with an installed capacity of less than 10 MW are widely considered as small hydropower (SHP). As of the end of 2020, there were 351 SHP plants in operation. Of these, 14 are operated by the DSI and 337 are operated by the private sector. The installed capacity of the operating SHP plants is 1,662.2 MW, their total generation potential is 6,279,926 GWh/year. A further 38 SHP plants were under construction at the end of 2020 (Table 1).[16] In addition, 613 SHP projects with a combined installed capacity of 2,594.3 MW and generation potential of 8,569,956 GWh/year were cancelled. These cancellations were due to a number of factors, including: technical and economic difficulties, challenges associated with obtaining licences and other necessary planning permissions, and environmental factors such as drought. The decrease in installed capacity since the *World Small Hydropower Development Report (WSHPDR) 2019* is due to access to new and updated datasets (Figure 3). The decrease in potential capacity is due to new economic potential estimates from State Hydraulic Works.[16,17]

Figure 3. Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Turkey (MW)



Source: DSI,[16,17] *WSHPDR 2013*,[17] *WSHPDR 2016*,[18] *WSHPDR 2019*[19]

Table 1. **Overview of Small Hydropower in Turkey as of December 2020**

Stage of project	*Owner (public/private)*	*Number*	*Installed capacity (MW)*	*Generation potential (GWh/year)*	*Share of total (%)*
Operational	DSI (public)	14	42.57	145,100	0.9
	Private	337	1,619.63	6,134,826	35.8
	Total	351	1,662.20	6,279,926	36.7
Under construction	DSI (public)	19	101.83	368,389	2.2
	Private	19	101.83	368,389	2.2
	Total	38	202.66	736,778	4.4
Inspection and feasibility study	Private	70	355.98	1,229,931	7.7
	DSI (prelicence -Planned)	6	31.19	94,290	0.3
	Total	76	287.17	1,325,221	8.0
Total potential (operation-construction-inspection-project)		*476*	*2,297.16*	*8,493,338*	*49.9*
Cancelled SHP projects		613	2,594.29	8,569,956	50.1
Total SHP potential		**1,089**	**4,891.45**	**17,063,294**	**100**

Source: DSI[16,17]

Regionally, 34 per cent of SHP plants (120 plants) are located in the Black Sea region of the country; 21 per cent (74 plants) in the Mediterranean region; 16 per cent (55 plants) in the Eastern Anatolia region; 14 per cent (48 plants) in the Central Anatolia region; 9 per cent (30 plants) in the Marmara region and 6 per cent (21 plants) in the Aegean region (Figure 4).[16,17]

Table 2 and Table 3 show lists of selected operational and ongoing SHP projects in Turkey, respectively.

Table 2. **List of Selected Operational Small Hydropower Plants in Turkey**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Eastern	Bingol	10.0	–	Nassan Electricity Generation	–
Boğazköy	Bursa	10.0	–	Burgüç Bursa Collaboration	2005
Yesilvadi	Hatay	10.0	–	Koçoğlu Construction Energy	2013
Balıklı 1, 2 & 3	Artvin	9.8	–	Assu Electric Energy Generation	–
Sölperen	Erzincan	9.8	–	Vasfi Energy	2013 (?)
Kuyma	Samsun	9.7	Run-of-river	Kuyuma Elk. Ürt. A.Ş.	2020
Kıran	Giresun	9.7	–	Arsan Energy	–
Adasu	Sakarya	9.6	–	Sakarya Metropolitan Municipality	2013 (?)
Kale	Rize	9.6	–	Bahser Energy	2010
Berke	Kastamonu	9.4	–	Elbi Energy	2014
Hasanlar	Duzce	9.3	Dam	Batıçim Energy	2011
Esendurak	Erzurum	9.3	–	Meral Electricity Generation	2012
Alicik I-II	Rize	9.0	Run-of-river	Baro Elektrik Üretim A.Ş.	2020
Çarıklı	Amasya	9.0	–	Delta Investment Holding	–
Telli	Giresun	8.7	–	Bahser Energy	2012
Karakuş	Adıyaman	8.2	Run-of-river	Murat HES Enerji Elektrik Üretim ve Tic. Ltd. Şti.	2020
Kirazlıköprü	Bartın	8.0	Dam	MHM Turkey Makine Tic. Ltd. Şti.	2020
Kuzkaya	Kastamonu	6.5	Run-of-river	Murat Kaan Elektrik Üretim A.Ş.	2020
Hacımercan	Sakarya	5.4	Irrigation channel	Akım Enerji A.Ş.	2020
Araklı Kaçkar	Trabzon	3.9	Run-of-river	İpek Enerji San. ve Tic. Ltd. Şti.	2020

Source: Enerji Atlas[20]

The total hydropower potential of Turkey is estimated at 55,000 MW. According to MENR's Strategic Plan 2019–2023, by 2023 installed hydropower capacity is to reach 32.9 per cent of the country's total installed capacity (approximately 32 GW).[14,22]

Table 3. **List of Selected Ongoing Small Hydropower Projects in Turkey**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Developer*	*Planned launch year*	*Development stage (% completed)*
Kutay	Tokat	7.05	Run-of-river	Arc Elektromek. Enerji San. ve Tic. Ltd. Şti.	N/A	85
Bingöl I	Bingöl	7.75	Run-of-river	Ant Karlıova Elk. En. Ürt. Ltd. Şti.	2022	70
Düzköy	Trabzon	6.12	Run-of-river	ADV Elk. Ürt. Ltd. Şti.	2021	45
Zilan	Van	6.07	Run-of-river	Zilan Elektrik Üretim A.Ş.	2021	22
Adadağı	Giresun	7.17	Run-of-river	Değirmenyanı Enerji Üretim Ticaret A.Ş.	2020	10

Source: DSI[21]

Table 4. **Hydropower Status in Turkey as of 31 December 2020**

Stage of project	*Owner (public/private)*	*Number*	*Installed capacity (MW)*	*Generation potential (GWh/year)*	*Share of total (%)*
Operational	DSI (public)	68	13,766	48,952	27.2
	Private	646	17,625	59,053	32.8
	Total	714	31,391*	108,005	50
Under construction	DSI (public)	2	700	2,569	1.4
	Private	35	579	2,009	1.1
	Total	37	1,279	4,578	1.5
Inspection and feasibility study	Private	210	8,120	21,680	12.0
	DSI (prelicence-planned)	42	1,574	4,704	2.6
	Total	252	9,194	26,384	14.6
Total potential (operation-construction-inspection-project)		1,003	41,864	138,967	77.1

Source: DSI[16]

Note: *the discrepancy with between these data and Figure 1 is due to the different sources.

Through public-private cooperation, 714 hydropower plants (public and private) with an installed capacity of 31,391 MW and a power generation potential of 108 TWh have been completed and put into service (Table 4). Construction of public sector SHP projects is carried out by DSI (State Hydraulic Works) and the operation is then transferred to EÜAŞ. For SHP projects developed and constructed by the private sector, except for those with an EMRA licence, the DSI may be responsible for a combination of the following: water use agreements, project coordination, construction, water structures acceptance, etc.[23]

RENEWABLE ENERGY POLICY

Turkey is very rich in hydropower, geothermal, solar and wind power resources. Accordingly, development of renewable energy in Turkey is highly encouraged. The national 2023 targets for renewable energy according to national energy policies and strategy documents are as follows:

- In the 11th Development Plan (adopted in 2019), to increase the share of renewable energy sources in total electricity generation to 38.8 per cent.[23]
- In the National Energy and Mining Policy Document (adopted in 2017), to increase electricity generation from renewable energy sources to at least 30 per cent.[12,24]
- The goals of MENR for the year 2023 in the 2019–2023 Strategic Plan included the following:
  - Wind energy installed capacity target is 11,883 MW;
  - Solar energy installed capacity target is 10,000 MW;
  - Hydropower installed capacity target is 32,037 MW;
  - Geothermal and biomass installed capacity target is 2,884 MW.

The set targets for the share of renewable energy in total electricity generation have already been exceeded.

The support mechanism available for renewable energy projects in Turkey is called YEKDEM. It started to be implemented in 2011.[25] Currently, power plants built from 2005 (when the Law on Renewable Energy Sources 5346 was issued) to 2021 can apply for the mechanism. The mechanism consists of two parts: the feed-in tariff (FIT) prices based on the type of renewable energy and the additional FIT price related to locally manufactured equipment usage. These prices are 73 USD/MWh for wind power and hydropower, 133 USD/MWh for solar power and biomass and 105 USD/MWh for geothermal power.[26]

To participate in the YEKDEM scheme, developers must apply to the EMRA after the commissioning of the project in October for following year and cannot quit the mechanism in the year which they applied for. There is no obligation to participate in the mechanism. Projects which are commissioned before 30 June 2021 can benefit from YEKDEM for 10 years.[27] On 30 January 2021, the President's Decision No. 3453 extended the YEKDEM support mechanism for renewable energy-based electricity generation projects for the period from 1 July 2021 to 31 December 2025.[28] Accordingly, the new YEKDEM prices will be 0.40 TL/kWh (0.046 USD/kWh) for hydropower, 0.32 TL/kWh (0.037 USD/kWh) for wind and solar power and 0.54 TL/kWh (0.062 USD/kWh) for geothermal power.[29]

The local content support, which is provided for in Law No. 5346 and may be considered as an extra bonus, is added to the YEKDEM prices of the relevant renewable energy generation plant. This additional tariff is provided for a term of five years from the starting date of operation.[25,28]

Designated forested areas, land privately owned by the Treasury or land under the disposal of the state in its entirety can be utilized for the purposes of renewable energy generation if permission is granted by the Ministry of Agriculture and Forestry or the Ministry of Treasury and Finance. Renewable energy generation plants are not charged the Forestry Peasant Development Revenue or the Forestation and Erosion Control Revenue. Permission, lease, easement and usufruct permission fees are discounted by 85 per cent for renewable energy generation projects during the initial 10 years of investment and operation of power transmission lines, including those in operation. Pursuant to Provisional Article 4 of the Electricity Market Law No. 6446, for all types of generation plants (including renewable energy ones) that will be operational by 31 December 2025, transmission system usage fees are discounted by 50 per cent for the first five years of operation. Additionally, pursuant to Article 43.4 of the Electricity Licensing Regulation, for the power plants generating electricity from local natural resources and renewable sources, the licence holders are not required to pay the yearly licence fees for the first eight years following the date of completion of the power plants.[30]

Under the Renewable Energy Resources Zone (REZ/YEKA) model, which defines the process of Renewable Energy Zones where fixed capacity is tendered, by 2021, 2,000 MW of wind power capacity and 1,000 MW of solar power capacity competitions had been completed. Additionally, in March 2021 the small-scale REZ method was implemented for solar power for the first time. Within this framework, it is decided to hold 74 separate REZ competitions in 36 provinces with 10 MW, 15 MW and 20 MW capacities on auction. The total competition capacity will be 1,000 MW, with 709 applications for solar tenders received in March 2021.[31]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The realization of SHP projects starts with a study process. The Hydroelectric Energy Department studies the feasibility reports for planned hydropower projects and, taking their rentability into consideration, posts the economically feasible ones on its website for a bid meeting. The applicant companies submit the required documents to DSI and are afterwards invited to a DSI meeting in order to bid.[32] After the meeting, the company that will carry out the project is decided. In the next process, the company prepares a detailed feasibility report and submits it to DSI for approval. After the completion of the process of an environmental impact assessment, a water usage rights agreement between DSI and the company is signed and the developer moves to the construction phase. Throughout the construction phase, the Hydroelectric Energy Department supervises the project. After the completion of the project, the Hydroelectric Energy Department with some other DSI departments makes a pre-final inspection.[16,33] If the plant passes that inspection, it is commissioned and will be granted permission to generate electricity (Figure 5).[17]

Small-scale power plants using renewable sources up to 5 MW and micro-co-generation plants have been exempted from obligations for receiving a licence and establishing a company.[30]

COST OF SMALL HYDROPOWER DEVELOPMENT

An average run-of-river hydropower plant costs USD 1.5 million per MW of installed capacity. Price per unit of generation varies tremendously due to very different precipitation regimes in different parts of the country.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Private developers of SHP projects are responsible for finding the required capital for the investment and can use finance options offered by banks. After the commissioning of a plant, the Government offers a fixed purchase price for electricity under the YEKDEM mechanism.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Changes in natural water circle caused by climate change have had and will have impact on hydropower generation. The effect of climate change on SHP is mostly influenced by the change in the river runoff, with the changes in precipitation and temperature being the key driving factors. The increase in the frequency of extreme weather events will also create pressures on hydropower production.[34,35]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Over the past years, installed SHP capacity in Turkey has steadily increased. However, SHP still has to face barriers of different types:

- Legal: Renewable Energy Law No. 5346 applies to SHP or hydropower plants with a reservoir area of less than 15 km^2, making no limitation regarding installed capacity. This guideline encourages the private sector to move towards investment in large hydropower projects for potentially higher profits;
- Environmental: Turkey is among the countries most affected by climate change and variability. As a result, SHP investments are adversely affected due to the decrease in surface waters;
- Social: public opinion against hydropower could affect the investors, due to wrong or inappropriate site selection, exclusion of stakeholders and unplanned basin management.

The following points summarize the main enablers for SHP development in Turkey:

- A pre-existing SHP sector;
- Institutional support for the sector.

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Figure 5. **Process of Hydropower Project Realisation in Turkey**

Source: DSI[17]

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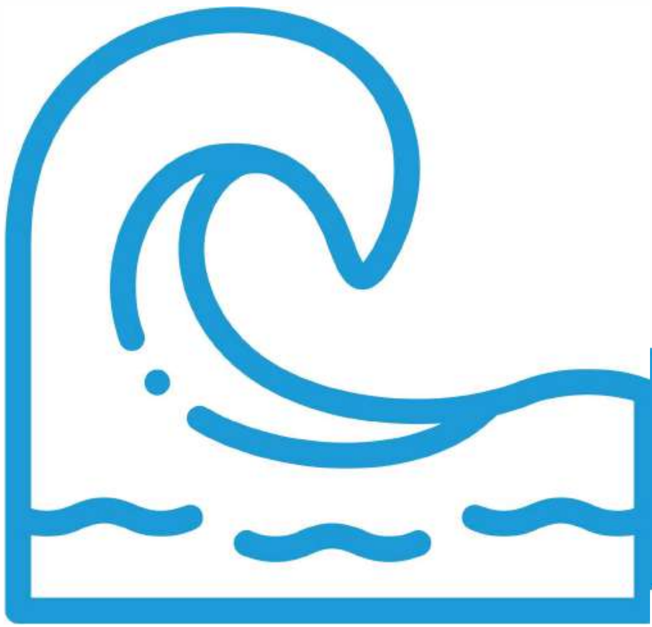


4. Europe

4.1. Eastern Europe

Countries: Belarus, Bulgaria, Czech Republic, Hungary, Moldova, Poland, Romania, Russia, Slovakia, Ukraine

INTRODUCTION TO THE REGION

The countries of Eastern Europe include six member states of the European Union (EU) – Bulgaria, the Czech Republic, Hungary, Poland, Romania, and Slovakia, as well as four non-member states – Belarus, Moldova, Russia and Ukraine. Moldova and Ukraine are members of the Energy Community and are taking steps to unify the legislative framework governing their energy sectors with that of the EU. The electricity grids of the EU member states are interconnected through the ENTSO-E network of transmission operators, which also includes parts of the electricity grid of Ukraine. Significant interconnections additionally exist between Ukraine and Moldova, as well as between Russia and Belarus.

The generation of electricity in Eastern Europe is dominated by thermal power and nuclear power, with the latter present in the energy mix of every country in the region with the exception of Poland and Moldova and accounting for the largest share of annual generation in Slovakia, Hungary and Ukraine. Hydropower and other renewable energy sources (RES) play an important supplementary role in Eastern Europe. Wind power and solar power are used widely but account for a relatively small share of total generation. Poland leads the region in wind power capacity and Ukraine has the region's largest solar power capacity. The region's largest electricity producer is Russia, which sources most of its generation from thermal power, nuclear power and hydropower.

Hydropower is present in the energy mix of every country in Eastern Europe, but in most countries in the region its role is secondary to that of other energy sources. Russia is the region's largest hydropower producer by both installed capacity and annual generation, but hydropower is outpaced in the country by thermal and nuclear power in terms of its share of annual generation. In Slovakia, hydropower is the leading energy source in terms of installed capacity, but accounts for a significantly smaller share of generation than nuclear power. The contribution of hydropower to the energy mix of Belarus, Hungary and Moldova is relatively small. An important issue facing hydropower in Eastern Europe is the age of existing dams and hydropower infrastructure, many of which were built decades ago and increasingly carry the risk of leakage or failure.

An overview of the electricity sectors of the countries in the region is provided in Table 1.

Table 1. **Overview of Eastern Europe**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Belarus	9	100	100	11,280	38,179	96	400
Bulgaria	7	100	100	12,839	39,466	3,213	3,000
Czech Republic	11	100	100	21,350	81,444	2,265	3,437
Hungary	10	100	100	9,202	34,154	58	219
Moldova	3	100	100	2,999	4,289	62	147
Poland	38	100	100	49,238	152,308	2,356*	2,698
Romania	19	100	100	18,538	53,000	6,642	15,400
Russia	147	100	100	245,313	1,047,000	49,912	207,416
Slovakia	5	100	100	7,716	29,010	2,544	4,871
Ukraine	44	100	100	54,365	153,800	6,300	7,800
Total	-	-	-	**432,840**	-	**73,448**	-

Source: *WSHPDR 2022*[1]

Note: *Includes only public hydropower. Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The most common definition of small hydropower (SHP) in Eastern Europe includes plants of up to 10 MW, and is adhered to by Belarus, the Czech Republic, Romania, Slovakia and Ukraine. In Hungary, the up to 5 MW definition is used. Russia adheres to the up to 30 MW definition for regulatory purposes but occasionally uses the up to 25 MW definition for the purpose of strategic planning and incentivization of hydropower development. There is no official definition of SHP in Bulgaria, Moldova or Poland.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Eastern Europe (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Belarus	Up to 10 MW	17.3	250.0	17.3	250.0
Bulgaria	N/A	N/A	N/A	494.7	580.7
Czech Republic	Up to 10 MW	353.0	465.0	353.0	465.0
Hungary	Up to 5 MW	17.1	28.0	17.1*	28.0*
Moldova	N/A	N/A	N/A	0.3	7.2
Poland	N/A	N/A	N/A	291.7	1,500.0
Romania	Up to 10 MW	321.0	730.0	321.0	730.0
Russia	Up to 30 MW	852.9	825,844.6	168.4	168.4**
Slovakia	Up to 10 MW	81.6	145.0	81.6	145.0
Ukraine	Up to 10 MW	119.6	280.0	119.6	280.0
Total	-	-	-	**1,864.7**	**4,154.3**

Source: *WSHPDR 2022*[1]

Note: *Based on the local definition of SHP. **Based on installed capacity of SHP up to 10 MW.

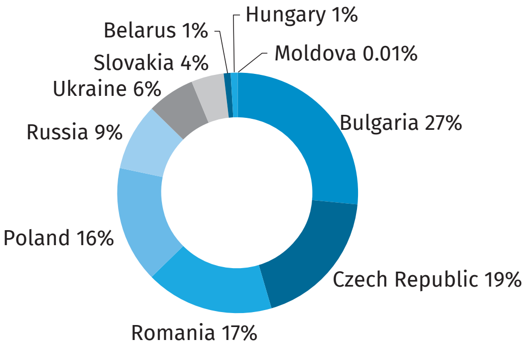
The installed capacity of SHP up to 10 MW in Eastern Europe is 1,864.7 MW, while potential capacity is estimated at 4,154.3 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the total installed capacity decreased by 2 per cent, largely due to a re-assessment of actual capacities of existing SHP plants in Romania by the national energy regulator, although the installed SHP capacities of several other countries increased. The potential capacity of SHP of up to 10 MW in the region decreased by nearly 5 per cent on the basis of more recent assessments of the SHP potential of Slovakia and Ukraine.

SHP has a long history in Eastern Europe. The first plants in the region were constructed in the 1880s, and some continue to operate today after successive refurbishments and upgrades. The first half of the 20th century saw a very large number of plants constructed across the region. Subsequently, some countries in Eastern Europe shifted towards highly centralized electricity generation and many SHP plants were abandoned or fell into disrepair. In the last few decades, some revival of the SHP sector has been observed, which in several countries in the region has been driven largely by private investors seeking to take advantage of liberalized electricity markets and renewable energy subsidies. Some new SHP construction has taken place at previously abandoned sites, which are common across the region. However, the recent proliferation of privately-run SHP plants has generated significant controversy in several countries, particularly in light of increasing seasonal variability in water levels. Additionally, the ageing of existing plants has contributed to decreases in available capacity.

In the last few years, significant construction of new SHP plants has mainly occurred in the Czech Republic, Poland and Ukraine, and to a lesser extent in Belarus, Russia and Romania. However, as the commissioning of new plants has coincided with the decommissioning or re-assessment of available capacity of older plants, cumulative installed capacities of several countries with active SHP development have actually decreased.

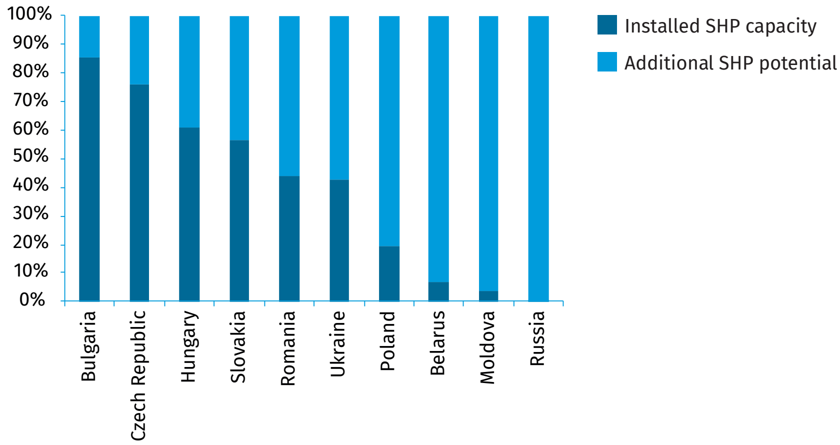
The national share of regional installed SHP capacity by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Eastern Europe (%)**



Source: *WSHPDR 2022*[1]

Figure 2. **Utilized Small Hydropower Potential by Country in Eastern Europe (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP of up to 10 MW except in the case of Russia, where the local definition is used due to a lack of data on the potential capacity for SHP of up to 10 MW.

Belarus has an installed capacity of 17.3 MW for SHP of up to 10 MW, provided by 49 plants. Potential capacity is estimated at 250 MW, indicating that approximately 7 per cent has been developed. Although several new mini-hydropower plants have been commissioned over the last few years, the overall installed capacity of the country has not increased as the capacities of previously existing plants have been re-assessed downwards. Thirty-four potential SHP sites have been identified in the country.

The installed capacity for SHP of up to 10 MW in **Bulgaria** is 494.7 MW, while potential capacity is estimated at 580.7 MW, indicating that 85 per cent has been developed. Little new SHP construction has taken place in the country in recent years, although a number of restoration and rehabilitation projects have been carried out on existing plants. There were several ongoing SHP projects in the country as of 2021.

The **Czech Republic** has an installed capacity of 353 MW for SHP of up to 10 MW, while potential capacity is estimated at 465 MW, indicating that 76 per cent has been developed. There are 1,422 SHP plants in the country, of which 953 are micro-scale plants with a cumulative capacity of 38 MW. Such plants make up the bulk of new SHP development in the country, and, while many new plants have been commissioned in recent years, their individual capacities have generally not exceeded several hundred kilowatts. There is a lack of comprehensive information on ongoing or planned SHP projects in the Czech Republic due to a degree of unwillingness on the part of private investors to disclose such information.

The installed capacity for SHP of up to 5 MW in **Hungary** is 17.1 MW provided by 28 plants. Potential capacity for SHP of up to 5 MW is estimated at 28 MW, indicating that 61 per cent has been developed. The estimate of potential capacity in Hungary has been re-assessed on the basis of economic feasibility of potential sites. The most recent SHP plant in the country was commissioned in 2017 and one other SHP plant was recently refurbished. There are no ongoing SHP projects or concrete plans for any additional SHP development.

Moldova has one operational SHP plant with an installed capacity of 0.25 MW. Potential capacity is estimated at 7.2 MW, indicating that nearly 4 per cent has been developed. A large number of formerly operational plants and abandoned SHP sites exist in the country, with as many as 17 plants operational in the 1960s. A significant part of the country's identified potential capacity comes from these abandoned or non-operational plants rather than greenfield sites. However, there are no specific plans or ongoing projects for additional development or refurbishment of SHP in Moldova at this time.

In **Poland**, the installed capacity of SHP of up to 10 MW is 291.7 MW, while potential capacity is estimated at 1,500 MW, indicating that 19 per cent has been developed. SHP development in the country is actively ongoing, with multiple plants commissioned between 2018 and 2020. A very large number of identified potential sites exist in the country, including thousands of historical sites such as former water mills and abandoned hydropower plants that could host potential SHP projects. A number of SHP projects are in the planning stages, to be commissioned in 2023.

The installed capacity of SHP of up to 30 MW in **Russia** is 852.9 MW, while the technically-feasible potential capacity is estimated at 825,845 MW, indicating that less than 1 per cent has been developed. The installed capacity of SHP of up to 10 MW is 168.4 MW, although no reliable estimate of potential capacity for SHP of up to 10 MW is available. Regionally, the North-Western and North Caucasus regions lead the country in installed SHP capacity, while the largest potential capacity is located in the Far Eastern region. Several new SHP plants have been constructed in recent years and several existing plants have been refurbished. Major renovation of approximately 40 SHP plants is planned for 2025–2026.

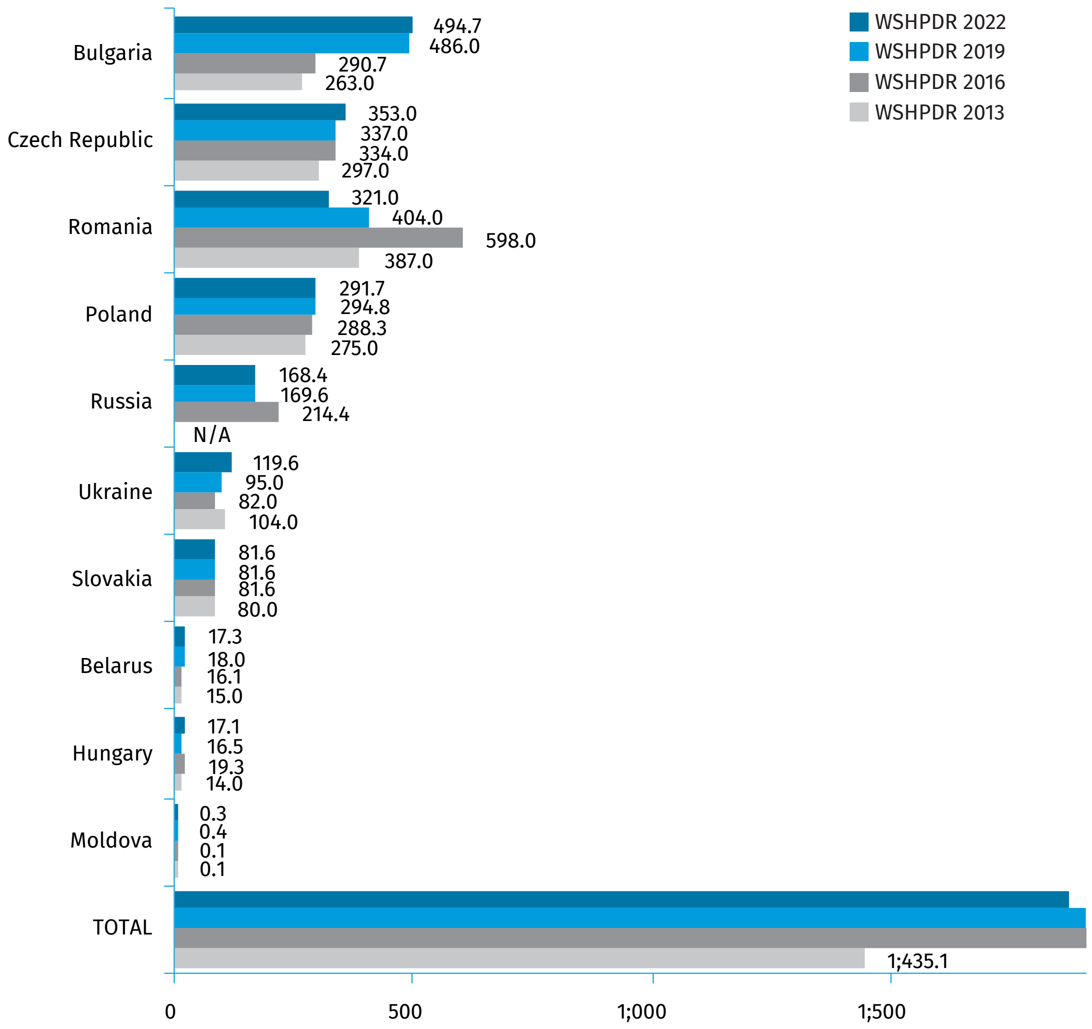
Romania has an installed capacity of 321 MW for SHP of up to 10 MW, provided by 103 plants. Potential capacity is estimated at 730 MW, indicating that approximately 44 per cent has been developed. SHP development in the country is ongoing with several new plants commissioned between 2017 and 2021, although the reported installed capacity of the country has decreased due to a reassessment of the actual capacities of existing plants.

Slovakia has an installed capacity of 81.6 MW for SHP of up to 10 MW, while potential capacity is estimated at 145 MW, indicating that approximately 56 per cent has been developed. There are 217 SHP plants operating across the country. Little SHP development has taken place in Slovakia over the last decade, with the most recent plant commissioned in 2014. An ambitious plan to develop an additional 160 MW of SHP capacity by 2030, proposed in 2011, has stalled due to environmental considerations. A more recent plan published in 2019 envisions a total SHP capacity of 145 MW to be achieved by 2030.

The installed SHP capacity of up to 10 MW in **Ukraine** is 119.6 MW provided by 167 plants. Potential capacity is estimated at 280 MW, reflecting the latest published data and representing a major decrease from previous estimates. These figures indicate that approximately 43 per cent of the total potential has been developed. SHP development in the country has been very active, with 15 new plants commissioned in 2019 alone. However, some of these projects were undertaken with insufficient oversight and have caused concern among locals and environmental activists. There are several ongoing and planned SHP projects in the country.

Changes in the installed SHP capacities of the countries in the region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower up to 10 MW from *WSHPDR 2013* to *WSHPDR 2022* by Country in Eastern Europe (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

Climate Change and Small Hydropower

A decrease in annual precipitation across most of the southern basins in Eastern Europe is projected by climate models, but no significant changes are expected in Hungary and in the Czech Republic. A recent study undertaken in Poland concluded that both positive and negative impacts on hydropower in the country are possible, depending on the climate change scenarios considered. Uneven precipitation distribution with wetter winters and more frequent droughts in the summer may negatively affect the viability of existing SHP plants and complicate planning and development of new SHP projects. In Ukraine and Moldova, additional river runoff regulations affecting farmland are expected to increase water use competition between SHP and irrigation. The SHP potential of Russia will likely benefit from climate change, but heavier precipitation is also expected to increase the risk of dam erosion and flooding of dam infrastructure.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main obstacles to SHP development in **Belarus** include the fact that the country's current and near-term electricity needs are met by the recent commissioning of new nuclear power capacities and the low hydropower potential in certain parts of the country due to the prevailing topography. However, potential opportunities for SHP development include the large number of formerly operational sites and the availability of detailed studies of SHP potential and development costs.

The majority of assessed SHP potential in **Bulgaria** is considered to be developed, and a lack of publicly available hydrological data hinders the planning of new projects. Additionally, regulatory barriers limit the construction of SHP in many potential locations and the country's local technical capacities in hydropower have declined over the last few decades. At the same time, SHP development in the country enjoys strong support in the form of feed-in tariffs (FITs) and can access a variety of funding opportunities from private commercial entities, public-private partnerships and international programmes.

Barriers to SHP development in the **Czech Republic** include regulatory obstacles, high operation and maintenance cost, a focus on other energy sources in strategic planning as well as political and social pushback against SHP. While some undeveloped potential remains in the county, the most promising sites have largely been developed. However, the SHP sector in the country benefits from FITs and other forms of support. Alongside the remaining undeveloped potential, there are opportunities in the refurbishment of existing plants.

Further SHP development in **Hungary** is unlikely in the near term as the country has prioritized the development of additional nuclear power capacity as well as that of non-hydropower RES, in particular solar power. Additionally, the most promising SHP sites in Hungary have already been developed. The main enabler of additional SHP development in the country is the remaining untapped potential.

The main barriers to additional SHP development in **Moldova** are a lack of financing as well as a lack of local technical expertise and manufacturing capacity in the SHP sector, requiring that most necessary equipment be imported at high cost. At the same time, there is substantial institutional support for SHP development in the country, including a comprehensive legal framework, subsidies and other support schemes. Demand for additional electricity in the country is high and could act as an additional incentive for investment in SHP.

Barriers to SHP development in **Poland** include regulatory and administrative barriers, high costs of operation (particularly with the adoption of new water pricing policies in 2018) and insufficient length of available support periods. Enablers include a robust FIT and feed-in premium (FIP) framework and a large number of identified potential sites on existing infrastructure.

Romania lacks support schemes for SHP and other RES, which alongside the high cost of water for power generation and complex licensing procedures discourages investors in the SHP sector. There is a lack of recent data on the country's SHP potential, and opposition to SHP development from environmental groups has posed an additional obstacle. The main enabler of SHP development in Romania is the country's significant untapped SHP potential.

In **Russia**, a lack of targeted state support for SHP, excessive regulatory requirements and a shortage of up-to-date scientific data on potential sites all act as constraints on SHP development. While the country has massive undeveloped SHP potential, much of it is located in hard-to-access areas with low population densities, making SHP projects in such locations economically unfeasible in most cases. However, support programmes do exist for small-scale power generation regardless of the energy source, which also apply to SHP, as well as support for RES facilities. The SHP sector in Russia is mature and relies on extensive local technical expertise and manufacturing capacity.

The main barrier to SHP development in **Slovakia** has been the concern over the impact of SHP on the environment and particularly on the ecological sustainability of rivers. Additional constraints include competition with other RES that generate a faster return on investment, as well as lengthy administrative procedures required for the approval of new projects. On the other hand, the SHP sector in the country benefits from several support schemes including FITs and green auctions, considerable potential remains untapped and there are specific plans for the expansion of the country's SHP capacity over the next decade.

Major barriers to SHP development in **Ukraine** include the limited hydropower potential in most parts of the country and increasing concerns over the environmental impact of SHP. Additionally, plant capacity factors have been steadily decreasing over the last decade due to falling water levels, putting into question the feasibility of some new and existing projects. One important enabler of SHP development in the country is the potential construction of SHP facilities on existing water supply infrastructure and outflow from industrial sites. Several such projects have already been realized and are generally well-received by the public.

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Belarus

Anastasiya Timashenok, Ministry of Energy of the Republic of Belarus

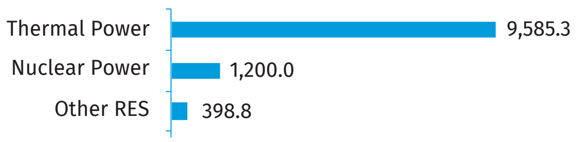
KEY FACTS

Population	9,349,645 (2021)[1]
Area	207,600 km^2[2]
Topography	The Republic of Belarus is a landlocked country. It is relatively flat and contains large tracts of marshy land. The highlands of the Belarusian Range run from the north-east to the south-west, with the highest peak at Mount Dzyarzhynskaya near Minsk, at 345 metres. Approximately 40 per cent of Belarus is covered by forest.[3]
Climate	The country lies in the transitional zone between the continental and maritime climates. In the winter, the climate is cold with average temperatures in January ranging from -4.5 °C in the south-west (Brest) to -8 °C in the north-east (Vitebsk). In the summer, the climate is cool and moist, with the highest temperatures in July at 18.5 °C.[4]
Climate Change	In the 20 years between 1989 and 2019, Belarus experienced 17 years with the highest average annual temperature since records began in 1881, with the average annual temperature exceeding the climatic norm by 1.3 °C.[5] As a consequence of rising temperatures, the northernmost agroclimatic region of Belarus has all but disappeared, while a new agroclimatic region has formed in the southern part of the country. Meanwhile, the increased unevenness of precipitation together with rising temperatures have also led to a two-fold increase in drought conditions in various parts of the country since 1992 relative to previous years, which has severely impacted agriculture. Extreme hydrometeorological phenomena such as unseasonal frosts, hailstorms, severe rainstorms and snowstorms as well as exceptionally strong winds have also increased in severity if not in frequency.[5,6] Long-term climate change models predict an increase in average monthly temperatures in Belarus of 0.6-1.9 °C over the period of 2010–2039 relative to the baseline period 1961-1990 and a further increase of 1.0-2.9 °C during the subsequent period of 2040–2069. Patterns of precipitation are also predicted to continue to shift, with the southern regions experiencing occasional droughts and the northern regions an excess of rainfall.[6]
Rain Pattern	Belarus receives an average annual precipitation of 600–700 mm, with extremes of 300 mm in dry years and 1,000 mm in humid years. Most precipitation falls during the warm season.[4]
Hydrology	There are approximately 20,800 rivers with a total length of 90,600 km, along with 10,800 lakes, 153 water reservoirs and 1,500 ponds. The country is divided into the Black Sea and the Baltic Sea basins. The former includes the Dnieper, Sozh and Pripyat Rivers and collects approximately 55 per cent of the runoff in the country. The latter includes the Western Dvina, Neman, Vilia and Western Bug Rivers and collects approximately 45 per cent of the runoff.[7]

ELECTRICITY SECTOR OVERVIEW

The total installed capacity in the Republic of Belarus amounted to approximately 10,074.0 MW in 2020 and increased to 11,280.0 MW by July 2021, following the commissioning of the first reactor of the Belarussian Nuclear Power Plant (Ostrovets NPP). Thermal power plants provided 9,585.3 MW (85 per cent) of the total capacity in 2021, including 8,800.2 MW of traditional thermal power and thermal power plants utilizing steam turbines as well as 785.1 MW provided by block power plants fuelled by non-renewable energy sources; nuclear power provided 1,200.0 MW (11 per cent); non-hydropower renewable energy sources (RES) provided 398.8 MW (4 per cent); and hydropower provided 95.9 MW (1 per cent) (Figure 1).[8,9,10]

Figure 1. **Installed Electricity Capacity by Source in Belarus in 2021 (MW)**

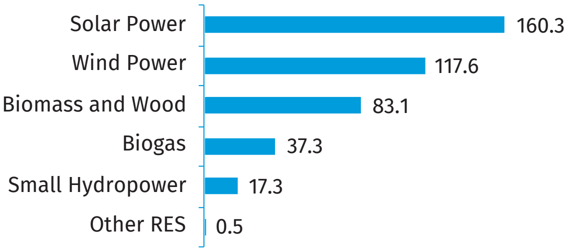


Source: Belenergo,[8] MoE,[9] Timashenok[10]

The total installed capacity of all RES in Belarus, including small hydropower (SHP) but excluding large hydropower, amounted to 416.1 MW in 2021. Of this total, solar power provided 160.3 MW (39 per cent), wind power 117.6 MW (28 per cent), biomass and wood 83.1 MW (20 per cent), biogas 37.3

MW (9 per cent), small hydropower 17.3 MW (4 per cent), and other RES 0.5 MW (less than 1 per cent) (Figure 2).[9,10]

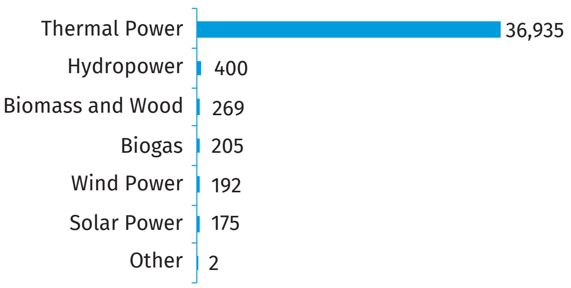
Figure 2. **Installed Renewable Energy Capacity by Source in Belarus in 2021 (MW)**



Source: Timashenok[10]

In 2020, total annual generation amounted to approximately 38,179 GWh, decreasing from 40,451 GWh in 2019. Thermal power from non-renewable sources provided 36,935 GWh (97 per cent) of the total in 2020, hydropower provided 400 GWh (1 per cent) and non-hydropower RES provided a combined total of 844 GWh (2 per cent), including 269 GWh from biomass and wood fuel, 205 GWh from biogas, 192 GWh from wind power, and 175 GWh from solar power, with other RES providing an additional 2 GWh (Figure 3).[10,11] Energy consumption in 2019 reached 38,113 GWh, and remained on roughly the same level in 2020 (approximately 38,020 GWh). Imports of electricity in 2019 equalled 32 GWh, while exports reached 2,370 GWh, representing a significant increase over previous years and continuing a shift from net energy imports to net electricity exports first observed in 2018. Imports in 2020 increased to 154 GWh, while exports decreased to 653 GWh.[8,10,11] The electrification rate in Belarus is 100 per cent.[12]

Figure 3. **Annual Electricity Generation by Source in Belarus in 2020 (GWh)**



Source: Timashenok[10]

The major player in the electricity sector in Belarus is the State Production Association Belenergo (SPA Belenergo), a state-owned company. In 2020 it operated 67 plants totalling 88 per cent (8,897.3 MW) of the installed capacity of Belarus and was responsible for 89 per cent (35.9 TWh) of all electricity generation in 2019 and 88 per cent (33.7 TWh) in 2020.[8,10] Belenergo is subordinate to the Ministry of Energy, with its objectives including the generation, transmission, distribution and sale of both electricity and heat. Belenergo works through a number of subsidiaries, which include six regional distribution companies and the Ostovets NPP. It additionally provides technical support and plays a leading role in initiating energy investment projects.[10]

Power plants utilizing RES in Belarus are primarily operated by private entities. The Ministry of Energy and Belenergo both implement measures to guarantee a connection of these privately owned plants to the state power grid as well as to guarantee the purchase by the state of all electricity generated by RES.[10,13]

The most significant recent development in the electricity sector of Belarus is the construction and commissioning of the Ostrovets NPP, the first nuclear power plant in Belarus, consisting of two reactors of 1,200 MW each. Construction of the plant is being carried out jointly with the Russian state company Atomstroyexport (ASE). The first reactor was connected to the grid in November 2020 and was granted an operating licence and put into commercial operation on 2 June 2021. The second reactor is expected to be commissioned in 2022. Once operating at full capacity, the plant is expected to generate 18 TWh annually, replacing 4.5 billion m^3 of natural gas per year.[10,14,15]

Electricity tariffs in Belarus can be divided into two general categories: single-rate and differentiated. The differentiated tariff rate depends on the time period of electricity consumption (minimum or maximum load). Additionally, tariffs for households are differentiated by the kind of stove installed on the property (gas or electric). Generally, prices for households are significantly lower than for other types of consumers (Table 1).

Table 1. **Electricity Tariffs in Belarus as of 01 January 2021**

Type of user	*Tariff in BYN/kWh (USD/kWh)*
Households	0.0374 – 0.4184 (0.0150-0.1600)
Industrial consumers: Basic fee — for capacity (for 1 month) Extra charge — for energy	26.7134 (10.3584) 0.2259-0.3297 (0.0876 – 0.1278)
Street lighting	0.3218 (0.1248)
Agricultural consumers	0.1406 – 0.2695 (0.0545 – 0.1045)
Transport	0.2606 (0.1011)
Charging stations for electric vehicles and hybrid electric vehicles	0.1269 – 0.1817 (0.0492 – 0.0705)

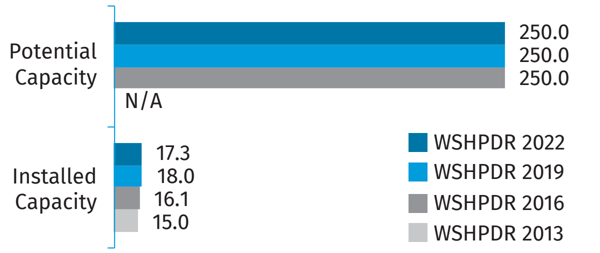
Source: Council of Ministers of Belarus,[16] Energosbyt[17]

Note: basic fee for industrial consumers charged per kW of connected capacity, rather than kWh.

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of SHP in Belarus is up to 10 MW. As of 2021, there were 49 SHP plants operating in the country with a total installed capacity of 17.3 MW. SPA Belenergo operates 21 SHP plants with a total installed capacity of approximately 9.5 MW, while the remaining plants are operated by local public entities and private companies. All operational SHP plants are connected to the national grid.[10,18] A list of the 20 most recently commissioned SHP plants is displayed in Table 2. Relative to the *World Small Hydropower Development Report* (*WSHPDR) 2019*, the installed capacity of SHP has decreased by approximately 4 per cent despite several additional SHP plants being commissioned since its publication, due to more accurate data becoming available. The estimate of economically feasible SHP potential remains 250 MW, as no new assessments have taken place since 2010 (Figure 4).[19]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Belarus (MW)**



Source: Timashenok,[10] Belnergo,[18] *WSHPDR 2019,*[19] *WSHPDR 2013,*[20] *WSHPDR 2016*[21]

Table 2. **List of Selected Operational Small Hydropower Plants in Belarus**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Sakovschina mini-HPP	Western Berezina River	0.225	Reservoir	Ministry of Agriculture and Food	1955/ 2008
Klyastitskaya SHPP	Nishya River	0.520	Reservoir	Belenergo	2008
Duboy mini-HPP	Dnieper-Bug Canal	0.330	Reservoir	Dnieper-Bug Water Route	2008
Voykovskaya mini-HPP	Dvinosa River	0.080	Reservoir	Minskmeliovodkhoz	2008
Kobrin mini-HPP	Dnieper-Bug Canal	0.200	Reservoir	Dnieper-Bug Water Route	2009
Sychevichskaya HPP	Rybchanka River	0.110	Reservoir	Minskmeliovodkhoz	2009
Zhodinskaya HPP	Pleesa River	0.030	Reservoir	Minskmeliovodkhoz	2009
Chizhovskaya HPP	Svisloch River (CHP-3 reservoir)	0.320	Reservoir	"Small Energy" LLC	2010
Drozdy HPP	Svisloch River (Drozdy reservoir)	0.300	Reservoir	"Small Energy" LLC	2010
Zaluz'ye HPP	Dnieper-Bug Canal	0.180	Reservoir	Dnieper-Bug Water Route	2011
Gavia HPP	Gavia River	0.190	Reservoir	"Umyastovsky" Cooperative	2011
Novosady SHHP	Dnieper-Bug Canal	0.223	Reservoir	Dnieper-Bug Water Route	2012
SHPP in Alexandria	Ulyanovka River	0.055	Reservoir	OJSC "Alexandriyskoe"	2012
Quarry "Gralevo"	Water intake of "Gralevo" quarry	0.700	Reservoir	JSC "Dolomit"	2014
SHPP "Stakhovo"	Dnieper-Bug Canal	0.692	Reservoir	Dnieper-Bug Water Route	2016
SHPP at "Verkhnee" reservoir	Lososyanka River	0.060	Reservoir	Grodnozhilstroy OJSC	2016
Slonimskaya mini-HPP	Issa River	0.200	Reservoir	HydroPark Ltd.	2017
Dobrush HPP	Iput River	0.450	N/A	Dobgidroinvest Ltd.	2019
Mnyuta HPP	Mnyuta River	0.160	Reservoir	HydroPark Ltd.	2019
Krupki SHPP	Bobr River	0.100	Reservoir	DobHydroInvest Ltd.	2020

Source: Timashenok,[10] Belenergo,[18] Batskalevich[22]

The development of SHP in Belarus has followed a pattern similar to that in other post- Soviet states. A large number of SHP plants were constructed in the immediate post-war period, with as many as 180 SHP plants operating in the country at the end of the 1950s.[23] However, most of these were decommissioned or abandoned in the subsequent decades as priorities shifted to large-scale power production and consumers previously dependent on electricity from SHP plants were gradually connected to the national grid.[24] During the period of 1990–2000s, a number of these plants were refurbished and put back into operation, while some of those still in operation were upgraded with new turbines.

In the last decade, little if any SHP development has taken place in Belarus and additional SHP development is not a priority for Belenergo at the moment. This position is tied in part to the construction and recent commissioning of the Ostrovets NPP.[10] Plans in 2010 included the construction of seven new, and the refurbishment of five existing, mini- and small hydropower plants, with a total potential capacity of 3.2 MW. However, the extent to which these plans have been realized is unclear.[23] One study conducted in 2011 surveyed potential new hydropower sites in Belarus and identified 34 SHP sites on 24 rivers and streams, with a total potential capacity of 72.85 MW, that can be considered environmentally and economically feasible for development. The study additionally estimated approximate development costs of each site per installed kW. A list of selected identified sites is displayed in Table 3.[25]

Table 3. **List of Selected Potential Small Hydropower Sites in Belarus**

Location	*Distance from river mouth (km)*	*Head (m)*	*Potential capacity (MW)*	*Area of reservoir (km²)*	*Cost (USD/kW)*
Dnepr River 1	1,410.0	5.6	9.21	115.3	2,742
Vilia River 1	279.2	9.7	8.89	11.0	549
Dvina River	8.5	9.7	7.75	8.4	623
Dnepr River 2	1,671.3	4.7	5.52	5.3	681
Berezina River	227.8	6.0	5.03	74.8	2,512

Source: Kalinin & Alferovich[25]

Table 4. **Tariffs for SHP plants**

Category/Period of Operation	*Price in BYN/kWh (USD/kWh)*
First 10 years after commissioning-	
Plants up to 300 kW:	0.244 (0.097)
Plants 301 kW - 2 MW:	0.229 (0.092)
Plants over 2 MW:	0.215 (0.086)
Between 10 and 20 years after commissioning:	0.129 (0.052)
More than 20 years after commissioning:	0.129 (0.052)

Source: Energosbyt,[17] MART[30]

Note: Tariffs apply to plants issued quota allotments between 1 November 2019 and 31 December 2020 and commissioned between 1 January 2020 and 31 December 2023.[30]

RENEWABLE ENERGY POLICY

The main principles guiding the development of RES in Belarus in recent years were outlined in the Law of the Government of the Republic of Belarus of December 27, 2010 No. 204-Z on Renewable Energy Sources. The primary objective of the act was to diversify the sources of electricity generation by 2020. Stipulations of the law, which remains in force, include guaranteeing the connection of electricity producers from RES to the national grid as well as the purchase of all electricity produced from RES by the state, while obligating the producers to meet certain technical requirements and to cover the costs of connection.[13]

In 2011, Resolution No. 836 of the Council of Ministers established the procedure for running the state cadastre of RES. In 2015, several additional legal acts related to RES entered into force, including Decree of the President of the Republic of Belarus No. 209 of 18 May 2015 on the Use of Renewable Energy Sources (later replaced by Decree of the President of the Republic of Belarus No. 357 of 24 September 2019) and Resolution of the Government of the Republic of Belarus No. 662 of 6 August 2015, which were called to regulate the procedure of the establishment and allocation of quotas for RES power plants.[26,27,28,29]

Tariffs paid to producers of electricity from RES by the state purchaser are set by the Ministry of Antimonopoly Regulation and Trade (MART), the most current resolution being MART Resolution No. 73 from 3 September 2018, along with its revisions in Resolutions No. 70 from 26 August 2019, No. 87 from 31 October 2019 and No. 62 from 24 September 2020. Tariffs are allocated according to the RES type, date of quota allocation and date of commissioning of the plant. A coefficient allocated based on these factors is applied to the baseline price, set to equal the current cost of electricity for industrial consumers with connected capacity of below 750 kVA, to form the final tariff.[30] Table 4 displays the current tariffs for newly-constructed SHP plants.

COST OF SMALL HYDROPOWER DEVELOPMENT

Prior studies have identified a range of sites in Belarus suitable for the construction of new SHP plants, with an estimated cost range of between 558 and 2,742 USD/kW. The SPA Belenergo programme for the construction and refurbishment of hydropower plants until 2020, adopted in 2003, provided for the construction of new SHP plants of no less than 100 kW capacity and with a cost of no more than 2,000 USD/kW.[25] Other assessments have set an upper limit of 2,750 USD/kW as economically feasible in the context of Belarus.[24]

New SHP plants constructed in Belarus in the last 15 years have carried price tags somewhat exceeding the upper limits discussed above. The Soligorsk SHP plant on the River Sluch' with an installed capacity of 150 kW, commissioned in 2007, cost 1.24 billion BYN (576,744 USD), or 8.30 million BYN/kW (3,845 USD/kW).[24] Meanwhile, the total cost of the Stakhovo SHP plant on the Dnieper-Bug Canal with an installed capacity of 630 kW, commissioned in 2015 and equipped with turbines manufactured in Austria, reached approximately 33 billion BYN (2,062,500 USD), or approximately 52 million BYN/kW (3,274 USD/kW).[31]

EFFECT OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Shifts in the distribution of precipitation across Belarus, forecast by climate models for the period of 2010–2069, may negatively affect the viability of SHP plants operating in the southern part of the country, where a decrease in precipitation is expected in the coming decades.[6] Additionally, regional changes in the distribution of runoff in the transboundary Neman (Niemen) River basin forecast for the period of 2021–2050 may see the part of the basin within the boundaries of Belarus experiencing an up to 20 per cent decline in runoff relative to the 1961–1985 baseline period. Conversely, the sections located in Russia and Lithuania may experience a corresponding 20 per cent increase.[32] Such a substantial decline in runoff can be expected to negatively impact existing SHP plants and undermine the viability of future SHP development on rivers located in the basin, including the Neman but also the Vilia, Strana, and Shyara Rivers.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The primary obstacles for the further development of SHP in Belarus include the following:

- The electricity needs of the country being largely met by existing capacities and development of future capacity targeted towards export, with efforts to reduce the dependence of Belarus on fossil fuel imports prioritizing nuclear power development;
- Low hydropower potential in the northern and central parts of the country due to the prevailing topography;
- Cost of new SHP development often in excess of what is deemed economically appropriate for Belarus;
- All other RES receiving higher initiation incentives in the RES tariff pricing structure than SHP;
- Threats to the viability of SHP in certain parts of the country due to climate change.

Possible enablers for SHP development in Belarus include the existence of a large number of decommissioned SHP plants in various stages of disrepair, some of which could potentially be refurbished, as well as the publication of prior studies mapping SHP potential and cost.

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Bulgaria

Dimitar Kisliakov, University of Architecture, Civil Engineering and Geodesy (UACEG)

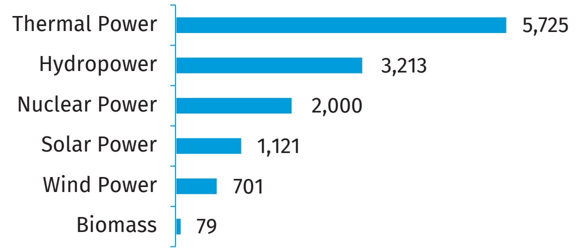
KEY FACTS

Population	6,916,548 (2020)[1]
Area	110,372 km^2 [2]
Topography	The topography of Bulgaria is composed of 31 per cent of lowlands (0–200 metres), 41 per cent of hills (200–600 metres), 25 per cent of highlands (600–1,600 metres) and 3 per cent of mountains (above 1,600 metres).[3] The country exhibits significant topographic variety, with three basic physical divisions running east to west: Northern Bulgaria, defined by the Danubian Plain and the Balkan Mountains; Southern Bulgaria, which includes the Rila Rhodope Massif; and a transitional area in between. The Balkan Mountains reach a height of 2,376 metres at Mount Botev, while the average elevation is 722 metres. The major mountain ranges in Southern Bulgaria include the Rhodope Mountains rising to 2,190 metres, the Pirin Mountains peaking at 2,914 metres and the Rila Mountains, which include the Musala Peak at 2,925 metres, the highest point in the country.[2]
Climate	The five climatic zones of Bulgaria include the moderate continental, intermediate, continental-Mediterranean, maritime and mountainous zones, determined by latitude, topography and distance from the Black Sea, which exerts a moderating influence on the coastal climate. Winters are coldest along the Danube River and mild in the valleys in the southern part of the country along the borders with Greece and Turkey. Summers are hot and dry, owing to the Mediterranean influence. Average monthly temperatures vary from -10.9 °C to 3.2 °C in January and from 5.0 °C to 25.0 °C in July. Temperatures above 35 °C are occasionally recorded in the towns of Rousse and Silistra.[3]
Climate Change	A warming trend has been observed in Bulgaria since the middle of the 1980s. Since 1997, all annual temperature anomalies have been positive, with 2007 experiencing the highest average annual temperature since records began, exceeding the average for the 1961–1990 period by 1.6 °C. Climate change projections for countries on the Balkan Peninsula, including Bulgaria, indicate an increase of 5–8 °C in air temperature during the summer season by 2080, relative to 1961–1990, while the number of summer days is expected to increase by up to 90 days. Air temperatures in the mountains are projected to increase by 2.8–3.2 °C by 2065–2094, relative to the period 2001–2011.[3]
Rain Pattern	The average annual precipitation in Bulgaria is 608 mm, ranging from approximately 450 mm in the north-east to more than 1,190 mm in the mountains. The lowland areas experience snowfall from mid-October to mid-May, with an annual average of 25–30 days of snow cover, while hailstorms occur between May and August.[2,4]
Hydrology	The major rivers internal to Bulgaria include the Maritsa, Iskŭr, Struma, Arda, Tundzha and Yantra, fed by meltwater from the snowfields of the Rhodope, Rila and Pirin Mountain Ranges. The Danube defines the northern border with Romania. Bulgaria has a complex drainage network dominated by relatively short rivers, with more than half the runoff draining into the Black Sea and the rest flowing into the Aegean Sea. In addition, several hundred lakes of glacial origin are present in the country.[2]

ELECTRICITY SECTOR OVERVIEW

In 2020, the total installed capacity in Bulgaria was approximately 12,839 MW. Of this total, thermal power provided 5,725 MW (45 per cent), including 4,365 MW from coal-fired plants and 1,360 MW from gas-fired plants, hydropower provided 3,213 MW (25 per cent), nuclear power 2,000 MW (16 per cent), solar power 1,121 MW (9 per cent), wind power 701 MW (5 per cent) and biomass 79 MW (less than 1 per cent) (Figure 1).[5]

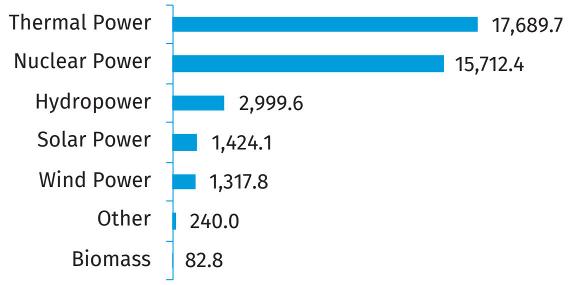
Figure 1. **Installed Electricity Capacity by Source in Bulgaria in 2020 (MW)**



Source: ESO[5]

Gross electricity generation in 2019 amounted to 39,466.3 GWh, with thermal power (coal and natural gas) accounting for 17,689.7 GWh (45 per cent of the total), nuclear power for 15,712.4 GWh (40 per cent), hydropower for 2,999.6 GWh (8 per cent), solar power for 1,424.1 GWh (4 per cent), wind power for 1,317.8 GWh (3 per cent) and biomass and other sources for 322.8 GWh combined (approximately 1 per cent) (Figure 2).[6] Nuclear power still has a decisive role in electricity generation in the country, along with thermal power, despite the recent decommissioning of four 440 MW reactors of the Kozloduy nuclear power plant, with two 1,000 MW reactors remaining in operation. Hydropower, despite its relatively large installed capacity, is employed primarily in a supporting role for providing power during periods of peak demand. The share of run-of-river plants in the total installed capacity is small, with the majority belonging to large reservoir plants on regulated water sources and pumped-storage plants.

Figure 2. **Annual Electricity Generation by Source in Bulgaria in 2019 (GWh)**



Source: EWRC[6]

Access to electricity in Bulgaria was 100 per cent as of 2019, as it has been for decades.[7] Electricity consumption in 2019 amounted to 37,628 GWh, exports reached 9,822 GWh, while imports amounted to 4,026 GWh.[6] The reliability of power supply has recently improved due to the changes made in the electricity system management.

The national Electricity System Operator EAD (ESO EAD) is an independent commercial company whose main functions include the operational management of the electricity system of Bulgaria, the implementation of joint work with the electricity systems of other countries, administration of the electricity market and of the balancing energy market, as well as the technical operation and maintenance of the country's electricity transmission network, which is divided into 13 network areas.[8] The total length of the power lines serviced by ESO EAD is over 15,000 kilometres. The ESO EAD supports 288 transformer substations and 5 hub substations. Thirty-two of the substations operated by ESO EAD have a total transformer capacity of over 15,000 MVA. Prior to 2015, ESO EAD was part of the structure of the National Electricity Company EAD (NEK EAD), but that year it was certified as an independent operator of the electricity transmission network. ESO EAD is an active member of the European association for the cooperation of transmission system operators (TSOs) for electricity (ENTSO-E).

The state-owned Natsionalna Elektricheska Kompania EAD (NEK EAD) is the successor to the state-owned energy producer which, prior to 1989, included 22 enterprises in the national energy sector. The company was incorporated in 1991 and currently operates the majority of the hydropower capacity in the country, with other power producers split off from this structure and operating as independent private or state-owned entities. The NEK EAD operates 28 hydropower plants as well as three pumped-storage plants with total installed capacities of 2,737 MW in turbine mode and 931 MW in pumping mode. These plants represent the main regulating capacities in Bulgaria, balancing the operation of nuclear and thermal power plants, the variable loads of solar and wind power plants, as well as industrial and households demand and ensuring control of frequency, capacities exchange and voltage control. Further activities of NEK EAD include electricity trade and the supply of electricity as the public electricity supplier and supplier of last resort.[9]

The national Energy and Water Regulatory Commission (EWRC), established in 1999 and reorganized in 2005 and 2015, is an independent national regulatory body in the fields of electricity, heat energy, natural gas and water. The EWRC is responsible for licensing in the energy sector, setting and regulation of tariffs, monitoring of the quality of services provided by licence holders and dispute resolution. The EWRC is also invested with the power to impose penalties for regulatory breaches.[10]

The annual regulatory period for electricity tariffs starts on 1 July every year. Electricity tariffs for household consumers issued by the EWRC on 1 July 2021 are displayed in Table 1. These tariffs include access and transmission tariffs for customers and exclude the value-added tax (VAT).[11]

Table 1. **Electricity Tariffs for Household Consumers in Bulgaria as of 1 July 2021**

Measuring method	*Time zones*	*Price (BGN/kWh (USD/kWh))*	*Total price including grid services (BGN/kWh (USD/kWh))*
With two scales	Day	0.148 BGN/kWh (0.089 USD/kWh)	0.204 BGN/kWh (0.120 USD/kWh)
	Night	0.058 BGN/kWh (0.035 USD/kWh)	0.115 BGN/kWh (0.069 USD/kWh)
With one scale		0.148 BGN/kWh (0.089 USD/kWh)	0.204 BGN/kWh (0.120 USD/kWh)

Source: Energo-Pro Sales AD[11]

Electricity tariffs for non-household consumers for the period of July–December 2020 are displayed in Table 2.[12] Overall, a slight but constant increase in electricity prices for both household and non-household consumers can be observed in recent years. As in other countries, the impacts of the COVID-19 pandemic have further accelerated this trend.

Table 2. **Electricity Prices for Non-Household Customers in July–December 2020**

Consumption bands	*Annual electricity consumption (MWh)*		*Prices (EUR/kWh (USD/kWh))*				
					Taxes, fees, levies and charges		
	Lowest	*Highest*	*Energy and supply*	*Network costs*	*Total*	*VAT*	*Environmental, including excise duty*
Band 1		< 20	0.0730 (0.086)	0.0284 (0.0330)	0.0215 (0.0250)	0.0205 (0.0240)	0.001 (0.001)
Band 2	20	< 500	0.0675 (0.080)	0.0259 (0.0310)	0.0199 (0.0230)	0.0189 (0.0220)	0.001 (0.001)
Band 3	500	< 2,000	0.0631 (0.074)	0.0188 (0.0220)	0.0176 (0.0210)	0.0166 (0.0200)	0.001 (0.001)
Band 4	2,000	< 20,000	0.0620 (0.073)	0.0155 (0.0180)	0.0167 (0.0200)	0.0157 (0.0180)	0.001 (0.001)
Band 5	20,000	< 70,000	0.0578 (0.068)	0.0140 (0.0170)	0.0156 (0.0180)	0.0146 (0.0170)	0.001 (0.001)
Band 6	70,000	≤ 150,000	0.0578 (0.068)	0.0058 (0.0068)	0.0140 (0.0170)	0.0129 (0.0150)	0.001 (0.001)
Band 7		> 150,000	0.0544 (0.064)	0.0054 (0.0064)	0.0132 (0.0160)	0.0122 (0.0140)	0.001 (0.001)

Source: NSI[12]

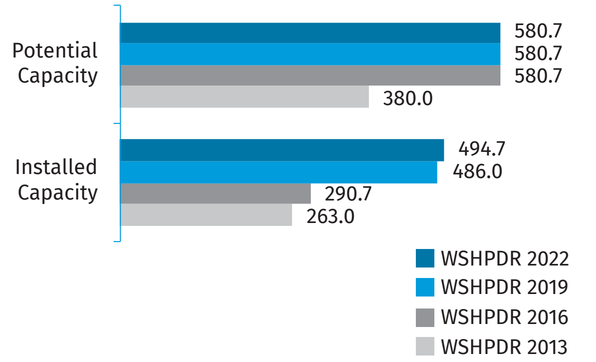
It should be noted that the national electricity market of Bulgaria has been undergoing intensive liberalization, particularly over the last decade. This is a continuous process requiring a significant time commitment and consisting of qualitative changes of the structure and functioning mechanisms of the market. One of the most important aspects of this process was the establishment of a balancing electricity market and its ongoing development. As of 1 October 2020, all non-household consumers connected at low voltage were obliged to purchase their electricity only on the free market.[13] The liberalization process of the electricity market of Bulgaria is governed by numerous national regulations under constant and intensive development, with a legal framework in place to meet the relevant European Union (EU) requirements.[14,15,16] As an example, the latest edition of the Energy Act includes 14 directives of the European Parliament and the Council of the EU and 15 relevant regulations are explicitly mentioned.[14]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no special legislative definition for small hydropower (SHP) in Bulgaria. However, various regulations contain special provisions for SHP plants. These include regulations specifying a 20 kW installed capacity limit for hydropower plants allowed to operate without a water use permit (which must also operate without diversion of the water stream) and regulations setting preferential electricity tariffs for hydropower plants with installed capacities in the 500 kW–10 MW range.[17,18] For the purposes of data comparison, this chapter considers SHP as plants with an installed capacity of up to 10 MW.

As of 2021, there were 245 SHP plants operating in Bulgaria, with a total installed capacity of 494.7 MW.[19,20] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity increased by approximately 2 per cent, due to more accurate data becoming available. Potential SHP capacity has remained constant, as no new studies of potential capacity have been conducted (Figure 3).[21]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Bulgaria (MW)**



Source: ANCHOR,[19] Kisliakov,[20] *WSHPDR 2019*,[21] *WSHPDR 2013*,[22] *WSHPDR 2016*[23]

Note: Data for SHP up to 10 MW.

Between 2016 and 2021, eight SHP projects were completed in Bulgaria, with the majority of these being reconstruction and rehabilitation projects on existing SHP plants, although no official data has been published on these projects.[19,20] A selection of SHP plants commissioned earlier in the decade is displayed in Table 3.

Table 3. **List of Selected Existing Small Hydropower Plants in Bulgaria**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Type of plant*	*Operator*	*Launch year*
Sabrano	Sabrano	2.17	76.4	Run-of-river	Stroyexpert Engineering –El OOD	2015
Kozloduy	Hurlets (on the outflow canal of the NPP)	5.50	7.2	Run-of-river	VEC Kozloduy EAD	2014
Narechen	Narechen	0.78	20.2	Diversion	Top Agro OOD	2014
Gurkovo	Gurkovo	0.37	36.0	Diversion	Maverik i Ko OOD	2013

Name	Location	Capacity (MW)	Head (m)	Type of plant	Operator	Launch year
Bebresh	Vrachesh	1.04	124.4	Diversion	Agro Engineering EOOD	2012
ERT-1	Gorni Lom	0.22	84.0	Diversion	ERT Hidro EOOD	2012
ERT-3	Gorni Lom	0.15	49.5	Diversion	ERT Hidro EOOD	2012
Sturna	Apriltsi	0.58	114.0	Diversion	Rosina Tsankovi OOD	2012
Cherni Vit	Cherni Vit	0.36	20.4	Diversion	Pro Arm EOOD	2012
Rosa	Mala curkva	1.23	92.3	Diversion	Hidro Eko Vat OOD	2012
Botunya	Stoyanovo	0.50	14.5	Diversion	Hydroenergy Construction EOOD	2011
Brusen	Brusen	0.28	3.6	Diversion	Baldor EOOD	2011
Dushevo	Dushevo	0.28	6.0	Run-of-river	Mira-El OOD	2011
Lakatnik	Lakatnik	2.90	8.8	Run-of-river	VEC Svoge AD	2011
Malusha	Gabrovo	0.40	240.0	Diversion	MVEC Malusha EOOD	2011
Opletnya	Opletnya	2.60	8.0	Run-of-river	VEC Svoge AD	2011
Tserovo	Tserovo	2.50	8.3	Run-of-river	VEC Svoge AD	2011
Lisets	Glozhene	0.23	7.6	Diversion	Energy Plus EOOD	2011
Zarenitsa	Chepelare	0.80	12.3	Diversion	SD Dyulger	2010
Cherepish	Zverino	3.48	7.1	Run-of-river	Ka-5 AD	2010

Source: ANCHOR,[19] Kisliakov[20]

SHP construction in Bulgaria is intensely controversial and currently hindered by a variety of social, political and legislative factors, due to aspects of the recent history of SHP development in the country. Prior to the first edition of the national River Basin Management Plans (RBMP) in 2009, a very large number of water rights permits for hydropower use (primarily for SHP projects) were issued in the country. However, these permits were issued piecemeal, without providing for integrated and environmentally aware development of the affected water bodies and without accounting for the public interest. This in turn generated a significant degree of pushback from non-governmental organizations (NGOs) in the form of social and legal campaigns challenging the ongoing SHP development, which resulted in numerous legal restrictions and prohibitions on SHP enacted by the authorities. At the current stage, these legal changes create a nearly insurmountable obstacle for the implementation of new SHP projects and, while negotiations and revisions to resolve this deadlock are ongoing, these are expected to take significant additional time. Several ongoing SHP projects of indeterminate status as well as several potential SHP sites are listed in Tables 4 and 5, respectively.

Table 4. **List of Selected Ongoing Small Hydropower Projects in Bulgaria**

Name	Location	Capacity (MW)	Head (m)	Type of plant	Developer	Planned launch year
Boaza 2	Gradnitsa	0.02	2.4	Run-of-river	Ekoenergia OOD	2021
Parvomayci	Parvomayci	0.23	2.7	Run-of-river	VEC Parvomayci OOD	2021
Karash	Karash	0.62	5.2	Run-of-river	Bulklima EOOD	2021
Preboynitsa	Gubislav	0.80	140.0	Diversion	Evroenergy MB OOD	2025
Levishte	Gabrovnitsa	3.00	7.8	Run-of-river	VEC Svoge AD	2025

Source: ANCHOR,[19] Kisliakov[20]

Table 5. **List of Selected Potential Small Hydropower Sites in Bulgaria**

Location	Potential capacity (MW)	Head (m)	Type of site (new or refurbishment)
Parvomay	N/A	4.0	Refurbishment
Karadzhalovo	N/A	30.0	Refurbishment
Sevlievo	0.12	86.4	Refurbishment

Source: Kisliakov[20]

RENEWABLE ENERGY POLICY

The key national document outlining renewable energy policy in Bulgaria is the National Renewable Energy Action Plan (NREAP) for the period of 2010–2020, in its 2011 revision, adopted in line with the Directive 2009/28/EC of the European Parliament and the European Council, also known as the Renewable Energy Directive (RED).[24,25] Although somewhat outdated, the NREAP defines preferred renewable energy sources (RES) and outlines the basic vision for meeting renewable energy targets at the time of the Plan's drafting. This includes an overall share target of 16 per cent of gross final energy consumption and 21 per cent of generated electricity to be met by RES by 2020.[25] It should also be noted that in 2019, the annual CO_2-equivalent per capita emissions of Bulgaria, at 5.9 tons, still ranked below the EU average of 6.4 tons.[26]

Following the mandate of EU Regulation 2018/1999 on the Governance of the Energy Union and Climate Action, in 2020 Bulgaria adopted its National Energy and Climate Plan (NECP) for the period of 2021–2030, which heavily emphasized RES development. According to the NECP, Bulgaria plans to increase the share of RES in final energy consumption by a further 9 per cent by 2030, reaching a total of 25 per cent.[27,28]

While Bulgaria has been successful in meeting its targets that were outlined in the 2010 NREAP, subsequent policy changes in Bulgaria caused investors to withdraw and lingering policy uncertainties remain an important factor behind a lack of confidence in RES amongst investors and banks.[27] The changes that triggered this reversal included the abandonment of economically unsustainable subsidies for RES and long-term power purchase agreements (PPAs) as well as the correction of market deformations induced by excessive investor confidence.[22] Additional obstacles are posed by the complexity of administrative procedures, the expense and the length of time required to obtain the necessary licences and permits to construct and operate RES facilities, caused in part by a lack of coordination by government agencies and national and local authorities on the issue of RES licensing.[26]

Policy on incentives for RES in Bulgaria is informed by the Guidelines on State Aid for Environmental Protection and Energy for 2014–2020, released by the European Commission in 2014. The document required EU Member States to implement a pilot bidding process for part of their RES projects in 2015–2016 and, starting with 2017, to implement competitive bidding as the only means of support for all new RES capacities, with feed-in premiums (FIP) and green certificates being the primary mechanisms for the bidding process and feed-in tariffs (FITs) retained only in the case of small-scale RES installations below 1 MW.[29]

In the case of Bulgaria, the FIT support scheme was terminated in 2009 for power plants using RES with a total installed capacity of over 4 MW, replaced by the FIP scheme.[24] Subsequently, in July 2021, the FIT scheme was also terminated for most RES plants with an installed capacity of up to 4 MW, with only plants with an installed capacity of up to 1 MW still supported by FIT and the rest required to sell their energy on the free market, bringing the FIT policy of Bulgaria in line with EU legislation. FITs in Bulgaria are issued for a guaranteed purchase period set by the PPA, which varies based on the type of RES: 20 years for solar power, geothermal power and biomass; 15 years for biogas and SHP; and 12 years for wind power.[30] The most significant additions of wind and solar power capacity in the country took place in 2011–2012, with some 1.5 GW added. This occurred when a FIT scheme with a high support level was in place at the same time as technology costs were falling, worldwide. Currently, the opposite trend is being observed, in large part due to the effects of the COVID-19 pandemic.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

With the national and EU level policy setting the boundary conditions for RES development in Bulgaria, SHP projects specifically are subject to the following additional regulations:

- The Water Act (most recently amended on 26 February 2021), which regulates the property and management of water resources on the territory of the Republic of Bulgaria and the related facilities. The Water Act includes several significant restrictions on hydropower development in the country, including a prohibition on the construction of SHP cascades, without including an explicit legislative definition of cascade, and a prohibition on hydropower construction on rivers in protected areas, streams with an average discharge of less than 100 l/s, or any hydropower construction that disturbs the hydraulic continuity of a watercourse;
- The Environmental Protection Act (last amended on 12 March 2021), which regulates the basic issues related to environmental protection in Bulgaria;
- Ordinance on the use of surface water, formulating the terms and conditions for the use of surface water bodies on the territory of Bulgaria;
- The Act on Protected Territories (last amended on 12 March 2021), which regulates the basic issues related to the rank, status, activities and protection of protected territories in Bulgaria;
- The Spatial Development Act (last amended on 12 March 2021), which regulates the basic issues of a building process and all related problems of the territory development and connection;
- The Law on Energy from Renewable Sources (last amendment of 12 March 2021), which regulates the specific issues related to the RES, their development and use.[18,31,32,33,34,35]

COST OF SMALL HYDROPOWER DEVELOPMENT

The cost of construction of SHP plants in Bulgaria per MW, including all preliminary studies, administrative and design activities, varies across a broad range—from approximately EUR 1 million to more than EUR 3.5 million. Factors affecting cost include both the implemented technical solutions and the time of construction. Consequently, the payback period for SHP projects can likewise vary anywhere from 3 to over 15 years. Overall, the cost has changed significantly in the last 20 years. A particular issue in Bulgaria is the incidence of rushed SHP projects caused by investor pressure. These have contributed to environmental problems and the negative reputation of SHP in the country.

EFFECTS OF CLIMATE CHANGE ON SMALL HYDROPOWER DEVELOPMENT

Climate change in Bulgaria is expected to significantly impact the amount and temporal distribution of precipitation in the coming decades. Annual precipitation is projected to decrease by approximately 15 per cent by 2050 and by 30–40 per cent by 2080, relative to the 1961–1990 baseline period. Seasonally, precipitation distribution is projected to become more uneven, with excess precipitation in the winter to be offset by drought during the summer months. These changes are expected to negatively impact the generation capacity and reliability of generation by hydropower in the country. Additionally, drought risk will increase competition for water use from various sectors, including thermal power plants that abstract and discharge water for cooling purposes.[36]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers to SHP development currently present in Bulgaria could be summarized as follows:

- Hydrological information is not publicly accessible, with the occasional exception of primary data that needs further qualified processing;
- Successive closure of nearly all local turbine and generator producing capacities in Bulgaria after 1989 (at the time, Bulgaria produced, under licence, large reversible pump-turbines with the highest head in the world), as well as the disbandment of all research and development units for hydraulic machinery;
- Significant legislative barriers to hydropower development included in the Water Act;
- Construction of hydropower plants is also prohibited at sites included in the River Basin Management Plans (RBMPs);
- More generally, SHP development in Bulgaria is not economically feasible without extensive support in the form of FIT and FIP mechanisms.

The key enablers for SHP development in Bulgaria include the following:

- Open electricity and financial markets;
- FITs for SHP are considerably higher than for large hydropower;
- Extensive financing options for SHP, including opportunities for credit from banks subject to negotiations on a case-by-case basis, direct private investments and different forms of public-private partnerships. In the frame of special temporarily available trust funds and programmes supported by the EU, financing of SHP projects also is possible under favourable conditions.

It should be noted, however, that the temporary political, economic and social uncertainty related to the COVID-19 pandemic has recently caused investors to refrain from complicated long-term projects with relatively low revenue rates. It should be additionally emphasized that an increasingly broad consensus is developing in Bulgaria on the need to ensure that investment projects, and SHP projects in particular, are sustainable, in the sense that the balance between social, environmental and economic needs is assigned the highest priority.

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Czech Republic

Pavel Štípský, chairman, and Helena Kamrlová, SPVEZ, z. s.

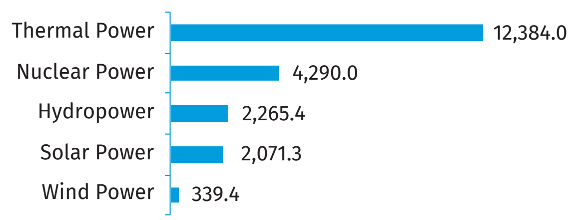
KEY FACTS

Population	10,698,896 (2020)[1]
Area	78,867 km^2[2]
Topography	There are two main regions in the Czech Republic: Bohemia in the west and Moravia in the east. Bohemia occupies the major portion of the territory and consists of the Bohemian Plateau surrounded by six mountain groups. Moravia occupies most of the eastern part of the country and is characterized by a hilly relief in the eastern part and a lowland character in the central part of the region. Mount Sněžka, at 1,603 metres, is the highest point of the country and lies in the east in the Krkonoše Mountains.[3]
Climate	The climate of the Czech Republic is mild but varies throughout the year and across regions, depending on the altitude. Temperatures are rather uniform in the low-lying areas of the country but decrease at higher elevations. January is the coldest month, with average temperatures in the lowlands reaching below 0 °C. Summer temperatures average at 20 °C but can exceed 30 °C in some parts of the country in July. Snow coverage usually lasts for several months at higher altitudes and only for several days in the lowlands.[4]
Climate Change	Climate change projections in the Czech Republic predict an increase in average seasonal temperatures of approximately 1.1–1.2 °C by 2030, while increases in average monthly temperatures are expected to reach approximately 3–4 °C in July and August by 2069, relative to the 1960–1990 reference period.[5]
Rain Pattern	Most precipitation falls in the months of June and July, while the months of January and February exhibit the least precipitation. In winter, precipitation occurs mainly in the mountains in the form of snow. Annual precipitation can vary significantly, from 410 mm to 1,700 mm. However, in most years precipitation is between 600 mm and 800 mm.[4]
Hydrology	The territory of the Czech Republic includes the main water divide of Europe, separating the North Sea, Baltic Sea and the Black Sea drainage basins. One of the major rivers of the country is the Elbe, with its tributaries the Vltava and Ohře, which drains most of the territory of Bohemia and flows into the North Sea. The Morava River, together with its tributaries, drains a major part of Moravia and flows into the Danube River. The Odra River, flowing into the Baltic Sea, drains a part of northern Moravia including the region of Slezia. The highest discharge is observed in the spring months as a result of snow melting in the mountains.[3,4,6]

ELECTRICITY SECTOR OVERVIEW

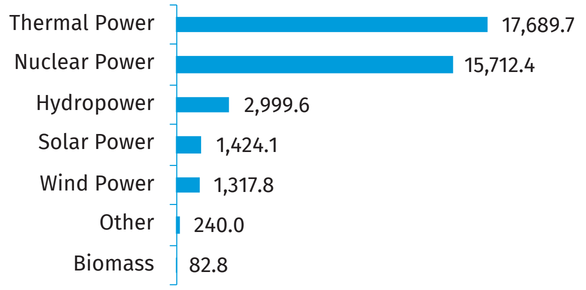
The total installed capacity of the Czech Republic amounted to 21,350.1 MW at the end of 2020, of which thermal power accounted for 12,384.0 MW (58 per cent), nuclear power for 4,290.0 MW (20 per cent), hydropower for 2,265.4 MW (11 per cent), solar power for 2,071.3 MW (10 per cent) and wind power for 339.4 MW (2 per cent) (Figure 1).[7] Electricity generation in 2020 reached 81,443.6 GWh, decreasing from 86,990.5 GWh in 2019. Conventional thermal power including gas-fired and coal-fired power plants provided 39,609.8 GWh (49 per cent) of the annual generation total, nuclear power provided 30,043.3 GWh (37 per cent), biomass and biogas provided 5,093.6 GWh (6 per cent), hydropower provided 3,437.0 GWh (4 per cent), solar power provided 2,235.1 GWh (3 per cent), wind power provided 699.1 GWh (1 per cent) and other sources provided 325.7 GWh (less than 1 per cent) (Figure 2).[7,8]

Figure 1. **Installed Electricity Capacity by Source in the Czech Republic in 2020 (MW)**



Source: ERO[7]

Figure 2. **Annual Electricity Generation by Source in the Czech Republic in 2020 (GWh)**



Source: ERO,[7] MIT[8]

Access to electricity in the Czech Republic is 100 per cent.[9] Total gross domestic consumption of electricity in 2020 amounted to 71,354 GWh, which included system losses of 4,117 GWh (approximately 5 per cent of gross annual generation). Imports in 2020 amounted to 13,368 GWh, while exports reached 23,520.9 GWh.[7]

The energy sector of the Czech Republic is regulated by the Energy Regulatory Office (ERO). Its responsibilities include price control, promotion of renewable and secondary energy sources, support for heat and power generation, granting of licensing permissions, protection of consumers and fair competition and supervision of the energy market. ERO additionally issues price decisions and compiles statistical data.[10]

The main participants of the electricity market of the Czech Republic include the Czech Transmission System Operator (ČEPS), distribution sector operators (DSOs), electricity generators, the market operator, electricity traders and consumers. ČEPS is a state-owned enterprise and is controlled by the Ministry of Industry and Trade (MIT), which holds an exclusive licence to maintain and operate the transmission system. The distribution network is privately operated, with major distributors including ČEZ Group, E.ON Energy and Prague Energy (PRE).

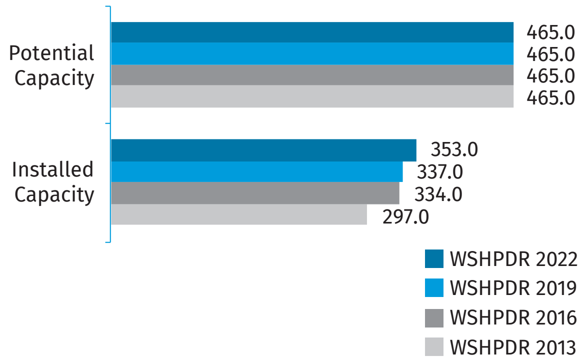
The price of the power component of electricity is determined on the market by individual suppliers, while the price for electricity transmission and other support services for final consumers as well as contributions to subsidies for renewable energy sources (RES) are regulated by ERO in its regular price decisions. The final tariffs for electricity depend on the category of consumer, level of consumption, chosen supplier and the length of the contract. The average price for household consumers ranged between 0.15 EUR/kWh and 0.25 EUR/kWh (0.17–0.28 USD/kWh) in 2019.[11] Substantial electricity price increases are expected for end users whose long-term fixed-price contracts are due to expire in 2022 due to the ongoing global energy crisis.[12]

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) plants are defined in the Czech Republic as hydropower plants with an installed capacity of up to 10 MW. SHP plants fall in the category of supported sources of electricity, which receive state subsidies to ensure their economic viability under the current market conditions.

As of 2020, there were 1,422 SHP plants in the Czech Republic with a total installed capacity of 353 MW and an annual production of 1,227 GWh.[12] Potential capacity for SHP in the country has been estimated at 465 MW in 2007, indicating that approximately 76 per cent has been developed so far.[13] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed SHP capacity has increased by approximately 5 per cent due to the commissioning of new plants. Potential capacity has remained static as no new comprehensive studies of SHP potential in the country have been carried out (Figure 3).[14]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in the Czech Republic (MW)**



Source: Štípský & Kamrlová,[12] Punys & Pelikan,[13] *WSH PDR 2019*,[14] *WSHPDR 2013*,[15] *WSHPDR 2016*[16]

The majority of operating SHP plants in the Czech Republic (953 plants) are micro-scale with a capacity of up to 100 kW and a total capacity of 38 MW. Micro-hydropower plants are typically located on historic sites such as old water mills, sawmills, glassworks and textile factories and are distributed fairly evenly across the territory of the country. Larger plants are located on major rivers, with SHP plants on the Elbe River accounting for a quarter of all installed SHP capacity.[12]

Owing to their territorial distribution, SHP plants play the role of decentralized sources of electricity generation. They do not burden the transmission system and thus have minimal transmission losses. Additionally, SHP plants improve the technical parameters at the endpoints of the low-voltage network, which helps to stabilize the network. In the Czech Republic, SHP plants are owned and operated by a variety of entities numbering approximately 1,100 independent operators, including individuals, various commercial and non-commercial entities and state water companies.

Approximately a third of SHP plants in the country are operated by the state through the majority state-owned ČEZ Group and the state-owned group of companies Povodí.[12]

Although previous studies have estimated total potential capacity of SHP in the Czech Republic in the hundreds of megawatts, technically and economically feasible potential in the country is almost entirely exhausted. According to a qualified estimate by the Czech Union of Entrepreneurs for the Use of Energy Resources (SPVEZ), the remaining realistically exploitable potential ranges from 35 MW to 50 MW, mainly composed of potential micro-hydropower sites with low individual capacities. More extensive development is not possible due to the long periods required to achieve financial returns on investment. Additionally, the remaining technically feasible SHP sites are situated mainly in mountainous areas, national parks and protected zones, where legislation either does not permit SHP development at all or renders it prohibitively complicated and costly. Additionally, the National Renewable Energy Action Plan (NREAP) adopted in 2012 set a total installed capacity target of 153 MW for SHP under 1 MW and 191 MW for SHP of 1–10 MW by 2020. This target had been exceeded as of 2018.[12,17]

The scale of recent SHP construction has consequently been quite small. In 2020, only 11 new SHP plants were commissioned in the country, with a total installed capacity of approximately 1 MW. A list of these plants is provided in Table 1. No information on ongoing or planned SHP projects in the country is available as private investors in the Czech Republic do not typically publicly advertise such plans.[12]

Table 1. **List of Small Hydropower Plants Commissioned in the Czech Republic in 2020**

Name	*Capacity (MW)*	*Launch year*
Ejpovice	0.314	2020
Papouščí skála	0.240	2020
Bohdíkov	0.150	2020
Perla Chocen II	0.132	2020
Trávníček	0.055	2020
Nišovice	0.037	2020
Rožmitál pod Třemšínem	0.030	2020
Nádražní	0.025	2020
Břevnice	0.019	2020
Bílkovice	0.019	2020
Střížeš nad Bečvou	0.018	2020
Total	**1.039**	

Source: Štípský & Kamrlová[12]

RENEWABLE ENERGY POLICY

In the Czech Republic, renewable energy projects are supported through either a guaranteed feed-in tariff (FIT) or a green bonus paid on top of the market price. The support schemes for electricity generation from renewable energy sources were first outlined in the 2012 Act on Supported Energy Sources (Act No. 165/2012). However, in 2013, the Act was amended by Act No. 310/2013, which abolished FIT support for all renewable energy projects put into operation after 31 December 2013, with the exception of SHP plants up to 10 MW. SHP plants commissioned on or prior to 31 December 2021 are eligible to choose between the FIT and the green bonus. Following additional amendments to the Act on Supported Energy sources adopted in October 2021, SHP plants commissioned on or after 1 January 2022 are not eligible for FIT support, and can receive support either in the form of green bonuses or auction bonuses.[18]

In October 2021, the years-long process of amending the Act on Supported Energy Sources and the Energy Act was completed. Among other functions, these two laws regulate the legislative framework for SHP for the next decade. Major changes included the introduction of an auction system of operating aid for newly commissioned RES plants, the setting of an internal rate of return (IRR), profitability checks of existing RES plants to avoid possible overcompensation and other measures. Future expected amendments include the shortening of the operating support period from 30 years to 20 years and stricter connection conditions. According to the amended Act on Supported Energy Sources, new SHP plants with a capacity of up to 1 MW are offered support in the form of a green bonus, while those with a capacity of 1-10 MW are offered support in the form of an auction bonus. However, in the context of the energy crisis and unpredictability in the entire energy sector across Europe during 2022, the Czech government has not, as of the first half of 2022, announced any RES auctions. There is also a continuing effort to enact an increase of the minimum permissible residual flows for watercourses, which would mean a further significant deterioration of the economic feasibility of SHP operation in the country.[12]

The FITs for still-eligible SHP plants are established by ERO on an annual basis. If a producer opts for the FIT, the contracted electricity distributor will be obliged to purchase all produced electricity. According to the 2005 Act on the Promotion of Electricity Production from Renewable Energy Sources, this scheme ensured investment payback within 15 years. The amended Act on Supported Energy Sources no longer provides for a guarantee of payback for newly commissioned plants, but only defines the conditions for determining the amount of operating aid that would ensure the sum of discounted cash flows over the lifetime of the plant is equal to zero. Green bonuses are calculated based on the time elapsed after the commissioning of the plant and represent a bonus to the market price of electricity, to which the producer is entitled for the electricity sold to a final customer or electricity trader. The plant operator receives this bonus from the state-owned Operator of the Electricity Market (OTE). In addition to these two schemes, RES projects can also receive investment subsidies.[16] Purchase prices and green bonuses for SHP plants established by Price Decision No. 6/2021 from 29 September 2021 are displayed in Table 2.

Table 2. **Purchase Prices and Green Bonuses for Small Hydropower in the Czech Republic in 2019–2021**

Type of SHP plant	*Year of commissioning*	*Purchase price (CZK/MWh (USD/MWh))*	*Green bonus (CZK/MWh (USD/MWh))*
SHP plants on established sites*	2019	2,349 (108.1)	1,154 (53.1)
	2020	2,303 (105.9)	1,108 (51.0)
	2021	2,258 (103.9)	1,063 (48.9)
Renovated SHP plants	2019	2,349 (108.1)	1,154 (53.1)
	2020	2,303 (105.9)	1,108 (51.0)
	2021	2,258 (103.9)	1,063 (48.9)
SHP plants in new locations	2019	2,909 (133.8)	1,714 (78.8)
	2020	2,852 (131.2)	1,657 (76.2)
	2021	2,796 (128.6)	1,601 (73.6)

Source: ERO[19]

Note: *referring to sites with an active power plant and grid connection as of 1995 or later.

From the first half of 2021, however, a significant rise in the prices of the power components of electricity has been observed across the European Union, which has had a major impact on the electricity sector in the Czech Republic and the SHP sector in particular. In response to an increase in market prices for electricity, purchase price subsidies for RES are decreasing. In particular, ERO has set the operating support for SHP plants in the form of green bonus at 0 CZK/kWh in its price decision for 2023, due to the significant increase in the market price of electricity and the consequent expectation that SHP plants will have become fully competitive by that date and no longer require support. As of June 2022, it was not possible to make a qualified prediction on future price dynamics, although in July, traders started publishing price lists for new contracts with substantial increases in the price of the power component of electricity.[12]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Key regulations for SHP plants are established by the Water Law of the Czech Republic. Permits for the construction of any hydraulic structure including SHP plants are issued by the relevant Water Legal Office and require the submission of the following documents:

- Documents in line with the Building and Spatial Planning Law regulations, including the opinion of the local administration department;
- Design documentation, including a water legal action plan and a description of the potential hydraulic and ecological impact, impact on protected areas and information on the main discharge indicators;
- Opinion of the relevant water basin administrator and the administrator of the specific watercourse;
- Water use concessions and/or building permits previously issued by other offices;
- Maps and any other relevant documents pertaining to the planned inundation area in case of plants with a reservoir.

SHP investors are expected to apply for a grid connection with the relevant distribution system operator simultaneously with applying for a construction permit. Along with other RES, SHP plants receive priority for grid connections over conventional plants. Finally, SHP plant operators must apply for an operating licence with the ERO.[20]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change modelling predicts an overall minor decrease in streamflow and a significant increase in streamflow uncertainty over the course of the 21st century. Relative to the 1981–2010 control period, a 12 per cent reduction in mean flow is predicted for the 2061–2080 time horizon and a 17 per cent reduction for the 2080–2100 time horizon. Uncertainty of streamflow predictions oscillated by a factor of four over 34 climate models for the time horizon of 2021–2040, indicating that outflow from rivers could be either half or twice of its volume during the control period, with uncertainty increasing substantial for further time horizons. While this uncertainty does not reflect likely streamflow scenarios, it significantly complicates long-term planning of the development of hydrological resources in the country.[21]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

While SHP has a significant presence in the Czech Republic, further development of SHP in the country is limited by several factors:

- High operation and maintenance costs;
- Complicated licensing process;
- Prioritization of fossil fuels and nuclear power over RES in the country's energy strategy;
- Gradual reduction in financial support for RES development as a whole;
- Existing regulations limiting SHP development at many potential sites;
- Political and social pushback to SHP development, with possible future restrictions on streamflow reduction to further undermine economic prospects for SHP;
- Largely exhausted undeveloped SHP potential and a lack of remaining prospective sites for development;
- Expected adverse impacts of climate change on river flow.

Enabling factors for SHP development in the Czech Republic include:

- Historical experience and domestic technical capacity for the operation and development of SHP plants and equipment;
- Several existing support schemes including FITs, green bonuses and investment subsidies;
- Some remaining undeveloped potential capacity;
- Potential for the refurbishment of existing SHP plants, specifically provided for in the RES support structure.

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Hungary

Béla Munkácsy and José Campos, Eötvös Loránd University

KEY FACTS

Population	9,772,756 (2019)[1]
Area	93,030 km^2 [2]
Topography	Flat terrain prevails as the county is dominated by the Great Hungarian Plain east of the Danube. Most of the country lies at an elevation of less than 200 metres above sea level. The highest point is Mount Kekes (1,014 metres) in the Matra Mountains, north-east of Budapest. The lowest point lies at 75.8 metres above sea level, at the Tisza River, near Szeged.[2]
Climate	Hungary is characterized by a temperate climate, with cold, cloudy and humid winters and warm summers. The average annual temperature ranges between 10 °C and 11 °C. July and August are the warmest months with an average temperature of 21 °C, whereas December and January are the coldest months with an average temperature of 0 °C.[3]
Climate Change	Climate change is expected to cause significant warming in Hungary with seasonal warming of 1-3 °C for the 2021-2050 period. While total annual precipitation is projected not to change significantly, seasonal variations are expected. Summer precipitation is likely to decrease, while autumn and winter precipitation is likely to increase during the 21st century.[4]
Rain Pattern	Total mean annual precipitation is approximately 600 mm. June is the wettest month, with an average precipitation of 70 mm, and February is the driest, with 30 mm of rainfall.[5]
Hydrology	Hungary has moderate water resources, which is explained by the plain-dominated topography. The two most important rivers are the Danube (length: 417 km; average flow: approximately 2,000 m^3/s; fall in the Hungarian section: 30 m; average: 7 cm/km) and the Tisza (length: 590 km; average flow: 800 m^3/s; the fall in the Hungarian section: 38 m; average: 6.4 cm/km). The navigability is limited mainly in the case of the Tisza River. Lake Balaton (594 km2) is the largest lake in Central Europe and Lake Héviz (47.5 km^2) is the largest thermal lake in Europe.[6]

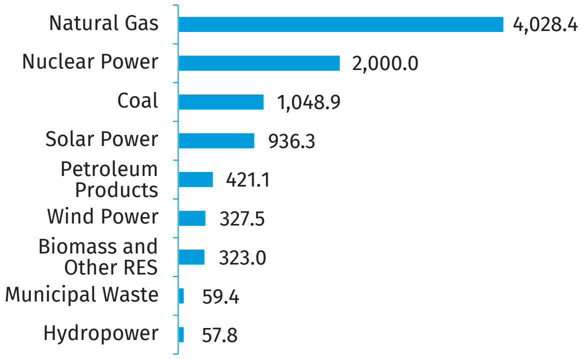
ELECTRICITY SECTOR OVERVIEW

The electricity generation mix is composed of nuclear power, coal (lignite), natural gas, petroleum products, renewable sources (solid biomass, biogas, wind, solar, hydropower, geothermal, municipal waste). Gross electricity generation amounted to 34,154 GWh in 2019, with nuclear power accounting for almost 48 per cent, natural gas 25 per cent, coal 12 per cent, biomass 5 per cent, solar power 4 per cent, wind power 2 per cent, biogas 1 per cent, hydropower 1 per cent, municipal waste 0.4 per cent, petroleum products 0.2 per cent, geothermal power below 0.1 per cent and other sources (blast furnace, coke oven gas, tail gas, non-renewables waste) 1 per cent (Figure 1).[7]

All rural and urban areas of the country (100 per cent of the total population) have access to the electricity supply.[9] It should be mentioned that approximately 28 per cent of consumed electricity was imported in 2018.[10] Moreover, the country faces a need for efficiency measures as well as for new generating capacities, which are mainly to replace old power plants.[11] There is one state-owned nuclear power plant located near the town of Paks, Paksi Atomerőmű. This power plant accounted for almost 50 per cent of the domestically generated electricity in 2019. The Paks power plant is composed of four reactors with a total gross capacity of 2,000 MW.[8] These units have been approved for a lifetime extension of 20 years until 2032, 2034, 2036 and 2037, respectively.[12] In 2017, the European Commission approved funding for the construction of the Paks2 nuclear power plant. Two new reactors, each with an installed capacity of 1,200 MW, will replace the four currently operating units of 500 MW that were installed in the 1980s.[13] The new reactors are expected to be commissioned in 2026–2027. The Government considers the Paks2 project strategic for replacing the old plants and reducing the country's import dependence. However, without uranium mines in Hungary, all the nuclear fuel will have to be imported.

In 2019, electricity generation from gas and coal accounted for approximately 25 per cent and 12 per cent of total generation, respectively. The Mátrai Erőmű, a lignite-based power plant with an installed capacity of 940 MW, is the second-largest power plant in the country.[8] The Paks nuclear power plant and the Mátrai power plant combined accounted for nearly 60 per cent of the electricity generated in the country in 2019. At the same time, renewable energy sources combined contributed approximately 14 per cent of total generation. Among renewable energy sources, only the solar photovoltaic (PV) installed capacity has grown significantly in recent years with a fourfold increase in electricity production between 2017 and 2019.[8]

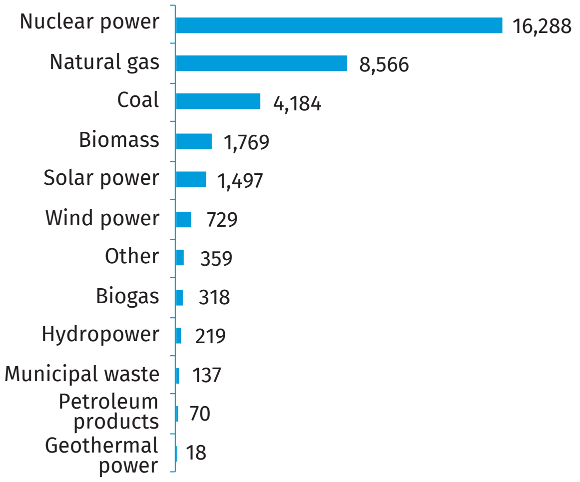
Figure 1. **Installed Electricity Capacity by Source in Hungary in 2019 (MW)**



Source: HEA[8]

The installed power production capacity at the end of 2019 was 9,202 MW, with 44 per cent coming from natural gas-fired power plants, 22 per cent from nuclear power, 11 per cent from coal-fired plants, 10 per cent from solar power, almost 5 per cent from oil-fired plants, 4 per cent from wind power, 4 per cent from biomass and other renewable energy (including biogas and geothermal power), 0.6 per cent from municipal waste and 0.6 per cent from hydropower (Figure 2).[8] Thus, in 2019 renewable energy sources combined accounted for roughly 19 per cent of the total installed capacity.

Figure 2. **Annual Electricity Generation by Source in Hungary in 2019 (GWh)**



Source: HEA[8]

The installed capacity of solar PV systems is expected to reach 3,000 MW by 2023 and 6,500 MW by 2030 according to the National Energy and Climate Plan.[11] The wind power capacity has not increased since 2010. Since 2016 all wind power developments have been banned by law in Hungary. The reason for the ban is currently unclear. Typical arguments include the lack of wind resources and the undesirable appearance of turbines in the landscape. However, the fact that wind turbines currently operate in the country is an example that contradicts this argument. What could be in the background of the decision is that cheap wind energy would be a competitor for the Paks2 nuclear project.[14]

Based on the European Union (EU) regulations on the single energy market, Hungary effectuated ownership unbundling as well as the creation of a national regulatory sector and an Agency for the Cooperation of Energy Regulators. This means that in Hungary power plants can be privately owned and producers can sell their electricity directly to customers or on the wholesale market, although the prices for universal suppliers are still regulated.[15] The Hungarian Energy and Public Utility Regulatory Authority (HEA) is the market regulatory body, whose main tasks include licence issue and ratification of the grid fees for transmission and distribution system operators.[16]

The state-owned MAVIR is the only transmission system operator (TSO) in Hungary. There are six distribution system operators (DSOs): E.ON South-Donau DSO, ÉMÁSZ DSO, E.ON North-Donau DSO, NKM Electricity Supplier DSO (state-owned), ELMÜ DSO, and E.ON Tisza-region DSO. In 2019, the total length of the Hungarian transmission network was 4,870 km and the total length of the distribution network was 163,854 km. In the same year, the maximum winter 15-minute peak load was 7,105 MW, while the maximum summer peak load was 6,633 MW.[8]

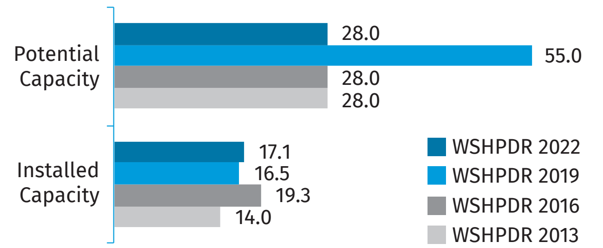
HUPX is the operator of the Hungarian day-ahead and intraday power exchange market.[17] Hungary is part of the bidding zone for the wholesale market including the Czech Republic, Slovakia and Romania. End-user prices are regulated; therefore, network costs remain the only component of the final electricity price that varies, though only slightly, across the country depending on the DSO responsible for the region. The HEA determines the network tariffs for transmission and distribution and sets universal service prices on an annual basis.

Electricity prices are set for households and small enterprises and, therefore, do not vary significantly across the country. Gradual price cuts have been realized by the Government in recent years aiming to ensure affordable electricity for all residential customers. According to the comparison of residential customer prices in the EU as of October 2020, the average price that a typical Hungarian household customer paid was 0.1063 EUR/kWh (USD 0.13/kWh), which was one of the lowest in the EU.[18] However, considering the average salaries as well, it can be stated that the sum that Hungarian households pay for electricity accounts for a relatively high share of income compared to other EU countries.[19] On the other hand, household customers do not bear the costs of supporting mechanisms for renewable electricity.

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) is defined by Hungarian regulation as hydropower plants with an installed capacity of 5 MW or less.[20] A total of 28 SHP plants with a generation capacity of up to 5 MW were operating in the country at the end of 2019, adding up to an overall installed capacity of 17.1 MW (Figure 3).[21] The average installed capacity of these SHP plants was 0.6 MW. Combined, the SHP plants produced approximately 68 GWh of electricity in 2019. The economic potential capacity for SHP in the country is currently estimated at 28 MW.[20] The total technical potential capacity for SHP plants was previously estimated at 55 MW with an annual generation of 300 GWh.[22] Compared to the results of the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP in Hungary increased slightly, by 0.6 MW. One reason is the refurbishment of the Gibárt SHP plant (total capacity 0.49 MW), which increased the capacity of the plant by approximately 70 per cent.[23] A new SHP plant with an installed capacity of 0.31 MW was also built in Szentgotthárd. Conversely, the SHP potential has decreased due to the use of the economic potential estimate in the current edition compared to the technical potential estimate used in the previous one.

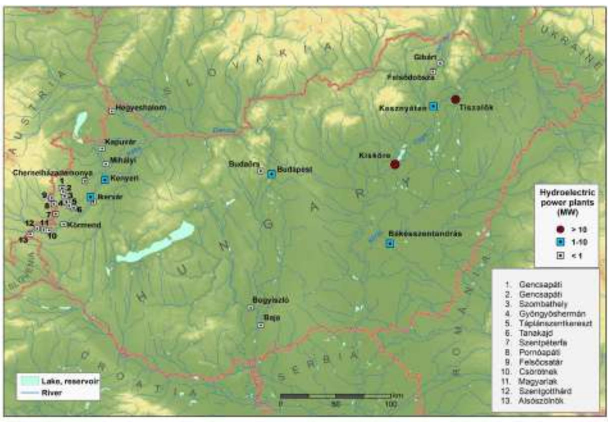
Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Hungary (MW)**



Source: MND,[20] Munkácsy & Campos,[21] *WSHPDR 2019*,[22] *WSHPDR 2013*,[24] *WSHPDR 2016*[25]

Note: The SHP potential estimate in the *WSHPDR 2019* referred to the technical potential.

Figure 4. **Hydropower Plants Operating in Hungary in 2019**



Source: Munkácsy & Campos[21]

Note: Map edited by Csüllög, G.

There are also two hydropower plants with an installed capacity above 10 MW in Hungary; one is located in Kisköre (28 MW) and one in Tiszalök (12.9 MW) (Figure 4). Table 1 presents the main attributes of some operational SHP plants. All 28 SHP plants are connected to the electricity grid.

Due to the relatively unfavourable natural conditions, such as the mountainous terrain and spatial and temporal differences in the distribution of rainfall in the country, the total hydropower potential in Hungary can be considered modest. Nevertheless, development opportunities do exist, particularly for plants of up to 5 MW.[20] However, no detailed feasibility studies are available to identify SHP projects most suitable for investment.

The Hungarian hydropower tradition dates back to 1896 when the first plant was built on the Rába River near Ikervár. Some SHP plants are more than 100 years old, such as the two on the Hernád River (located near Gibárt and Felsődobsza). Refurbishments have been performed over the years and these plants are still operating. These hydropower plants are important landmarks and constitute part of the culture of small villages. SHP plants are also considered environmentally friendly and have some level of acceptance by the public. New projects are rare, which can be explained by the fact that most feasible sites have already been developed.

Table 1. **List of Selected Operational Small Hydropower Plants in Hungary**

Name	*Location*	*Capacity (MW)*	*Head*	*Plant type*	*Turbine type*	*Operator*	*Launch year*
Alsószölnöki vízerőmű	Alsószölnök (Rába)	0.250	3.00	Run-of-river	Francis		1960
Békésszentandrási vízerőmű	Békésszentandrás (Körös)	2.034	4.85	Run-of-river	Kaplan	Hydro Power Consulting Magyarország Tanácsadó Kft.	2013
Csörötneki vízerőmű	Csörötnek (Rába)	0.485	3.50	Run-of-river	Francis	Szombathelyi Vízerőmű Kft	1919
Damonyai vízerőmű	Damonya (Pinka)	0.025	1.80	Run-of-river	Francis		1951
Felsőcsatári vízerőmű	Felsőcsatár (Pinka)	0.090	3.50	Run-of-river	Francis		1950
Felsődobszai vízerőmű	Felsődobsza (Hernád)	0.948	3.00	Run-of-river	Kaplan	ALTEO Group	1911

Name	Location	Capacity (MW)	Head	Plant type	Turbine type	Operator	Launch year
Gibárti vízerőmű	Gibárt (Hernád)	0.490	4.40	Run-of-river	Francis	Észak-magyarországi Áramszolgáltató Nyrt.	1903
Kapuvári vízerőmű	Kapuvár (Rába)	0.175	2.70	Run-of-river	Francis		1968
Kenyeri vízerőmű	Kenyeri (Rába)	1.542	4.40	Run-of-river	Kaplan	Kenyeri Vízerőmű Kft.	2008
Körmendi vízerőmű	Körmend (Rába)	0.400	4.10	Run-of-river	Francis	Szombathelyi Vízerőmű Kft	1930
Lukácsházai vízerőmű	Lukácsháza (Gyöngyös)	0.022	3.20	Run-of-river	Francis		1952
Pornóapáti vízerőmű	Pornóapáti (Pinka)	0.260	4.20	Run-of-river	Francis		1951
Szentgotthárdi vízerőmű	Szentgotthárd (Rába)	0.310	4.00	Run-of-river	Archimedean screw	Charpatia Vízerőmű Kft.	2017
Szentpéterfai vízerőmű	Szentpéterfa (Pinka)	0.110	3.7	Run-of-river	Francis		1951

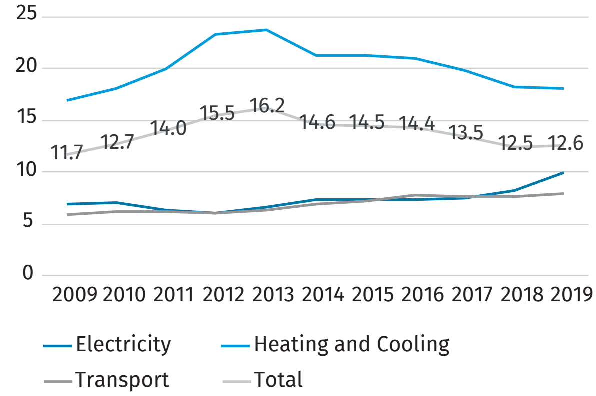
Source: Munkácsy & Campos,[21] OIM[26]

RENEWABLE ENERGY POLICY

The Ministry of Innovation and Technology is responsible for renewable energy policy, climate policy and energy efficiency programmes. The binding target set for Hungary by the Renewable Energy Directive 2009/28/EC (European Parliament and Council) was a 13 per cent share of renewable energy in final energy consumption by 2020. The National Renewable Energy Action Plan established 14.65 per cent as the target. The 13 per cent target was almost achieved in 2019 (Figure 5) with firewood having a significant share of the renewable energy sources in final energy consumption. However, it is estimated that a large amount of firewood is illegally cut which jeopardizes the sustainable use of this source.[27]

From 2020 onwards, the latest National Energy Strategy 2030 and the National Energy and Climate Plan constitute the basis of the Hungarian renewable energy policy.[9,28] The new renewable energy target for 2030 is a mere 21 per cent (in gross final energy consumption), which is far from the EU average of 32 per cent. The concept is based only on the large solar PV capacity extension. The hydropower installed capacity is not expected to change until 2040.

Figure 5. **Sectoral and Overall Shares of Renewable Energy Sources in Gross Final Energy Consumption, 2009–2019 (%)**



Source: HEA[7]

As mentioned, SHP plants are more accepted among the public and decision-makers, but the situation is different for large hydropower developments. One of the reasons is the controversial Gabčíkovo–Nagymaros Dams project between Hungary and Slovakia on the Danube River. The project was suspended due to environmental concerns and was only partly finished.[29] Pumped-storage hydropower is a recurring topic of discussion, but there are currently no official plans.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The licensing process for a new SHP plant development is composed of three main permission procedures. The first one is a construction permission, which is obtained from the local government. The second one is an environmental permission obtained from the regional environmental authority. Environmental impact assessment is needed if the SHP plant is planned in a protected natural area. Permission from the water resource authority is part of the construction and environmental permission procedures. The third permission is for grid connection and is obtained after an agreement with the DSO. Technical requirements may vary according to individual DSOs. The whole authorization process takes at least 12 months.

COST OF SMALL HYDROPOWER DEVELOPMENT

SHP development costs have a highly site-specific nature. Electromechanical equipment, design and connection to the grid are some factors influencing projects costs.[30] The total cost per unit of installed capacity for the majority of hydropower projects globally ranged from 600 USD/kW to 4,500 USD/kW in the period 2010-2019.[31] However, it is possible to find projects costs outside this range and some projects in Hungary are examples of these. Some costs of SHP refurbishment and new construction projects in Hungary are presented in Table 2. Among these developments, the most recent one is the Gibárt SHP plant with an expected production of 5.75 GWh/year.[31]

Table 2. **Cost of Refurbishment and Construction of Small Hydropower Projects in Hungary**

Location	*Installed capacity (MW)*	*Type of site*	*Year of completion*	*Cost*
Felsődobsza	0.948	refurbishment	2012-2013	0.95 million HUF/kW (4,318 USD/kW)
Gibárt	0.490	refurbishment	2020	2.45 million HUF/kW (8,221 USD/kW)
Nick/Kenyer	1.542	new	2008	1.30 million HUF/kW (6,311 USD/kW)
Szentgotthárd	0.310	new	2017	1.23 million HUF/kW (4,677 USD /kW)

Source: ALTEO,[32] NFM,[33] ALON[34]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The METÁR system is a feed-in tariff (FIT) and feed-in premium system. It is a mechanism to support the integration of renewable electricity producers into the market, as well as to support the fulfilment of the country's renewable energy targets. The METÁR system is built on three pillars based on the installed capacity of the plant: 1) a FIT (50 kW–500 kW); 2) the so-called 'green premium' granted without tendering (0.5 MW–1 MW) and 3) a 'green premium' granted through tendering procedures (> 1 MW). As of early 2021, there had been one auction completed under the METÁR system and a second one was ongoing. With one exception, only solar PV projects were supported, namely 71 projects. The exception was one landfill gas application.[35]

As of 2020, FIT rates were 32.05 HUF/kWh (0.11 USD/kWh) for hydropower plants below 0.5 MW. SHP plants between 0.5 MW and 1 MW can apply for a premium above the reference market price without taking part in the tendering procedure. The premium tariff rates were 26.70–33.26 HUF/kWh (0.091–0.11 USD/kWh) for hydropower plants up to 1 MW in 2020.[36] New investments and existing hydropower plants that undergo significant refurbishment or developments costing more than 50 per cent of the original initial investment cost may also apply for the METÁR support system. SHP plants under 50 kW can be supported under a net-metering regime. The MÉTAR mechanism is financed by industrial electricity consumers proportionally to the amount of electricity purchased.[37]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The prognosis for precipitation shows that the annual sum of precipitation may not change significantly in Hungary. However, summer precipitation is likely to decrease, while autumn and winter precipitation is likely to increase.[3] Changes in the runoff of rivers are expected to influence hydropower generation. While the potential generation may slightly increase at the global level by 2050, projections for Central Europe point to the opposite direction. A reduction in the order of 0.1 to 2.5 per cent of the technical potential is estimated by 2050.[38] It can therefore be concluded that the climate crisis will pose risk to SHP development in Hungary.

In a scenario of average temperature increases in the summer, electricity consumption could be affected, particularly considering the recent increase in air conditioning unit ownership. Heating electricity requirements in the country are likely to decrease due to an average increase in winter temperatures.[39] However, more factors need to be considered, such as the share of electricity in the heating energy mix and efficiency measures.

Thus, changes in the climate could also contribute to SHP development, however, there are no indications that new SHP will be preferred over other generation capacity choices.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are currently 28 operational SHP plants in the country adding up to 17.1 MW of installed generation capacity. Some refurbishment works have been completed, which have slightly increased the total installed capacity by 0.6 MW since the *WSHPDR 2019*.

Moderate water resources because of the plain-dominated topography and seasonal variations in the distribution of rainfall are limiting factors for hydropower development in Hungary. Two main barriers are identified for the SHP sector in particular:

- The National Energy and Climate Plan focus on expanding the capacity of the nuclear power plant. Moreover, the Plan focuses on solar PV technology among the renewable energy sources and does not propose new hydropower;
- The most suitable sites for SHP have already been developed.

The following factors are enablers for SHP development:

- The total economic potential of 28 MW has not yet been fully developed;
- The remaining technical potential is estimated at 38 MW.

Although the METÁR FIT system could be an enabler, it is currently unclear whether the system is effective in promoting SHP development because by 2021 only one auction had been completed and there have been no other hydropower projects proposed.

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Moldova

Nicolae Soloviov, Energy Efficiency Agency Moldova

KEY FACTS

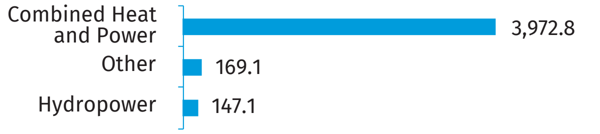
Population	2,643,883 (2020)[1]
Area	33,851 km^2 [2]
Topography	The relief of Moldova includes hills and flatland areas, with uplands mostly located in the central part of the country. The average altitude is 147 metres above sea level. The highest altitude is 429.5 metres at the Bălănești Hill and the minimum is at about 2 metres above sea level in the lower course of the Nistru River. The country's hills are part of the Moldavian Plateau, with altitudes varying between 240 and 320 metres. In the western area near Prut, there is a series of reefs, the so-called "taltra". In the south, the country has a small flatland, the Bugeac Plain.[3]
Climate	The Republic of Moldova is located in the temperate-continental zone, characterized by mild winters and long hot summers with low humidity. The continental climate is influenced by the Black Sea. Summers are hot with an average daytime temperature of over 24 °C in July, although highs can sometimes reach over 40 °C. Winters are mild with average daytime temperatures between -5 °C and -3 °C in January. [4]
Climate Change	In recent decades, increases in annual air temperatures have exceeded historical norms. Between 1981 and 2008, annual temperatures rose by approximately 0.58 °C per decade, compared with an average increase of 0.035 °C per decade between 1887 and 1980.[5] Additional climate change impacts have included droughts and major floods. These, along with the effects of rising average temperatures and the unequal distribution of rainfall throughout the year, have had negative consequences for the country's economy and the welfare and health of the population.[3] Climate change models predict a continuing rise of annual air temperatures in the country, with an increase of 1.7–2 °C by 2039 and of as much as 4.1–5.4 °C by 2099, relative to the baseline period of 1961–1990. Significantly, mean winter temperatures could increase from the baseline value of -2 °C to +2–4 °C by the 2080s.[5]
Rain Pattern	The territory of Moldova is characterized by insufficient humidity, with low and variable rainfall.[4] Annual precipitation is generally lower in the south-east of the country, at approximately 448 mm, and in the north-west it averages 596 mm. Precipitation falls mainly during the warm period of the year in the form of rain showers and only 10 per cent of annual precipitation falls in the form of snow.[6]
Hydrology	The hydrographic network of Moldova includes 3,621 rivers (of which 10 are over 100 km long), 57 lakes with a total area of 52.6 km^2 and approximately 3,000 reservoirs. The total length of the rivers in the country exceeds 16,000 km. The Dniester (Nistru) river is located on the borders of Ukraine and Moldova and has an annual discharge of approximately 10 km^3. Another river located on the border of Moldova and Romania is the Prut, with an annual discharge of 2.4 km^3. The main natural lakes are located on the Prut River watercourse. Small artificial lakes include the Costesti-Stinca reservoir on the Prut River (736 million m^3) and Dubasari Reservoir on the Nistru River (277 million m^3). The average density of the hydrographic network in the country is 0.48 km/km^2. The main water sources are the Dniester River (comprising 54 per cent of all water resources in the country), the Prut River (16 per cent), groundwater (23 per cent) and other surface water sources (7 per cent).[3]

ELECTRICITY SECTOR OVERVIEW

The electricity sector in Moldova is dominated by combined heat and power (CHP), including plants running on coal, natural gas and oil as well as certain biofuels. The total installed capacity in the country was 2,999 MW in 2020, with the CHP plants accounting for 2,850 MW or approximately 95 per cent of the total capacity. Many CHP units can operate based on different fuels: oil can be used in 2,778 MW of installed capacity, natural gas in 2,383 MW and coal in 1,600 MW. In addition to CHP, hydropower provided 62 MW and other sources including renewable energy sources (RES) provided 87 MW (Figure 1).[7,8]

Electricity deliveries to the distribution network in Moldova in 2020 equalled 4,289 GWh, of which 3,972.8 GWh (93 per cent) were provided by CHP, 147.1 GWh (3 per cent) by hydropower, and 169.1 GWh (4 per cent) by other sources, including 167.2 GWh imported from Ukraine (Figure 2).[7,8]

Figure 2. **Electricity Delivered to the Grid by Source in Moldova in 2020 (GWh)**

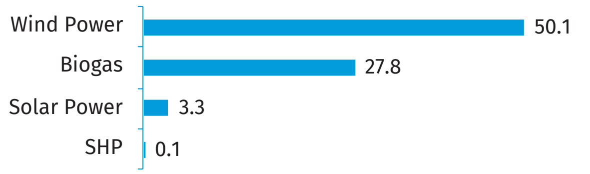


Source: Moldelectrica,[7] Moldelectrica[8]

Note: Electricity deliveries to the grid from RES other than hydropower not included due to conflicting data.

Electricity generation from RES in 2020 amounted to 81.3 GWh, with wind power accounting for 50.1 GWh (62 per cent) of the total, biogas producing 27.8 GWh (34 per cent), solar power contributing 3.3 GWh (4 per cent), and small hydropower (SHP) contributing approximately 0.1 GWh (less than 1 per cent) (Figure 3).[9]

Figure 3. **Annual Electricity Generation by Renewable Energy Sources in Moldova in 2020 (GWh)**



Source: ANRE[9]

Electricity consumption in Moldova has been steadily increasing in recent years, driven primarily by increasing household consumption of electricity. In 2020, country-wide electricity consumption reached 3,866.2 GWh, decreasing by approximately 0.2 per cent from 3,875.1 GWh in 2019. Consumption by households increased by 3.5 per cent, from 1,663.2 GWh in 2019 to 1,721.3 GWh in 2020. Consumption in rural areas grew by 4.1 per cent, from 804.0 GWh in 2019 to 837.3 GWh in 2020. Finally, consumption in urban areas grew by 2.9 per cent, from 859.2 GWh in 2019 to 883.9 GWh in 2020. At the same time, electricity consumption by non-household consumers decreased by 3.0 per cent, from 2,211.8 GWh in 2019 to 2,144.9 GWh in 2019.[9] Imports of electricity equalled 167.2 GWh in 2020.[7] As of 2019, the electrification rate in Moldova was 100 per cent.[10]

The infrastructure of the energy grid of Moldova was built during the Soviet period, as part of a common system optimized for operation between the Soviet Union and neighbouring countries: Bulgaria, Hungary and Romania. As Moldova suffers from insufficient domestic electricity generation capacity, it uses interconnections with Ukraine and Romania to cover its electricity needs and to balance the energy system. These interconnections include 7 lines of 330 kV and 11 lines of 110 kilovolts (kV) of interconnection with Ukraine as well as 1 line of 400 kV and 4 lines of 110 kV of interconnection with Romania.[11] According to Government Decision No. 102 of 5 February 2013 on the Energy Strategy of the Republic of Moldova until 2030, one of the objectives for the period 2013–2030 is to strengthen bidirectional transmission connections between the Integrated Power System/United Power System (IPS/UPS) and the European Network of Transmission System Operators of Electricity (ENTSO-E), allowing the Republic of Moldova to become an energy transit country.[11]

The National Agency for Energy Regulation (ANRE), established by Government Decision No. 767 of 11 August 1997, is the national energy regulatory authority of Moldova. ANRE is an independent entity directly subordinate to the Parliament. It implements state energy policy, sets energy tariffs including those for electricity and ensures the regulation and monitoring of the energy market.[12]

Tariffs for electricity for the years 2001–2019 are displayed in Table 1. While the prices have generally seen an upward trend when denominated in the national currency, the primary factor driving fluctuations in electricity prices in Moldova has been the evolution of the exchange rate of the national currency (MDL) to the US dollar used for the purchase of imported energy.

Table 1. **Electricity Tariffs in Moldova in 2001–2019**

Electricity price excluding VAT (MDL/kWh (USD/kWh))	*2001*	*2005*	*2010*	*2017*	*2018*	*2019*
Red Nord	0.63 (0.05)	0.70 (0.06)	1.43 (0.12)	1.93 (0.10)	1.79 (0.10)	2.02 (0.12)
Red Nord-West	0.68 (0.05)	0.70 (0.06)	1.43 (0.12)	2.04 (0.10)	1.79 (0.10)	2.02 (2.02)
Premier Energy (RED UF)	0.68 (0.05)	0.78 (0.06)	1.33 (0.11)	1.85 (0.09)	1.73 (0.10)	1.77 (0.10)

Source: ANRE[9]

Note: USD tariffs based on the average exchange rates current for the given year.

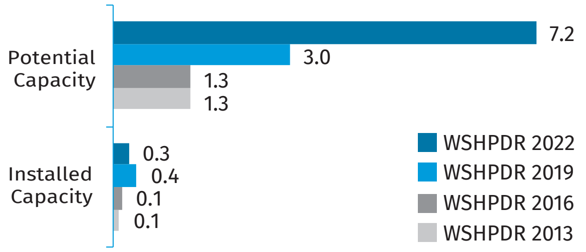
SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in the Republic of Moldova.[13] For the purposes of this chapter, SHP is defined as hydropower plants of up to 10 MW capacity.

As of 2021, there was only one SHP plant operating in Moldova, the SRL Hidroelectrica SHP plant on the Răut River with an installed capacity of 254 kW (Table 2). The plant has been allotted a tariff of 1.99 MDL/kWh (USD 0.11/kWh) for delivery of electricity to the grid.[14] The plant was constructed in 2017 on the site of a former water facility that had been abandoned since the 1960s. The plant's construction sparked controversy over the possibility that it had caused the significant decrease in water levels in the Răut River observed the same year.[15,16]

There are no recent nation-wide estimates of SHP potential in Moldova. However, a pre-feasibility study presented in 2016 identified a technically feasible SHP potential of approximately 7 MW on the Răut River.[17] Taking this estimate into consideration in addition to the known potential sites on other rivers, total potential capacity can be estimated to be at least 7.20 MW. Of this total, existing and previously operational SHP sites as well as those under consideration for SHP construction account for 2.17 MW. Figure 4 displays the installed and potential capacities of SHP in Moldova relative to previous editions of the *World Small Hydropower Development Report (WSHPDR)*. The decrease in installed capacity and increase in SHP potential relative to the *WSHPDR 2019* represent a more accurate interpretation of the available data, as no changes have taken place in practical terms.[14,17,18,19]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Moldova (MW)**



Source: AAE,[14] Pleșca, Pleșca, & Pleșca,[17] Ambros & Ursatii,[18] *WSHPDR 2019*,[19] *WSHPDR 2013*,[20] *WSHPDR 2016*[21]

Table 2. **List of Operational Small Hydropower Plants in Moldova**

Name	*Location*	*Capacity (kW)*	*Head*	*Plant type*	*Operator*	*Launch year*
SRL Hidroelectica	Telenești District, Brînzenii Noi	254	N/A	Run-of-river	SRL Hidroelectica	2017

Source: AAE[14]

In the 1960s, as many as 17 SHP plants were operational in Moldova and another 20 were planned for construction on various small rivers. However, all of these plants were dismantled or abandoned following the construction of large hydropower plants at Dubasari and Costeşti. Several of these non-functional micro-hydropower plants, with a combined capacity of 141 kW, remain in a serviceable state but require refurbishment. Identifiable former SHP sites that could potentially host new SHP projects also exist, with a total potential capacity of 575 kW. Proposals for new sites have been few, but a project involving several SHP plants was recently considered for a location near Trebujeni on the Răut River, with a potential capacity of 1.2 MW (Table 3).[13,14,18]

Table 3. **List of Selected Potential Small Hydropower Projects in Moldova**

Name	*Location*	*Potential capacity (kW)*	*Type of site*
Trebujeni	Răut River	1,200	New
Piatra/Jeloboc	Răut River	2 x 90	Reconstruction
Căzăneşti	Răut River	150	Reconstruction
Brânzeni	Răut River	126	Reconstruction
Vărvăreuca	Răut River	2 x 30	Refurbishment
N/A	Camenka River	57	Reconstruction
Vatra	Bâc River	2 x 22	Refurbishment
Vadul Turcului	Beloci River	32	Reconstruction
Ciuhur	Ciuhur River	30	Reconstruction
Corjeuţi	Lopatnic River	27	Refurbishment
CTŞ „Hidrotehnica”	Târnova	2 x 5	Refurbishment

Source: Ambros & Ursatii[18]

Overall, the rehabilitation of old SHP plants presents the most straightforward route to taking advantage of the existing SHP potential in Moldova and the most likely to be adopted by the private sector. Evaluations of the potential for the rehabilitation of old SHP plants and construction of new plants on the Răut River allow for the operation of approximately 20 mini-hydropower plants, with the average head of each plant at approximately 3 metres. The first hydropower plants recommended for rehabilitation are the ones in Piatra and Trebujeni, with a head of 4–5 metres and a potential capacity of 200–300 kW each.[17]

RENEWABLE ENERGY POLICY

In 2010, the Republic of Moldova became a full-fledged member of the Energy Community, committing itself to unifying its legal framework with the core European Union (EU) energy legislation and the so-called energy "acquis communautaire", the total body of EU law applicable to Member States.[22]

The National Development Strategy "Moldova 2030", adopted on 26 November 2018, outlined the need for economic development in line with principles of environmental security and sustainable use of natural resources.[23] In recent years, the Government has approved several pieces of legislation in support of these goals, including the following:

- Government Decision No. 698 of 27 December 2019 on the approval of the National Energy Efficiency Action Plan for 2019–2021;
- Government Decision No. 45 of 30 January 2019 on the organization and functioning of the Agency for Energy Efficiency;

- Law No. 139 of 19 July 2018 on energy efficiency;
- Government Decision No. 690 of 11 July 2018 on the Approval of the Regulations regarding the organization of tenders for offering the status of an eligible producer;
- Decision of the Board of Directors of ANRE No. 375/2017 of 28 September 2017 on the Methodology for determining fixed tariffs and prices for electricity produced by eligible producers from renewable energy sources;
- Law No. 10 of 26 February 2016 on the Promotion of the Use of Energy from Renewable Sources;
- Government Decision No. 301 of 24 April 2014 regarding the approval of the Environmental Strategy for 2014–2023 and of the Action Plan for its implementation;
- Government Decision No. 1073 of 27 December 2013 on the approval of the National Action Plan in the field of Renewable Energy for 2013–2020.

In March 2018, the Law on the Promotion of the Use of Energy from Renewable Sources entered into force.[24] The law transposes Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources. Capacity limits have been set in accordance with Government Decision No. 689 of 11 July 2018 regarding the approval of capacity limits, maximum quotas and capacity categories in the field of electricity from renewable sources until 2020 (Table 4).

Table 4. **Capacity Limits, Maximum Allowances and Capacity Categories for Renewable Energy Support Schemes in Moldova**

Technology	*Allotted capacity quota (MW)*			*Capacity limit (MW)*
	Total	*Using feed-in tariffs*	*Using fixed price established by tender*	
Wind power	100	20	80	4
Solar PV	40	15	25	1
Biogas	20	12	8	1
Cogeneration (using solid biomass)	5	5	0	1
Hydropower	3	3	0	1
Total	**168**	**55**	**113**	-

Source: Government of the Republic of Moldova[25]

The capacity limits are used to decide on the support schemes. Eligible producers can use one of the available support schemes: net metering or feed-in tariffs (FITs).[26] The net metering support scheme has been introduced to encourage project owners to cover their own electricity consumption with renewable energy–based production units with a maximum capacity of up to 200 kW, including hydropower. Any excess, calculated over a one-year period, may be sold at the average price of the wholesale energy market. In 2019, a total of 127 projects were put into operation in the country using this support scheme, with a total capacity of 1.49 MW, while in 2020 another 269 projects were put into operation with a total capacity of 4.90 MW. All these projects use solar photovoltaic (PV) installations.[9] Requirements for hydropower projects are specified in the tender announcements.

The methodology for calculating the FIT support scheme was approved by ANRE Decision No. 375 of 28 September 2017. Only power plants with capacities between 10 kW and the capacity limit defined by the Government are eligible for the FIT support scheme. Based on this methodology, the ANRE Board of Directors approved the following prices and fixed tariffs for electricity produced from renewable energy sources:

- Solar PV – 1.88 MDL/kWh (0.11 USD/kWh);
- Wind power – 1.55 MDL/kWh (0.09 USD/kWh);
- Hydropower – 0.97 MDL/kWh (0.06 USD/kWh);
- Biogas cogeneration – 1.84 MDL/kWh (0.10 USD/kWh);
- Solid biomass cogeneration – 1.96 MDL/kWh (0.12 USD/kWh).[27]

The FITs are annually adjusted to account for the variable exchange rate between the national currency and the US dollar.

In 2020, the procedure for the selection of producers eligible for the fixed FIT support scheme was announced for the first time. As a result, 27 renewable energy power plants were certified for FITs as of 21 December 2020, including 20 solar PV power plants, 6 wind power plants and 1 plant based on biogas cogeneration.[28]

According to Law No. 10/2016 regarding the promotion of energy use from renewable sources, the Government will adopt a tender/auction system for the selection of renewable energy projects. The introduction of capacity tenders was tentatively scheduled for 2019 but did not take place. The tenders are planned to be organized by a commission appointed by the Government in accordance with the provisions of Article 35 Paragraph 2 of the aforementioned Law.[24]

SHP development is regulated by the same legislation as other renewable energy sources. Similarly, SHP plants are eligible for the support schemes of net metering, FITs and tenders/auctions. Development of renewable energy projects in Moldova involves the following steps:

- Establishing a company and registering property rights (if necessary);
- Changing the land designation from agricultural land to land for construction purposes and obtaining an Urban Planning Certificate for Design Documentation;
- Developing technical conditions for connecting to utility networks as well as a Networks Routing Plan, conducting a topographical study and geotechnical prospecting, obtaining an Environmental Permit and carrying out an Environmental Impact Assessment;

- Preparing a detailed technical design and obtaining its verification and approval;
- Obtaining an authorization for construction;
- Registering with the fixed price or the fixed tariff support scheme;
- Obtaining approval to build a new renewable energy power plant and notifying the Agency for Technical Supervision of the launch of construction;
- Following construction and connection to the power transmission or distribution network, conducting post-construction assessments and obtaining approval of completed works;
- Obtaining a power generation licence;
- Signing an electricity supply contract;
- Registering the licence with the system operator and entry into force of the electricity supply contract and beginning of the operational phase.[29]

COST OF SMALL HYDROPOWER DEVELOPMENT

Development costs of SHP projects in Moldova are regulated by ANRE Decision No. 54/2020 of 28 February 2020 on fixed tariffs and prices for electricity produced from renewable energy sources. This document establishes the basic values used for calculating fixed tariffs and ceiling prices for electricity produced from renewable energy sources. For hydropower plants, the following coefficients and costs apply:

- Specific investment of 28,629 MDL/kW (1,662 USD/kW) — the maximum permissible cost per kilowatt of installed capacity of the commissioned SHP plant;
- Specific fixed maintenance and operating expenses of 3 per cent per year — the maximum permissible fraction of the total cost of the plant to be spent on maintenance and operation per year;
- Specific variable maintenance and operating expenses — no limit set, allowing the operators to decide the cap for these expenses on an individual basis;
- Capacity factor of 50 per cent, representing the minimum permissible value;
- Guarantee of participation of 54.7 MDL/kW (3 USD/kW) and guarantee of proper execution of 546.7 MDL/kW (30.4 USD/kW), representing a deposit submitted by the developer selected during the tender process. Following commissioning of the plant, the funds are unfrozen and accessible to the developer without conditions.[30]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

According to the Organisation for Economic Co-operation and Development (OECD) Small Business Act Moldova country profile, some progress has been made between 2012 and 2021 in providing support to and increasing the competitiveness of small and medium-sized enterprises (SMEs) in the country.[31] Despite these efforts, there remain limitations in terms of public support for SMEs, including SHP plants, with regard to innovation, greening and access to both bank and non-bank finance. Local commercial banks are cautious about investing in the renewable energy sector, due to their perception of such projects as high-risk, which partly stems from the general limited understanding of renewable energy technologies. As such, the main financing support comes from international financing institutions and local funds created with donor support.

The European Bank for Reconstruction and Development (EBRD), one of the major investors in the energy sector in Moldova, has implemented two programmes to support local energy projects: Moldovan Sustainable Energy Financing Facility II (MoSEFF II) and Moldovan Residential Energy Efficiency Financing Facility (MoREEFF). These projects provided credit lines to local banks for the re-accreditation of energy efficiency projects and sustainable investments in the energy sector. Additionally, in 2020 the EBRD and the Green Climate Fund (GCF) began promoting green finance in the country. Support for green technologies in Moldova includes a recent EUR 5 million (USD 5.95 million) loan provided by the EBRD and the Covenant of Mayors.[32]

The Covenant of Mayors, the world's largest initiative for local climate and energy actions, has been active in Moldova since 2009. Sixty-two municipalities in the country had signed the covenant as of 2020, committing themselves to submitting a Sustainable Energy and Climate Action Plan (SECAP) within two years of signing, of which 22 have additionally committed themselves to reducing municipal CO_2 emissions by 30 per cent by 2030. With this goal in mind, a total of EUR 970 million (USD 1,154.89 million) in investments is planned in various sectors in Moldova, of which 26 per cent is to be allocated towards local electricity production from renewable energy sources.[33,34]

The Energy Efficiency Agency (AEE) is a key local stakeholder in implementing state policy, national strategies and programmes in the energy efficiency and renewable energy in Moldova. Following an institutional reform in 2018, the AEE has been responsible for providing financial support to the sector — in part through funds allocated from the state budget, but also through additional funds to be raised on local, regional and international financial markets.[35]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The negative impacts of climate change present challenges for the country's economic development, directly and indirectly affecting the sectors based on natural resources such as energy, transport and industry. Of particular relevance to hydropower is the precarious nature of the country's surface water resources. Analysis of national climatic data indicates that the 10-year drought frequency in Moldova is approximately 1–2 droughts in the north of the country, 2-3 droughts in the centre and 5–6 droughts in the south.

Projections of changes in runoff in the lower part of the Dniester River basin, which includes most of the territory of Moldova, estimate decreases of up to 25 per cent in both average and minimum runoff by 2050, relative to the baseline period 1971–2000. Even without significant changes in runoff, increasing temperatures and drought frequency will likely drive water demand from the agricultural sector up.[36] This might put additional pressure on the water resources available for hydropower.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In recent years, Moldova has intensified its efforts to develop renewable energy sources, with a focus on the adoption of new support schemes for renewable electricity generation. This has significantly contributed to the growing interest in renewable energy sources from local and international investors. However, further efforts are needed to remove barriers to the implementation of renewable energy projects in the country, particularly with regard to SHP, including the following:

- Financial barriers: Lack of long-term funding, together with high cost of capital and collateral guarantees;
- Technical barriers: Lack of local technologies required for SHP projects, leading to a dependence on high-cost imports;
- Lack of capacity: Technical capabilities, experience and knowledge are limited. The lack of technical skills is further compounded by the fact that the necessary technologies are not used and promoted in the country.

A number of factors encouraging the development of SHP in Moldova also exist. These include:

- Political: The legal framework necessary for SHP development, including laws, regulations and procedures, is well-developed and mature;
- Social: SHP projects have a low profile in the country due to lack of development and do not face significant social opposition;
- Market: The energy sector is growing constantly and electricity consumption is increasing in all the main sectors of the economy, driving demand for additional energy sources;
- Financial: Subsidies and support schemes for SHP are well-established and the current lack of SHP projects means that allocated quotas are still available. In addition, financing for renewable energy projects is potentially available from a number of international institutions.

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Poland

Ewa Malicka, Polish Association for Small Hydropower Development (TRMEW)

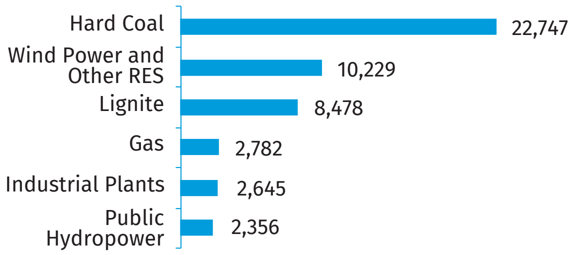
KEY FACTS

Population	38,354,173 (2020)[1]
Area	312,705 km^2 [2]
Topography	Poland is a lowland country with the majority of its land located lower than 300 metres above sea level. The highest point is Mount Rysy, at 2,499 metres above sea level. In Poland, there are four basic morphogenetic zones: the Carpathian Mountains with valleys, the old Sudetes with uplands, the area of central Poland and the littoral and lake regions. Most of the country's area is located in the Vistula and the Oder River basins. The Baltic Sea marks the northern border of the country and the ridges of the Carpathian Mountains and the Sudetes constitute its southern border.[3]
Climate	A border between the zones of moderate and subarctic climates and between oceanic and continental climates runs across Poland, causing a large amount of variability in its weather. Average annual temperature ranges between 6.5 °C and 8.5 °C. The coldest month is January, with average temperatures between -1 °C and -5 °C. The warmest month is July, with average temperatures between 16.5 °C and 18.5 °C. The number of days with temperatures below 0 °C in a year ranges between 90 and 130, although it is over 200 days in the mountains. The number of days with temperatures above 25 °C ranges between 5 and 40.[3]
Climate Change	Since the end of the 19th century, a systematic trend of rising temperatures has been observed in Poland, with a significant increase since 1989. The average yearly temperature in the years 1779–2000 was 7.7 °C, whereas for the two last decades of the 20th century and the first decade of the 21st century the average yearly temperatures were 8.7 °C, 8.9 °C and 9.2 °C for the respective three decades. Moreover, since 1989, several years recorded the highest average yearly temperatures since records began, including 2008 with an average temperature of 10.2 °C, 2000 with 10.0 °C and 1989 with 9.8 °C. The consequences of global warming observed in Poland include the intensification of extreme weather phenomena such as droughts, hurricane-force winds, tornadoes and hail, causing a noticeable change in the climate dynamics. Structural changes in precipitation have been observed in the warm seasons. Specifically, rainfall events have become both shorter and more extreme, with an elevated flood risk, while rainfall events below 1 mm per day are becoming rare. The results of analyses of climate scenarios for Poland in the 21st century show increasing temperatures across the country, extended periods without rainfall, increased number of maximum rainfalls and shorter snow cover periods. By 2071–2090, average annual temperature is expected to increase to 10.6 °C, while the average number of days per year with a maximum temperature of above 25 °C is expected to increase to 52, up from 27 in 1980–1991.[4]
Rain Pattern	The amount of precipitation depends on the region. It is highest in the mountains, with an annual average between 1,500 mm and 2,000 mm. In the valleys and uplands, it ranges from 400 mm to 750 mm, while the Wielkopolska region receives the lowest amount of rainfall (300 mm). The average rainfall in the whole country is approximately 600 mm, with the majority occurring in the summer months.[3]
Hydrology	Approximately 99.7 per cent of Poland belongs to the Baltic Sea drainage basin, which is in turn composed of the Vistula water basin (55.7 per cent), the Oder water basin (33.9 per cent) and the Neman water basin (0.8 per cent). Another 9.3 per cent constitutes the direct water basin of the Baltic Sea. The river network in Poland is asymmetrical with large water basins east of the Vistula and Oder Rivers, mainly because of its topographic slopes towards the north-west. The longest rivers are the Vistula (1,047 km), Oder (854 km), Warta (808 km) and Bug (772 km). Poland has approximately 9,300 lakes larger than 0.01 km^2, which altogether cover an area of 3,200 km^2 (approximately 1 per cent of the country's territory) and have a capacity of 17.4 km^3.[3]

ELECTRICITY SECTOR OVERVIEW

In 2020, the installed capacity in the National Electricity System of Poland was 49,238 MW, indicating a 5 per cent increase from 46,799 MW in 2019.[5,6] Thermal power (hard coal, lignite and gas) accounted for 34,008 MW (69 per cent of the total), wind energy and other renewable energy sources for 10,229 MW (21 per cent), industrial plants for 2,645 MW (5 per cent) and public hydropower plants for 2,356 MW (5 per cent) (Figure 1).[5]

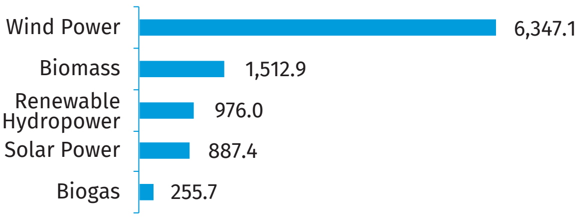
Figure 1. **Installed Electricity Capacity by Source in Poland in 2020 (MW)**



Source: PSE[5]

By the end of 2020, renewable energy capacity in Poland for installations enrolled in various support schemes (not including prosumers) reached 9,979 MW. Of this wind power supplied almost 64 per cent, biomass 15 per cent, renewable hydropower (hydropower plants generating electricity from the natural flow of water and excluding pumped storage plants) almost 10 per cent, solar power 9 per cent, and biogas 3 per cent (Figure 2).[7]

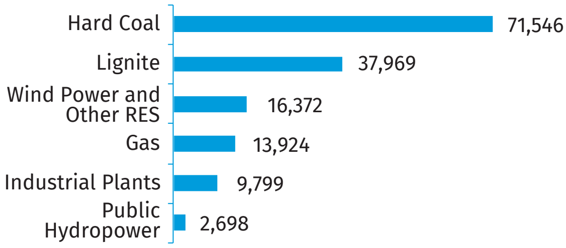
Figure 2. **Installed Renewable Energy Capacity by Source in Poland in 2020 (MW)**



Source: URE[7]

Total gross electricity generation in 2020 was 152,308 GWh and gross electricity consumption was 165,532 GWh.[5] The majority of generation in Poland is still based on conventional fuels, particularly hard coal and lignite. These contributed 72 per cent of total gross electricity generation in 2020 (Figure 3), though their share is decreasing year on year. In 2020, the share of energy from renewable energy sources in gross electricity consumption accounted for 11 per cent.[5] The electrification rate and grid availability in Poland is 100 per cent.[8]

Figure 3. **Annual Electricity Generation by Source in Poland in 2020 (GWh)**



Source: PSE[5]

The number and structure of electricity generating plants in Poland have not changed significantly over the last 5 years. In 2019, three companies, PGE Polska Grupa Energetyczna S.A., TAURON Polska Energia S.A. and ENEA S.A., held in total almost two-thirds of the country's installed capacity, provided almost 67 per cent of total electricity generation and over 66 per cent of the electricity fed into the grid.[6] Most of the power companies in the country continue to be owned by the State Treasury.

In Poland, there is one transmission system operator for electricity — PSE S.A, which is wholly owned by the State Treasury. PSE S.A.'s assets comprise the transmission grid, consisting of 281 lines of a total length of 15,316 km, 109 extra-high-voltage stations and a submarine 450 kV DC link between Poland and Sweden (254 km long).[9] In 2019, there were 189 distribution system operators (DSOs) involved in electricity distribution on the electricity market, including five large DSOs whose networks are directly connected to the transmission network. Large DSOs are legally obliged to separate the distribution activities carried out by the system operator from other activities not related to electricity distribution (unbundling).[6]

The biggest projects in the energy sector completed since 2018 include two new 900 MW coal-fuelled power plant units in Opole and one 910 MW unit in Jaworzno.[10] With regard to renewable energy, there is a noticeable increase in solar photovoltaic (PV) installations being put into operation, compared to the previous years. For example, between January 2020 and November 2020, the installed capacity of solar PV plants increased from 1,299.6 MW to 3,420.4MW.[11]

The ongoing development of the electricity sector includes an additional 20 GW of capacity either under construction or in the planning stages, represented primarily by coal- and gas-fired thermal plants. However, the ongoing projects also include one large hydropower plant on the Vistula River with a capacity of 80 MW, the country's first nuclear power plant with two units of 3,000 MW each and nearly 7,000 MW of offshore wind power plants located in the Baltic Sea.[10]

The Polish Energy Regulatory Office, an independent agency, is responsible for the regulation of the electricity, gas and heating markets. This includes licensing, approving investment plans by regulated companies, deregulation of the electricity and gas markets, oversight of the quality of supply and customer service as well as setting tariffs.[6]

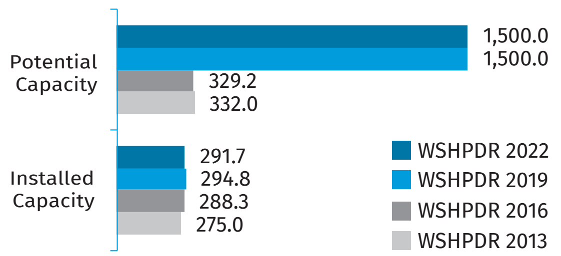
End users are entitled to receive electricity from a chosen supplier in an uninterrupted and reliable manner. In 2019, there were 5 default suppliers and 136 alternative trading companies actively selling electricity to final consumers. There are four electricity tariff groups in Poland. Groups A and B are for industrial users (supplied on the high- and medium-voltage grids), group C is for commercial users (connected to the low-voltage grid) and group G is for residential users. In 2019, there were 17.8 million consumers in the retail electricity market, out of which 91 per cent were in the G tariff group. Since 2008, the prices for companies using tariffs under groups A, B and C have remained unregulated, while the G tariff group (for households) is still subject to regulation. In the last quarter of 2019, the medium price of electricity in the retail market increased by 3.7 per cent as compared to the last quarter of 2016 as a consequence of the increase in costs of CO_2 emissions. It amounted to 477 PLN/MWh (130.3 USD/MWh), of which PLN 278 (USD 75.9) constituted the price of energy and PLN 199 (USD 54.4) constituted the distribution fee.[6]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in Poland; however, plants with a total capacity of up to 5 MW are customarily included in this category.[12] The operational definition of SHP used in the current chapter is up to 10 MW.

At the end of 2020, Poland had 782 renewable hydropower plants. Of these, 772 were SHP plants of up to 10 MW with a combined installed capacity of 291.7 MW (Table 1). Thus, SHP plants represented 30 per cent of the total hydropower capacity in the country in 2020. The installed capacity of SHP decreased by approximately 1 per cent relative to the *World Small Hydropower Development (WSHPDR) 2019*, whereas the potential has remained unchanged (Figure 4).[7,13,14,15] In 2020, electricity generation from SHP up to 10 MW was 949.7 GWh.[16]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Poland (MW)**



Source: URE,[13] ESHA,[14] *WSHPDR 2019*,[15] *WSHPDR 2013*,[17] *WSHPDR 2016*[18]

The total theoretical hydropower potential of Polish rivers has been estimated to be 23.6 TWh/year, with a technical potential of 13.7 TWh/year.[19,20] Out of this, the technical hydropower potential of SHP (up to 10 MW) is estimated to be approximately 5 TWh/year, corresponding to at least 1,500 MW of potential installed capacity.[12,14] This indicates that less than 20 per cent of the country's technical SHP potential has been developed so far. It is also estimated that approximately 50 per cent (2.5 TWh or 735 MW) of this potential is economically feasible.[12,14]

Hydropower potential in Poland is characterized by an uneven distribution throughout the country with 68 per cent of resources concentrated in the Vistula River basin, half of which is located in the lower Vistula region and 17.6 per cent in the Oder River basin. The rivers with the largest hydropower potential are the Vistula, Dunajec, San, Bug, Oder, Bóbr and Warta. The most favourable regions for hydropower development are the south of Poland (mountainous areas) as well as the west and north (due to existing non-powered water infrastructure).[21]

Table 1. **List of Selected Existing Small Hydropower Plants in Poland**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant Type*	*Operator*	*Launch year*
Bronocice	Nidzica River	0.037	2.7	Run-of-river	N/A	2015
Witulin	Świślina River	0.220	9.0	Run-of-river	N/A	2015
Brudnice	Wkra River	0.110	2.6	Run-of-river	N/A	2017
Słowik	Bobrza River	0.370	2.5	Run-of-river	N/A	2018
Świnna Poręba	Skawa River	4.400	N/A	Reservoir	PGW Wody Polskie	2019
Starogard Gdański	Wierzyca River	0.110	4.9	Run-of-river	N/A	2019
N/A	N/A	0.740	N/A	Run-of-river	N/A	2018-2020
N/A	N/A	0.132	N/A	Run-of-river	N/A	2018-2020
N/A	N/A	0.090	N/A	Run-of-river	N/A	2018-2020
N/A	N/A	0.498	N/A	Run-of-river	N/A	2018-2020
N/A	N/A	0.945	N/A	Run-of-river	N/A	2018-2020
N/A	N/A	0.499	N/A	Run-of-river	N/A	2018-2020
N/A	N/A	1.200	N/A	Run-of-river	N/A	2018-2020
N/A	N/A	2.100	N/A	Run-of-river	N/A	2018-2020
N/A	N/A	0.495	N/A	Run-of-river	N/A	2018-2020
N/A	N/A	0.090	N/A	Run-of-river	N/A	2018-2020

Name	Location	Capacity (MW)	Head (m)	Plant Type	Operator	Launch year
N/A	N/A	0.320	N/A	Run-of-river	N/A	2018-2020
N/A	N/A	2.400	N/A	Run-of-river	N/A	2018-2020

Source: TRMEW[22]

In the 1920s and 1930s, there were over 8,000 hydropower facilities in Poland, including many different types of mills and some hydropower plants. Only 2,131 of these installations remained by the 1980s, of which only 300 were in use at the time.[19] The possibility of repowering these historic sites is being considered as an economically feasible and environmentally sustainable form of small and micro-hydropower generation both by the Government and non-governmental organizations. The RESTOR Hydro Map, created through the Intelligent Energy Europe Programme of the European Union (EU), identifies over 8,500 historical sites in Poland as potential locations for small and micro-hydropower plants.[23]

Several planned SHP projects with a prospective launch date in 2023 are listed in Table 2. A selection of potential sites for future SHP investment is displayed in Table 3.

Table 2. **List of Selected Planned Small Hydropower Projects in Poland**

Name	Location	Capacity (MW)	Plant type	Developer	Planned launch year
N/A	Holy Cross Voivodeship	0.037	Run-of-river	Private	2023
N/A	Lesser Poland Voivodeship	0.110	Run-of-river	Private	2023
N/A	Warmian-Masurian Voivodeship	0.037	Run-of-river	Private	2023
N/A	Pomeranian Voivodeship	0.055	Run-of-river	Private	2023
N/A	Lubusz Voivodeship	0.075	Run-of-river	Private	2023

Source: TRMEW[22]

Table 3. **List of Selected Potential Small Hydropower Sites in Poland**

Name	Location	Potential capacity (MW)	Plant Type	Type of site (new/refurbishment)
N/A	Warmian-Masurian Voivodeship	0.045	Run-of-river	New
N/A	Masovian Voivodeship	0.055	Run-of-river	New
N/A	Lower Silesian Voivodeship	0.200	Run-of-river	New
N/A	West Pomeranian Voivodeship	0.075	Run-of-river	New
N/A	Opole Voivoideship	0.160	Run-of-river	New

Source: TRMEW[22]

RENEWABLE ENERGY POLICY

Although Poland refers to sustainable development in its constitution (Constitution of Poland, Article 5), the electricity sector is still largely based on carbon-intensive fossil fuels, and renewable energy sources do not play a significant role for decision-makers. At the EU level, Poland continuously opposes more ambitious greenhouse gas reduction targets and further developments of climate change policies, including the European Green Deal.[24] The main energy policy objective in the field of renewable energy sources, and the country's binding target based on the EU 2020 Climate and Energy Package, was to increase the share of renewable energy sources in total energy consumption to at least 15 per cent by 2020 and to further increase it in the following years. This initial target has been achieved, with the share of renewable sources in gross final energy consumption in Poland in 2020 (including the electricity, transport, heating and cooling sectors) slightly exceeding 16 per cent.[16]

The long-term energy strategy of Poland is determined by the Energy Policy of Poland until 2030 (adopted in 2009).[25] As of the moment of writing of this chapter, an updated long-term energy policy document, the Energy Policy of Poland until 2040, was under development, with its latest draft having been presented by the Minister of Climate and Environment on 8 September 2020.[26]

Until 1 July 2016, the support mechanisms for renewable energy sources were based on tradeable green certificates and an obligation of purchase of electricity by the appointed energy entities. On 20 February 2015, the Act on Renewable Energy Sources was adopted in Poland, introducing a support scheme based on tendering (auctions). In the new scheme, reference (maximum) prices are defined for each technology and additionally within each technology for installations with capacity up to 1 MW and for those above 1 MW. Likewise, auctions are conducted separately for existing and new installations with capacity of up to 1 MW and for those above 1 MW. Producers who win the tender have the right to receive the offered price for a period of 15 years.[27] Since 2015, there have been several amendments to the Act on Renewable Energy Sources. These introduced numerous changes in the support mechanisms, including options for micro-producers (prosumers) offering them discounts on electricity purchased from the grid in return for the electricity fed into the grid as well as in the tendering rules. Finally, in 2018 feed-in tariffs (FITs) and feed-in premiums (FIPs) were adopted for SHP and biogas plants, for both new and existing projects with an installed capacity below 1 MW.[28]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The main regulations in Poland related to SHP include the Act on Renewable Energy Sources and the Energy Law (which outline rules of electricity production and support schemes for renewable electricity producers), the Water Law, the Water Basin Management Plans and the Conditions of Water Use in Water Regions (which outline rules of water management, water use for hydropower purposes, rules for water installations, requirements for residual flow, fish migration and some restrictions in developing new hydropower projects in line with the EU Water Framework Directive). Additional regulations include the Act on Nature Protection and the Act on Accessibility of Information concerning the Environment and its Protection, Participation of the Society in Protection of the Environment and Assessment of Impact on the Environment.

The licensing process for SHP in Poland consists of several steps. Firstly, the environmental impact of the project needs to be evaluated and an environmental decision needs to be obtained. Furthermore, a decision on building conditions is required, which is issued by the local administration, with the exception of rare cases where there is a spatial development plan covering the investment area. A water-legal assessment and permission need to be obtained from the water authority. The next important stage is to acquire rights to manage the real estate as a property of the State Treasury, including lands covered with running water and usually including the weir. These rights are acquired from the water authority which is responsible for the maintenance and ownership supervision over the estate. The finishing juncture of the procedure is to acquire a permit for construction through an application to the powiat (county-level) or the voivodeship (province-level) authority. Additionally, a decision on the terms and conditions of grid connection, and subsequently a grid connection agreement, must be obtained from the system operator in order to start operation. In Poland, nearly all SHP plants are connected to the grid and there are very few off-grid installations. Finally, the concession to produce electricity from a renewable energy source issued by the Energy Regulatory Office will be needed for plants with an installed capacity exceeding 500 kW. Installations with capacities of 50–500 kW require a registration as an electricity producer in small installation. In case of micro-producers, only a notification to the local system operator is required.[29]

COST OF SMALL HYDROPOWER DEVELOPMENT

The majority of hydropower plants in Poland fall into the categories of small and micro-hydropower. In 2020, out of a total number of 782 hydropower plants existing in the country, 704 were up to 1 MW. Many of them are low-head and located on small streams. These factors set Polish hydropower plants among projects with a very high levelized cost of energy (LCOE). In 2020, the average investment cost of SHP development in Poland was PLN 21.3 million (USD 5.82 million) per MW installed, while the average operational cost was 1.79 million (USD 0.48 million) per year per MW installed. In the same year, the costs of power generation (including CAPEX and OPEX) for newly developed projects amounted to PLN 735 (USD 201) per MWh produced, PLN 774 (USD 211) in the case of plants with an installed capacity below 500 kW and PLN 665 (USD 181) for those ranging from 500 kW to 1 MW.[30] In terms of older plants, after their depreciation and the expiry of the support period (15 years) the average cost of generation (OPEX only) in 2020 amounted to PLN 524 (USD 143) per MWh produced in the case of plants with an installed capacity below 500 kW and PLN 381 (USD 104) in the case of plants ranging from 500 kW to 1 MW.[31]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Available funding options for SHP projects in Poland come from EU funds, the National Fund for Environmental Protection and Water Management, the Government of Norway (through the Green Industry Innovation Programme for Poland), the Rural Development Foundation and commercial banks.

Support schemes for new SHP projects include auctions, FITs and FIPs as well as discounts for prosumers in micro-installations. In 2020, the reference prices in auctions for hydropower amounted to PLN 620 (USD 170) per MWh for SHP plants with a capacity lower than 500 kW, PLN 560 (USD 153) per MWh for those with a capacity in the range between 500 kW and 1 MW and PLN 535 (USD 146) per MWh for hydropower plants with a capacity higher than 1 MW.[32] With the FITs and FIPs, which are the financial support schemes most commonly used by SHP producers, the guaranteed prices amount to 90 per cent of the reference prices assigned each year for auctions. Producers are entitled to the guaranteed price within auctions in either a FIT or a FIP for 15 years.[28]

The development of new projects has been difficult in recent years due to the gap between the closing of the green certificate system and the launch of new support schemes (auctions and FITs). As a result, between 1 July 2016 and 14 July 2018 there were no support schemes available for new hydropower projects.

Between mid-2018 and the end of 2020, several auctions were carried out for hydropower projects, but contracts were only won in auctions of hydropower plants with capacity higher than 1 MW (five contracts for new projects).[33] In the case of projects with lower capacities, there were not enough bids submitted as producers choose the FITs or FIPs instead. In 2018 and 2019, there were 343 existing SHP plants which switched from the certificate system or auctions to the FIT/FIP system, with a total installed capacity of 72 MW. At the same time, 15 permits were issued for new SHP projects to receive benefits from the FITs/FIPs.

As mentioned above, the total period of support for all renewable sources in Poland is limited to 15 years and includes the time of support under any system (green certificates, auctions, FIT/FIP). Due to the fact that the first support scheme (the green certificate system) was adopted in 2005, all existing plants which enrolled in this scheme that year have lost the right to any kind of support as of 2020. The number of such plants is 400 and their total installed capacity amounts to 127 MW. These plants now face serious financial challenges as the wholesale market prices for electricity are not sufficient to cover their generation costs (ranging from approximately PLN 194 (USD 53) to PLN 245 (USD 67) per MWh in the two previous years). The reduction of revenue together with the high costs of electricity generation have increased the risk of these plants ceasing operation. The Polish SHP sector has requested remedial measures, including an extension of the support period for small and micro-hydropower plants. At the moment of writing of this chapter, a draft law was in the works to extend the support period for SHP plants and biogas installations by two years.[34,35]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Poland is among the countries with low average water availability, low rate of water reservoir capacity and increasing problems with water uptake. These problems have been intensifying due to the effects of climate change and are already affecting the hydropower sector in the country.[4,36] Future impacts largely depend on the progress of climate change over the course of the century. A recent study modelled the hydrological conditions in the Lusatian Neisse River basin and their impact on electricity generation of German and Polish SHP plants located in the basin based on two different climate change scenarios (RCP2.6 and RCP8.5, representing moderate and extreme scenarios for solar radiation levels in 2100, respectively). It concluded that in terms of hydropower, both positive and negative outcomes are possible. Under the RCP2.6 scenario, generation could increase by as much as 6–7 per cent by 2100 relative to the period 2015–2020, while under the RCP8.5 scenario, generation was projected to decrease by 31–34 per cent by 2100 relative to 2015–2020 across most surveyed plants. The study warns of significant energy problems in the basin if the extreme climate scenario is realized.[37]

BARRIES AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In general, SHP development in Poland faces a large number of obstacles, including:

- Long-lasting, complicated and costly administrative procedures (especially in terms of environmental assessment) and lack of simplified procedures for small and micro-hydropower;
- High investment and operational costs of projects, resulting from the obligation of SHP plant operators to provide services connected to water regulation and maintenance of state-owned water facilities, channels and riverbeds as well as to continuously adapt throughout the whole lifespan of the plant to increasingly rigorous environmental requirements (e.g., building fish passes and fish barriers, increasing residual flow);
- Adoption of water pricing for hydropower since 2018 and the increase in fees paid for using damming structures and inundated lands owned by the state;
- Lack of effective and uniform regulations allowing the utilization of existing weirs for hydropower purposes;
- Support period of 15 years not adjusted to the lifespan of SHP projects (typically 60–70 years) and financial difficulties with the upkeep of SHP plants after the expiry of the support period;
- Lack of spatial development plans that include SHP;
- Lack of predictability of legal regulations and dependency on the regulated renewable energy market, which is especially difficult for small investors;
- Climate risk to hydropower in Poland under pessimistic climate change scenarios.

Enabling factors for SHP development in Poland include the following:

- The FIT/FIP scheme now offers support for newly constructed SHP plants;
- Very large number (over 8,500) of previously constructed water facilities across the country that could be refurbished or re-equipped as SHP plants;
- Possible increases in potential hydropower generation under optimistic climate change scenarios.

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Romania

Bogdan Popa and Eliza-Isabela Tica, University Politehnica of Bucharest

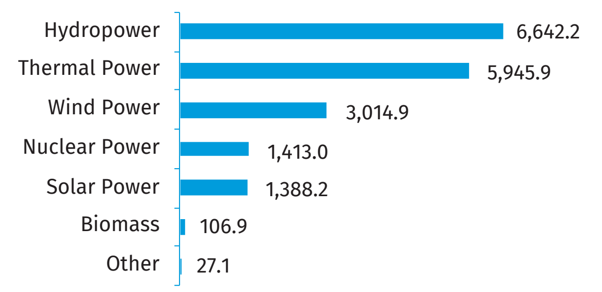
KEY FACTS

Population	19,186,000 (2021)[1]
Area	238,391 km^2 [2]
Topography	The landscape of Romania is composed of nearly equal shares of mountains (31 per cent), hills (33 per cent) and plains (36 per cent). The landscape slopes downward from the Carpathian Mountains reaching more than 2,400 metres above sea level to just a few metres above sea level at the Danube Delta.[3]
Climate	Romania has a temperate continental climate with four seasons. The winters are cold and cloudy with frequent snow and fog, while the summers are sunny with frequent showers and thunderstorms. The average temperature ranges between -11 °C and 10 °C in the southern part of the country and between -9°C and 8.5 °C in the north. Maximum average temperatures during the summer are between 22 °C and 24 °C and between -5 °C and -3 °C in the winter.[4,5]
Climate Change	Observations indicate an increase in scorching heat intensity in Romania over the last several decades. The scorching heat index increased from 13 units between 1961 and 1990 to 28 units between 1981 and 2010, with the maximum length of heatwaves also being on the rise. Projected climate change impacts include a rise in average monthly temperatures of up to 3 °C and a sharp (8–9 per cent) decrease in precipitation during the summer months between 2021 and 2051, relative to the 1961–1990 reference period.[6]
Rain Pattern	Precipitation in Romania follows a decreasing pattern from west to east and from higher to lower elevations. Some mountainous areas receive more than 1,010 mm of precipitation each year. Annual precipitation averages approximately 635 mm in central Transylvania, 521 mm at Iaşi in western Romania and only 381 mm at Constanţa on the Black Sea.[7]
Hydrology	The most important river of Romania is the Danube. Its lower course forms a delta that covers much of the north-eastern part of the Dobruja region. Most of the major rivers in the country are part of the Danube system, including the Mures, the Somes, the Olt, the Prut, and the Siret. Romania has many small, freshwater mountain lakes, as well as large saline and freshwater lagoons on the coast of the Black Sea. The largest of these is Lake Razelm.[4]

ELECTRICITY SECTOR OVERVIEW

The installed capacity of Romania as of March 2022 was 18,538.2 MW, decreasing from 20,582.0 MW in 2020. Hydropower provided 6,642.2 MW (36 per cent) of this total, thermal power provided 5,945.9 MW (32 per cent), wind power provided 3,014.9 MW (16 per cent), nuclear power provided 1,413.0 MW (8 per cent), solar power provided 1,388.2 MW (8 per cent) and biomass and other sources provided 134.0 MW (less than 1 per cent) (Figure 1).[8,9]

Figure 1. **Installed Electricity Capacity by Source in Romania in 2022 (MW)**

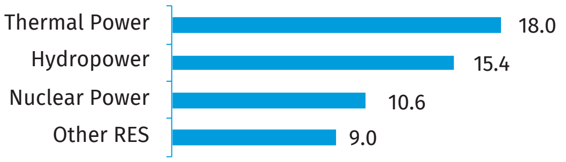


Source: ANRE[8]

The decrease in installed capacity since 2020 was a result of the continuation of measures taken by the National Energy Regulatory Authority (ANRE) during 2020 and 2021 to withdraw or amend some licences issued to producers with an installed capacity larger than their practically available capacity, based on their declarations of availability, to better reflect the actual situation in the power sector. Unavailable power units were then removed from the inventory of installed capacity, resulting in a significant reduction of the nationwide installed capacity total.

Total generation of electricity in Romania in 2020 reached 53.0 TWh, with 18.0 TWh (34 per cent) of the total provided by thermal power, 15.4 TWh (29 per cent) provided by hydropower, 10.6 TWh (20 per cent) provided by nuclear power and the remaining 9.0 TWh (17 per cent) provided by other renewable energy sources (RES) (Figure 2). The share of electricity generation in 2020 from RES, including hydropower, was 46 per cent.[9]

Figure 2. **Annual Electricity Generation by Source in Romania in 2020 (TWh)**



Source: Transelectrica[9]

Exports of electricity in 2020 amounted to 4.0 TWh, while imports were 6.8 TWh, with domestic consumption reaching 55.8 TWh.[9] Electricity access in Romania as of 2019 was 100 per cent.[10]

The capacities of the national grid of Romania have been challenged by the rapid development of wind and solar power concentrated in the south-eastern and eastern areas of the country, particularly in the Dobruja region. Consequently, grid access for new RES power plants has been increasingly restricted.[4]

Electricity distribution is organized according to several zones with a private electricity provider responsible for each zone: Banat (Enel), Transilvania Nord (Electrica), Transilvania Sud (Electrica), Oltenia (CEZ), Muntenia Sud (Enel), Muntenia Nord (Electrica), Moldova (E.On) and Dobruja (Enel). The Government regulates transmission and distribution tariffs for every region. Electricity tariffs for end users are differentiated based on voltage level rather than by sector or consumer category. The tariffs are updated by ANRE on an annual basis.[4,11] Regional generic electricity tariffs for July–December 2020 are displayed in Table 1.

Table 1. **Regional Generic Electricity Tariffs for July–December 2020**

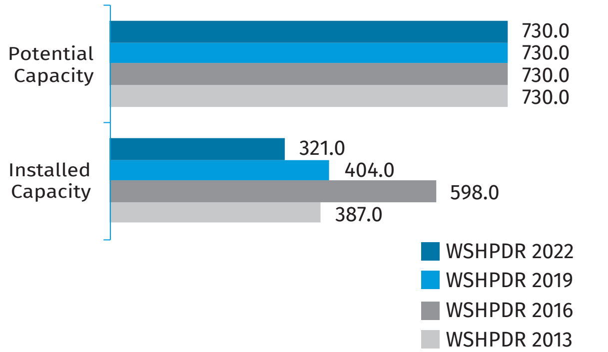
Region	*Price (RON/kWh (USD/kWh))*	
	Medium voltage	*Low voltage*
Banat	0.322 (0.071)	0.430 (0.095)
Dobrogea	0.302 (0.066)	0.433 (0.095)
Muntenia Sud	0.289 (0.063)	0.402 (0.088)
Moldova	0.318 (0.070)	0.448 (0.099)
Muntenia Nord	0.328 (0.072)	0.451 (0.099)
Transilvania Nord	0.343 (0.075)	0.447 (0.098)
Transilvania Sud	0.335 (0.074)	0.440 (0.097)
Oltenia	0.352 (0.077)	0.473 (0.104)

Source: ANRE[11]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Romania includes hydropower plants with an installed capacity up to 10 MW. In 2020, the total installed capacity of SHP in Romania accredited by ANRE was 321 MW provided by 103 plants, including 18 recently refurbished plants with a total capacity of 55 MW.[11] The potential capacity of SHP is estimated at 730 MW, indicating that approximately 44 per cent has been developed. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP in the country has decreased by nearly 21 per cent due to a reassessment of actual installed capacities of operating plants by ANRE, while estimates of potential capacity have remained the same (Figure 3).[4]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Romania (MW)**



Source: *WSHPDR 2019*,[4] ANRE,[11] *WSHPDR 2013*,[12] *WSHPDR 2016*[13]

The biggest hydropower potential in Romania is concentrated in the mountain areas, especially within the Carpathian Mountains Arch in the Transylvania region. The hydrographic basins most suitable for SHP development include the Mures, Arges, Buzau, Jiu, Crisurile, Nera and Siret River Basins.[4] A partial list of existing SHP plants in Romania is provided in Table 2.

Table 2. **List of Selected Existing Small Hydropower Plants in Romania**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Operator*	*Launch year*
Măneciu II	Măneciu	0.075	43.4	TOTAL TRANS SRL	2021
Măneciu I	Măneciu	0.269	N/A	TOTAL TRANS SRL	2021
Baraj Someș	Cuzdrioara	1.890	N/A	MHPP ENERGY SOMES SRL	2017
Valea Mare	Bistrița Năsăud	0.990	N/A	MHC Valea Mare SRL	2016
Secuș	Mureș county	1.123	N/A	BETONMIX SRL	2016
MHC C1 (Canciu)	Alba county	2.310	N/A	SC ENERGIS ROTT SRL	2016

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Operator*	*Launch year*
Viromet	Brașov country	0.395	N/A	VIROMET S.A.	2015
Zagra 1	Sat Suplai	0.402	N/A	ZAGRA HIDRO SA	2014
Zagra 2	Sat Suplai	0.331	N/A	ZAGRA HIDRO SA	2014
MHC C2 (Boșorogu)	Alba county	1.650	N/A	S.C. ROTT HAUS CONSULTING S.R.L.	2014
Răcătău	Măguri-Răcătau-Mărișel	1.600	123.6	RENOVATIO TRADING SRL	2013
Viștea	Brașov county	1.188	N/A	Vistea Hidroelectrica SRL	2013
Viștișoara	Brașov country	2.400	N/A	HIDRO CLEAR FAGARAS SRL	2013
Valea Minghetului Suciu	Groșii Țibleșului	0.995	N/A	HYDROTECH ELECTRIC SRL	2013
Valea Lui Vlad	Groșii Țibleșului	1.162	N/A	SC HIDROELECTRICA DEL VALEA LUI VLAD SRL	2013
Valea Stanciului	Mărgău	0.959	N/A	BETA ENERGIE REGENERABILA srl	2012
Valea Neagra 1	Firiza	1.760	N/A	S.C. IDROSEI S.A	2012
Valea Neagra 2	Firiza	0.800	N/A	S.C. IDROSEI S.A	2012
Vlahita	Harghita county	0.956	N/A	H2O ENERGY SA	2011
Zetea	Harghita county	3.960	N/A	UZINSIDER GENERAL CONTRACTOR S.A.	2007

Source: Transelectrica[14]

RENEWABLE ENERGY POLICY

The promotion scheme for RES project development was established by Law 220 from 2008. Initially, the promotion scheme issued one Green Certificate (GC) for each MWh generated from RES, including SHP, wind power, solar power, biomass, biogas and geothermal power, for a 15-year period. In 2010, the promotion scheme was changed, granting different numbers of GCs for each RES as follows: 3 GCs for new SHP plants and 2 GCs for refurbished SHP plants for a 10-year period, 2 GCs for wind power plants for the first 5 years and then 1 GC for the following 10 years, 6 GCs for solar power plants and 4 GCs for biomass and biogas plants. This change temporarily made Romania one of the most attractive countries in the European Union for RES investments.[4]

In 2013, the Government of Romania issued Emergency Ordinance No. 57/2013, which established modifications to the RES promotion scheme defined by the Law 220/2008.[15] Legal modifications, which affected the number of GCs and limitations in annual quotas, caused a large number of GCs to no longer be traded and resulted in RES producers being unable to transform this form of incentives into cash flow. The producers kept their untraded GCs, which caused the price of GCs on the market to drop from the maximum value established by the legislation of EUR 55 (USD 63) to the minimum value of EUR 30 (USD 34). Consequently, it has been difficult to attract financial support for green energy projects.

The Law 220/2008 was additionally modified with GD 994/2013 and several GCs for RES projects were delayed until 2017, 2018 and 2020 respectively. This decision was taken to reduce the impact on end-user electricity tariffs from the incentives granted to RES. However, the RES promotion scheme established by the Law 220/2008 ended in 2016 and subsequently only those RES projects that were commissioned before the end of 2016 were able to benefit from of the GC scheme, with the last issued GCs to run out in 2031. As a result, no large-scale RES projects have been developed or built since 2017.[4]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key issues hampering the development of SHP in Romania are as follows:

- No current legislation for the promotion of RES with GCs or other financial incentives, discouraging investors;
- Complex procedure for obtaining a water use permit and securing a location for SHP plant development. Obtaining water use rights requires the investor to first rent the necessary surface of the minor riverbed after a public tender and only then apply for a water use permit;
- Excessive cost of water for power generation making low-head SHP projects economically unfeasible;
- Opposition from environmental groups caused by a recent increase in SHP projects in upstream mountain areas;
- Lack of up-to-date estimates of countrywide SHP potential;
- Legislation significantly complicating access for RES projects to the national grid.

The primary enabler for SHP development in Romania is the significant undeveloped potential SHP capacity remaining in the country.

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Russian Federation

Galina Livingstone, Livingstone Environmental Ltd.

KEY FACTS

Population	146,493,388 (2020).[1]
Area	17,125,191 km^2 [2]
Topography	The topography of Russia includes broad plains with low hills found west of the Urals, vast coniferous forest and tundra in Siberia and uplands and mountains along the southern border regions. The highest point in Russia is Mount Elbrus (5,642 metres), which is also the highest point in Europe. The lowest locations are found near the shores of the Caspian Sea.[3]
Climate	The climate of Russia varies considerably owing to its extensive territory. The climate is humid continental climate in much of the European Plain area in the western part of Russia, subarctic in the Siberia region to the centre-north and tundra in the polar north. Winters vary from cool along the Black Sea coast to frigid in Siberia; summers vary from warm in the steppes to cool along the Arctic coast. The average temperature in January is -26.7 °C, varying from 0 °C in the North Caucasus to -50 °C in the Republic of Yakutia. The average temperature in July is 14.8 °C, but it can be as low as 1 °C in the northern coastal areas of Siberia and reach 25 °C in the Caspian region.[4]
Climate Change	Being one of the largest producers of fossil fuels in the world, Russia accounts for nearly 5 per cent of global CO_2 emissions. The recent increase in the mean annual temperature is approximately 2.5 times higher in Russia than the worldwide average. In the period 1976–2016, temperatures on average increased by 0.45 °C every 10 years, with the greatest rates of increase (0.72–0.77 °C) observed in Siberia in the spring and fall. This temperature increase is associated with serious environmental hazards, such as the thawing of permafrost, increase in the frequency of wildfires, peatland fires, flash floods, coastal flooding and increased soil erosion.[5]
Rain Pattern	The majority of the territory of Russia has little exposure to ocean influences. Most of the country receives low to moderate amounts of precipitation. The average annual precipitation in the country is 423 mm. Precipitation is highest in July (64.3 mm) and lowest in February (15.8 mm).[4] Most precipitation falls in the north-west, with amounts decreasing from north-west to south-east across European Russia.
Hydrology	There are over 2.5 million rivers, more than 2.7 million lakes and hundreds of thousands of wetlands on the territory of the Russian Federation. The total volume of static freshwater resources is estimated at 88,900 km^3, with a significant proportion represented by underground water. Russia possesses approximately 20 per cent of the world's freshwater resources, but this water is rather unevenly distributed within the territory. Approximately 90 per cent of the river flow volume in the country belongs to the Arctic basin. Thus, the central and southern regions of European Russia, where 80 per cent of the country's population and industry are concentrated, have only 10 per cent of freshwater resources.[6]

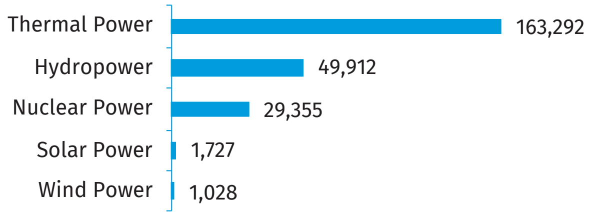
ELECTRICITY SECTOR OVERVIEW

Russia is one of the top producers and consumers of electric power in the world.[7] The Russian Federation Energy Strategy for the period up to 2035 assumes further increases of electric power consumption, particularly in the regions with accelerating economic development including the Russian Far East, the Russian North, Siberia and the Caspian region.[8] Russia has rich gas, oil and coal reserves, therefore, thermal power plants contribute the largest share of electricity generation, but nuclear power and hydropower also provide a significant contribution.

The United Energy System (UES) Group of Russia provides most of the country's electricity and exports power to neighbouring countries over the UES network. UES is the largest centrally controlled electric power system in the world, composed of 880 power plants of over 5 MW.[10] The UES of Russia works in parallel with the UES of Azerbaijan, Belarus, Georgia, Kazakhstan, Latvia, Lithuania, Mongolia, Ukraine and Estonia on the basis of bilateral agreements.[9,10] The Russian Federation is working together with other members of the Eurasian Economic Union towards the establishment of a joint energy market and transition to a coordinated energy policy.

As of 1 January 2021, the total installed capacity of UES power plants was 245,313 MW. Thermal power plants made up nearly 67 per cent of this total, hydropower 20 per cent, nuclear power 12 per cent and wind and solar power combined approximately 1 per cent (Figure 1).[11]

Figure 1. **Installed Electricity Capacity by Source in Russia in 2021 (MW)**

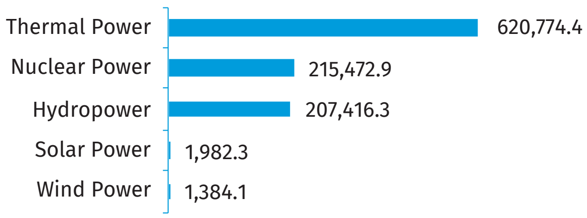


Source: UES System Operator[11]

Hydropower plants are one of the key components of the UES, providing over 90 per cent of the regulated power capacity reserve.[11] The federal hydropower generation company, PJSC RusHydro, owns the majority of the hydropower plants in the country. As of 31 December 2020, the Government of the Russian Federation owned approximately 62 per cent of the RusHydro share capital.[12]

Total net electricity generation in 2020 was 1,047 TWh, of which thermal power including industrial power plants provided 59 per cent, nuclear power plants 21 per cent, hydropower plants 20 per cent, and solar and wind power plants combined less than 1 per cent (Figure 2).[9]

Figure 2. **Annual Electricity Generation by Source in Russia in 2020 (GWh)**



Source: UES System Operator[9]

Total electricity consumption in 2020 was 1,033 TWh. Relative to 2019, electricity generation decreased by 3 per cent, while consumption decreased by approximately 2 per cent.[9] The decrease in generation and consumption was partially a result of cuts in oil output as part of the OPEC+ (Organization of the Petroleum Exporting Countries and allies) agreement of 2020, reducing power demand by oil pipelines, and partially due to an overall decrease in economic activity caused by COVID-19. The latter is expected to continue to impact electricity demand and production in Russia beyond 2021.

The power distribution is performed over more than 10,700 electric transmission lines of 110–1,150 kV and controlled by 7 major regional Joint Energy Systems spread across the 85 federal subjects of Russia. PJSC Rosseti is the main operator of energy grids in Russia. The company maintains 2.37 million kilometres of power transmission lines and 517,000 substations with transformer capacity of more than 802 GW (2019). The controlling shareholder of the company is the Federal Agency for State Property Management of the Russian Federation, which owns 88 per cent of the share capital.[13] The UES Federal Grid Company (FGC UES), a subsidiary of PJSC Rosseti, acts as the operator and manager of the Unified National Electric Grid (UNEG) of Russia, including the high-voltage transmission lines.[14] The FGC UES is responsible for transmission of power over the electrical grids and provision of technological connections to the electrical grid for electricity consumers, generating power plants and the transmission facilities of other owners. These activities are both natural monopolies and therefore regulated by the state.

The electrification rate in Russia is 100 per cent.[15] The country was ranked seventh in the world by availability of electricity by the World Bank in 2019 and scored eighth out of eight in power supply reliability and transparency of tariffs.[16] However, several structural problems with providing energy to consumers still exist. For example, many settlements located in sparsely populated areas such as the Russian North, Siberia and Far East are not connected to UNEG.[17] These regions rely on the local power generation facilities and imported fuel for power plants. Yakutia is a typical example of such a region; the local company, PJSC SakhaEnergo, supplies electric power to an area of approximately 2.4 million km^2 occupied by a population of about 105,000, mostly by means of 136 autonomous diesel power plants.[18] As a consequence of the collapse of the Soviet Union energy management system, some minor grids in remote areas have no registered owner at all; the Government is currently discussing returning these to state ownership.

There are several regions in the country classified by the Russian Federation Energy Ministry as being at high risk of electric power supply interruption, including Dagestan, Irkutsk oblast' and others. These risks arise mostly due to an insufficient local power infrastructure. The Energy Ministry is implementing plans for mitigating such risks.[19] As such, modernization of existing generation capacities and implementation of new generating technologies, including an accelerated development of renewable energy capacities, are key strategic objectives for the Russian electricity industry. Federal Law on the Electric Power Energy Industry No. 196-FZ was updated in 2016 by the inclusion of enhanced requirements for the reliability and safety of the electric power facilities and distribution systems.[20] Russian electricity consumption is expected to increase by 1.1 per cent per year on average in 2020–2026.[21]

The Russian electricity market consists of wholesale and retail markets. Liberalization reform plans for the Russian electricity market assume a future transition to a fully non-regulated electric power market. However, liberalization currently applies only to the wholesale sector, where most of the electricity is now traded at non-regulated market prices. Public tariffs are likely to remain state-regulated for the foreseeable future. For electricity price control, the country is split into two market price zones (European Russia–Ural zone and Siberia) as well as the non-price zones (Kaliningrad oblast', Far East, Arkhangelsk oblast' and the Komi Republic) (Figure 3). The reason for such division is a limited capacity of interconnection between these zones within UNEG and different structures of the production capacity, e.g., predominance of relatively cheap hydropower in Siberia.[22] The State regulates electricity prices in the non-price zones because electricity supply is totally isolated from UES in those areas.

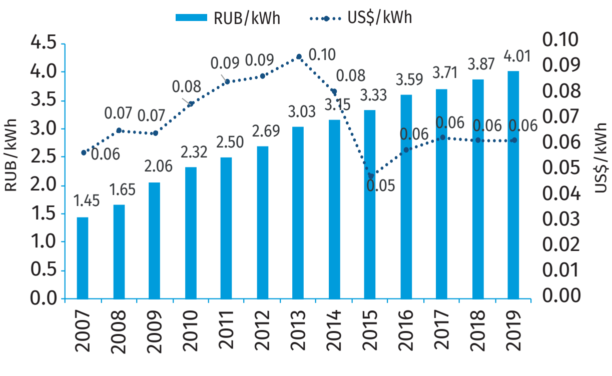
Figure 3. **Electricity Market Price Zones in the Russian Federation**

Source: Association NP Market Council (2020)[23]

The responsibility for setting regulated tariffs for electricity and capacity supplied to the residential consumers as well as tariffs for the electricity supply in the non-price zones lies with the Federal Anti-Monopoly Service (FAS).[24] FAS also regulates the tariffs for renewable energy, e.g., in the case of electric power purchased for compensating the grid losses.

The average electricity tariff for the end consumer in the retail market steadily increased over the past years. Average tariffs for the period 2007–2019 are displayed in Figure 4.

Figure 4. **Average Electricity Tariff for Residential Consumers in Russia in 2007–2019 (USD/kWh)**



Source: Russian Federation Federal State Statistics Service[25]

Note: The decrease in USD/kWh tariffs between 2013 and 2015 reflects fluctuations in the USD/RUB exchange rate.

SMALL HYDROPOWER SECTOR OVERVIEW

The current regulatory definition of small hydropower (SHP) in Russia is hydropower plants with an installed capacity of up to 30 MW with a turbine wheel diameter of up to 3 metres.[22,26] The current chapter primarily considers data on SHP plants with an installed capacity up to 10 MW, but information on SHP up to 30 MW is also referenced. Additionally, it must be noted that strategic planning documents and state support schemes in Russia classify hydropower plants into two major groups: up to 25 MW and over 25 MW.[8,21] However, the 25 MW threshold is not the regulatory SHP definition, but rather a definition used for strategic planning purposes and promotion of renewable energy.

As of 2021, the installed capacity of SHP up to 10 MW was 168.4 MW and of SHP up to 30 MW it was 852.9 MW. The technically feasible potential for SHP up to 30 MW is estimated to be 825,844.6 MW, indicating that only approximately 0.1 per cent has been developed.[27,28,29,30,31,32,33]

The number of SHP plants operating in Russia published in Russian sources varies from 60–70 to 200–300, with the higher values found in the earlier reports. To clarify this discrepancy, an array of information about SHP plants in Russia was summarized in the *World Small Hydropower Development Report (WSHPDR) 2019*, concluding that the actual number of operational SHP plants with installed capacity below 10 MW was just over a hundred.[34] For the current edition, the overview of SHP plants has been updated using data utilized in the *WSHPDR 2019* and various recent publications (Table 1). Most of the currently operating SHP plants are located in the Republic of Karelia and the North Caucasus region. The total number of operating SHP plants with installed capacity up to 30 MW has decreased from 141 (*WSHPDR 2019*) to 118 due to the identification of SHP plants taken out of operation.

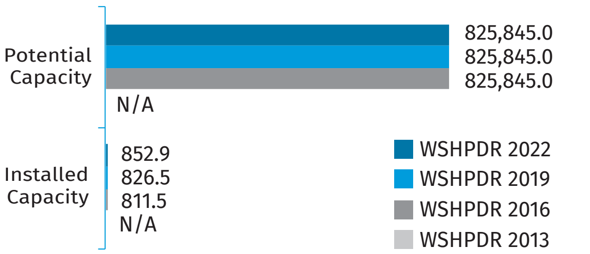
Table 1. **Installed and Potential Small Hydropower Capacity in Russia by Region**

	Federal District	Estimated potential capacity for SHP <30 MW (MW)			SHP <10 MW			SHP 10–30 MW			Total SHP <30 MW		
		Theoretically available	*Technically feasible*	*Economically feasible*	*No. of SHP plants*	*Total installed capacity (MW)*	*% Technically feasible capacity <30 MW*	*No. of SHP plants*	*Total installed capacity (MW)*	*% Technically feasible capacity <30 MW*	*No. of SHP plants*	*Total installed capacity (MW)*	*% Technically feasible capacity <30 MW*
1	North-Western	121,222.2	33,377.8	19,755.6	18	27.9	0.1	11	267.3	0.8	29	295.2	0.9
2	Central	18,688.9	6,466.7	3,488.9	19	30.1	0.5	2	57.8	0.9	21	87.9	1.4
3	Southern	100,444.4	30,666.7	17,111.1	5	11.6	0	1	21.6	0.1	6	33.2	0.1
4	North Caucasus	35,111.1	10,666.7	5,555.6	24	70.2	0.7	11	215.1	2	35	285.2	2.7
5	Volga	300,000.0	93,555.6	51,400.0	10	6.6	0	4	79.6	0.1	14	86.2	0.1
6	Ural	77,777.8	25,333.3	14,000.0	2	9.4	0	0	0	0	2	9.4	0
7	Siberian	966,800.0	301,777.8	166,222.2	5	7.1	0	0	0	0	5	7.1	0
8	Far Eastern	1,003,777.8	324,000.0	178,000.0	4	5.6	0	2	43.2	0	6	48.8	0
	Total	**2,623,822.2**	**825,844.6**	**455,533.4**	**87**	**168.5**	**0.0**	**31**	**684.6**	**0.1**	**118**	**853.0**	**0.1**

Source: Nefedova, L.,[27] Kiselyova, S.,[28] MSU and JIHT,[29] Hydropower Museum,[30] MNTO INSET,[31] RusHydro,[32] Nord Hydro,[33] *WSHPDR 2019*[34]

Changes in SHP installed and potential capacity relative to the *WSHPDR 2019* are displayed in Figure 5. A decrease in SHP capacity of up to 10 MW is partially accounted for by the decommissioning and temporary suspension of operations in a number of plants (Figure 6). Conversely, the overall increase in SHP installed capacity up to 30 MW is a result of the commissioning of additional SHP plants above 10 MW in capacity, as SHP plants with capacity between 10 MW and 30 MW are preferred for economic reasons. The figures cited in the current chapter also reflect more accurate data becoming available.

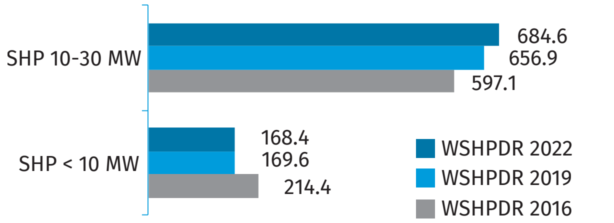
Figure 5. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Russia (MW)**



Source: Nefedova, L.,[27] Kiselyova, S.,[28] MSU & JIHT,[29] Hydropower Museum,[30] MNTO INSET,[31] RusHydro,[32] Nord Hydro,[33] *WSHPDR 2019*,[34] *WSHPDR 2013*,[35] *WSHPDR 2016*[36]

Note: Data for SHP up to 30 MW.

Figure 6. **Small Hydropower Installed Capacities in the WSHPDR 2016/2019/2022 in Russia (MW)**



Source: Nefedova, L.,[27] Kiselyova, S.,[28] MSU & JIHT,[29] Hydropower Museum,[30] MNTO INSET,[31] RusHydro,[32] Nord Hydro,[33] *WSHPDR 2019*,[34] *WSHPDR 2016*[36]

In the Russian Federation, small rivers are defined as rivers less than 100 kilometres-long with a watershed area less than 2,000 km^2 and located within a single geographical zone.[37] Small rivers are prevalent in the hydrographic network of Russia: the share of small rivers shorter than 100 kilometres in the total length of the hydrographical network is 95 per cent, while their total flow constitutes an average of approximately 50 per cent of the total flow of all rivers in Russia.[38] The technically feasible generation potential of the small rivers in Russia is estimated at approximately 372 GWh per year.[39]

SHP plants in Russia have a long history. The first hydropower plant in the country, with an installed capacity of 0.18 MW, was constructed in the Altai region in 1882 for powering water pumps at the Zyryanovsky mine. Another unique example, the Porogy SHP plant of 1.45 MW, was constructed in the Chelyabinsk region in 1910 and remained operational until 2017.[40] Numerous SHP plants were constructed in the 1930s, but many were destroyed during the Second World

War. The SHP energy sector experienced a quick revival in the post-war years, with over 6,600 SHP plants in operation at the time.[41] Later, the Soviet energy policy was changed in favour of large hydropower plants. Thereafter, production of SHP equipment was closed and most SHP plants were taken out of operation and consequently abandoned. Recent surveys suggest that restoration of some of these SHP plants can be economically feasible.[42] The SHP sector in Russia is currently in a stage of revival and many plants have been built or refurbished in recent years. A partial list of recently commissioned and refurbished SHP plants is provided in Table 2.

Table 2. **List of Selected Operational Small Hydropower Plants in Russia**

Name	*Location*	*Capacity (MW)*	*Head*	*Plant type*	*Operator*	*Launch year*
Verhnebalkarskaya	Cherek Balkarskiy	10.00	125.0	Run-of-river	AO RusHydro	2020
Ust-Dzhegutinskaya	Kuban River	5.60	31.0	Reservoir	AO RusHydro	2020
Barsuchkovskaya	Barsuchkovskiy discharge canal	5.25	12.7	Reservoir	PAO RusHydro	2020
Maikopskaya Malaya GES	Belaya	0.40	N/A	Reservoir	OAO Adygenergostroy	1999/2020
Malaya Krasnopolyanskaya	Beshenka	1.50	230.0	Run-of-river	OOO Lukoil-ecoenergo	1947/2005/2020
SHP on Toolailyg river	Mouth of Barlyk river	0.05	N/A	Run-of-river	? (Community SHP)	2019
Bol'shoi Zelenchuk	Bolshoi Zelenchuk	1.26	9.0	Reservoir	AO RusHydro	2018
Uchkulanskaya	Uchkulan river	1.00	N/A	Run-of-river	ZAO Foton	1937/1987/2018
Enashiminskaya	Enashimo	5.00	59.5	Run-of-river	OOO Enashimskaya GES (AO Yuzhuralzoloto grupps companiy)	1961/2016
Kokadoiskaya	Argun river	1.30	N/A	Reservoir	GUP Chechenskaya Generiruyushchaya Kompaniya	2015
Lykovskaya	Zusha river	0.76	N/A	Reservoir	OOO Lykovskaya GES	1953/2015
Kalliokoski	Tohmajoki river	0.98	9.3	Reservoir	AO Nord Hydro	2014
Tomskaya	Cleaned wastewater discharge duct	1.00	N/A	Run-of-river	OOO Tomskaya generiruyuschaya kompanya	2014
Novokarachayevskaya	Kuban' river	1.26	N/A	Reservoir	ZAO Foton	2013
Ryymakoski	Tohmajoki river	0.63	9.2	Reservoir	AO Nord Hydro	1937/2013
Ulyanovskaya MGES-2	Ulyanovskiy purified wastewater discharge duct	0.32	35.0	Run-of-river	MUP Ulyanovskvodokanal	2011
Mukholskaya	Cherek Balkarskiy	0.90	28.5	Reservoir	AO RusHydro	1962/2011
Tokmovskaya	Moksha river	0.32	6.0	Reservoir	FBGU Mordovmeliovodkhoz	2010
Eshkakonskaya	Eshkakon	0.60	N/A	Reservoir	OOO Nizhegorodskiy Institute of Applied Technologies	2009
Fasnal'skaya	Songutidon	6.40	127.0	Run-of-river	OAO Turboholod	2009

Source: Nefedova, L.,[27] Kiselyova, S.,[28] MSU & JIHT,[29] Hydropower Museum,[30] MNTO INSET,[31] RusHydro,[32] Nord Hydro,[33] NP Soviet Rynka,[43] Tsukanov, V.I.[44]

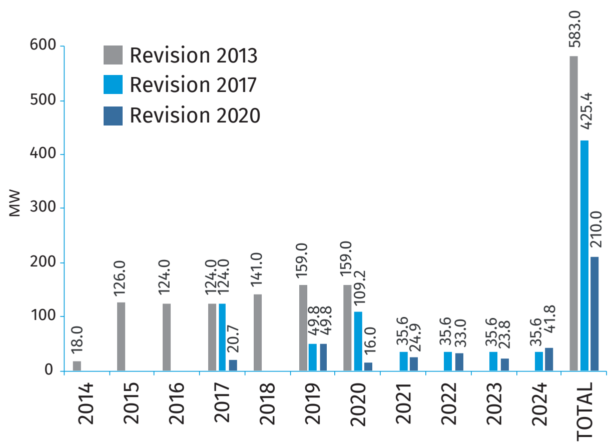
Russia possesses a variety of SHP technologies and produces equipment for SHP plants.[45,46,47,48] Two major SHP developers in the country are RusHydro and Nord Hydro. RusHydro's development programme for 2020–2026 includes the construction of a number of new SHP plants and the complete renovation of several existing ones, particularly in the North Caucasus and Southern regions.[49] Its targets also include the implementation of advanced technologies in SHP development, such as the use of new construction materials, the utilization of advanced electro-mechanical equipment for the remote monitoring of plant performance, the use of prefabricated container-type power generation units with an installed capacity below 5 MW, the installation of SHP plants of below 5 MW capacity on existing technological hydro-engineering systems and hybrid design of small power plants combining SHP with solar and/or wind generation facilities, among others.

Nord Hydro is currently planning the reconstruction of 37 SHP plants and the construction of 10 new SHP plants on company property. Furthermore, their strategic plan for the period up to 2025 includes the construction of SHP plants in 21 regions of Russia.[50] Nord Hydro is supported by the Russian Direct Investment Fund (RDIF) in developing SHP plants in the Republic of Karelia.[51,52] RDIF co-invested jointly with the Eurasian Development Bank (EDB) and the International Investment Bank (IIB) in the development of the Beloporozhskaya-1 and

Beloporozhskaya-2 SHP plants, with an installed capacity of 24.9 MW each.[53]

Russian Federation Government Resolution No. 861-r from 28 May 2013 established installed capacity targets for SHP development in 2013–2020.[54] These targets were later revised towards a noticeable reduction of the total planned capacity, while their implementation was extended to 2024 (Figure 7).[55,56] However, these SHP development targets had not been met as of 2021.

Figure 7. **Targets for Development of Small Hydropower in the Russian Federation in 2014–2024 (MW)**



Source: Government of the Russian Federation[54,55]

Note: The comparison is between the 2013, 2017 and 2020 revisions of the legislation on SHP targets; targets use the up to 25 MW definition of SHP.

The current state and corporate development plans and programmes in the Russian Federation include the construction and major renovation of approximately 40 SHP plants in 2020–2026. Examples of several ongoing projects are provided in Table 3.

Table 3. **List of Selected Ongoing Small Hydropower Projects in the Russian Federation**

Name	*Location*	*Capacity (MW)*	*Head*	*Plant type*	*Developer*	*Planned launch year*	*Development stage*
Dzaudzhikausskaya	Terek river	8.2	27	Run-of-river	PAO RusHydro	2025	Reconstruction
Sengileyevskaya	Nevinnomysskiy canal	18	45.5	Reservoir	PAO RusHydro	2025	Reconstruction
Psygansu	Psygansu river	3.7/19.1	284	Run-of-river	PAO RusHydro	2024	Design stage
Kubanskaya GAES	Bolshoy Stavropolskiy canal	19.4	24	Reservoir	PAO RusHydro	2025	Reconstruction
Gizeldonskaya	Gizeldon river	26.4	289	Run-of-river	PAO RusHydro	2025	Reconstruction

Source: Ministry of Energy,[21] RusHydro,[49] Nord Hydro[50]

There are thousands of potential SHP sites in Russia, therefore, it is practically impossible to list them all, given the scale of the country. Table 4 provides several examples of potential SHP sites. An extended list of selected potential SHP sites in Russia, as well as SHP projects under way in the country, is made available in the Global SHP database.

Table 4. **List of selected Potential Small Hydropower sites in the Russian Federation**

Name	*Location*	*Potential capacity (MW)*	*Head*	*Type of site*
Dargavskaya	Gizeldon River	2.8	130.0	New
Donguz-Orunkel	Baksan River	3.5	436.0	New
Yaglanporozhskaya	Chirka-Kem River	13.6	17.4	New
Kurminskaya	Karakoisu River	15.0	32.2	New
Zheleznoporogskaya	Chirka-Kem River	16.0	16.5	New

Source: Tsukanov, V.I.,[44] Government of the Republic of Karelia,[57] Government of the Republic of Chechnya,[58] Cleandex,[59] AO SO EES ODU Yuga[60] Kuvalkin et al.[61]

RENEWABLE ENERGY POLICY

The Government of the Russian Federation has recognized climate change as a major problem, ratifying the Paris Agreement in 2019, and has introduced plans for minimizing the climate change impacts.[62]

Renewable energy policy in Russia is set by the Government and considers accelerated development of renewable energy sources (RES) as an important factor of the economic modernization of the country.[56] The main focus of RES development in Russia are wind and solar power, with a comparatively minor role allocated to SHP.

The use of RES, including SHP, is considered in Russia as part of the broader concept of energy efficiency. In 2020, the Government approved an updated federal policy for increasing energy efficiency in the electric power industry through RES for the period up to 2035. The policy has set a target of 4.5 per cent for the share of RES in the total electric power generation by 2024.[56] This target is established for the State, but is not legally binding for electric power producers and no fines are imposed for failing to meet this target or other similar targets.

An intensive utilization of RES in Russia would provide several important benefits, including:

- Electric power supply for isolated consumers, i.e., those who do not have access to the centralized electric power distribution grids;
- Reduction of liquid fuel shipments to remote northern areas of Russia, including the Arctic region (e.g., replacing local diesel generation with RES);
- Increased reliability of the electric power supply in areas with centralized electric power distribution grids, particularly those experiencing electricity shortages;
- Reduction of air pollution caused by thermal power plants fuelled by coal or oil.

The Russian Federation joined the International Agency for Renewable Energy (IRENA) on 22 July 2015.[63] This membership allows Russia to participate in the development of international renewable energy standards and adopt best practices and advanced technologies.

SHP development and operation in Russia are regulated by the Federal Laws covering any hydropower plants, including federal laws “On the Electrical Power Energy Industry”, “On Technical Regulation” and “On the Safety of the Fuel-Energy Complex Facilities”, as well as by the laws and regulations regarding other RE, including the federal law “On Energy Conservation, Energy Efficiency, and Changes in Several Legislative Acts of the Russian Federation”.[20,64,65,66]

The Parliament of the Russian Federation approved amendments to the Federal Law on the Electrical Power Energy Industry in 2011, which created new opportunities to use the capacity market mechanism to encourage RES growth on the wholesale market and imposed priority energy purchase on the retail market by grid companies in volumes necessary to compensate for energy losses.[20] This approach was further developed in 2013, when the Government introduced a new capacity-based scheme for supporting renewable energy facilities, including SHP plants.[67,68] This scheme provides for the financial viability of RES investment projects by concluding an agreement for the sale/purchase (supply) of capacity between RES developers and wholesale market consumers. It ensures the purchase of installed capacity of approved renewable energy installations at a regulated price for 15 years.

RES investment projects are selected for the capacity-based scheme annually on a competitive basis within the limit of total RES installed capacity approved by the authorities each year. To officially quality as an RES facility under the scheme, an investment project must comply with various qualifying criteria, including:

- The project is developed in one of the price zones of the wholesale market (i.e., projects in the non-price zones do not qualify for the scheme);
- The project’s installed capacity is equal to or exceeding 5 MW but less than 25 MW;
- The project does not exceed the maximum cost established by the Government for this project;
- The project is commissioned within the agreed deadline, etc.

Recognition of a completed RES project as a qualified generating facility is carried out by the Market Council upon the owner’s application.[68] The prices of installed capacity supplied by the qualified facilities under the agreement for the sale/purchase (supply) of capacity are determined by the commercial operator of the wholesale market for each generating facility specified in such agreements according to the methodology set by the Government. The feed-in tariffs (FITs) for electricity supplied to the wholesale market are calculated individually for each qualified facility based on the total investment project cost approved in the agreement. This approach ensures the return of investments into the qualified facilities over 15 years.[67]

The capacity-based approach differs from the support mechanisms in other countries, where RES are promoted based on the purchase of the electricity output (MWh) at a guaranteed FIT. The electricity output-based approach proved to be impractical in Russia due to existing regulatory and technical obstacles.

Amendments to the Federal Law “On Electrical Power Energy Industry” focused on micro-generation took effect in 2019. The amended law formalized the definition and criteria of a micro-generation facility based on RES and created a legal foundation for the development of this sector. It allows the sale of excess electricity produced through micro-generation and thus reduces the payoff period of micro-generation facilities, making them more appealing to investors. Additionally, relevant amendments made to the Tax Code suspended taxes on the revenue of individuals selling electric power until 2029.[20,69]

While there is no legislation specifically targeting or promoting SHP development, SHP projects in Russia must comply with a range of National Standards applicable to all hydropower plants regarding their development and safety. There are two National Standards, GOST R-51238-98 and GOST R-56125-2014, specifically pertaining to SHP plants, regulating some technical aspects of SHP development and applicable terminology.[22,26,70]

SHP plants with an installed capacity of below 25 MW that participate in the retail electric power market can also benefit from:

- Subsidies of the grid connection costs;
- Obligation of the grid companies to compensate for electricity losses on their network by priority purchases of electricity produced from RES;
- FITs that ensure a certain return on the investment (currently at 14 per cent);
- Obligation of grid companies to buy renewable energy despite the difference in tariffs (renewable energy tariffs are now 3.5 times higher than those for conventional energy generators).

COST OF SMALL HYDRPOWER DEVELOPMENT

SHP project costs in Russia vary depending on the design, equipment prices and construction costs. A few examples of SHP project costs are provided in Table 5.

Table 5. **Costs of Small Hydropower Projects in Russia**

Name	*Location*	*Capacity (MW)*	*Head*	*Development stage as of 1 January 2021*	*Developer*	*Estimated cost per kW in RUB (USD)*
Segozyorskaya	Segezha River	8.1	N/A	Design	En+ group	176,000 (3,000)
Beloporozhskaya -1	Kem River	24.9	13.1	Operating since 2020	AO Nord Hydro	174,000 (2,600)
Beloporozhskaya -2	Kem River	24.9	13.1	Construction completed	AO Nord Hydro	174,000 (2,600)
Bolshoi Zelenchuk	Bolshoi Zelenchuk River	9.0	9.0	Operating since 2018	PAO RusHydro	165,000 (2,800)
Krasnogorskaya -1	Kuban River	24.9	24.9	Construction started in 2019	PAO RusHydro	164,000 (2,600)
Barsuchkovskaya	Bolshoy Stavropol Canal	5.3	12.7	Operating since 2020	PAO RusHydro	155,000 (2,400)

Source: RusHydro,[49,71,72,73] Nord Hydro,[50] RDIF,[51,52] EDB[53]

The average cost of SHP projects qualified for state support in 2021–2024 as an RES is estimated at 193,465 RUB/kW (2,600.22 USD/kW), while being limited to a maximum of 194,640 RUB/kW (2,616.01 USD/kW).[74] The average cost of a project includes both capital expenditures and the average annual cost of operation. For the period up to 2024, there is a regulatory limit of 146,000 RUB/kW (1,962.28 USD/kW) on capital expenditures for construction of SHP plants officially qualified to operate in the retail markets as RES.[56]

The structure of SHP project costs varies, but the biggest share is usually represented by the project construction cost (including equipment and materials). For example, of the total funds spent on the Beloporozhskaya-1 SHP plant, 5 per cent was allocated for the design, 72 per cent for the construction, 4 per cent for other investment costs including land allocation, grid connection, etc. and the rest went towards various bank loan expenses.[75]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The main guarantee for RES investors is provided under the Federal Energy Efficiency Law regarding the determination of the special tariffs for energy efficiency investments, including RES projects.[66] Entities investing in energy efficiency improvements can keep the financial benefits resulting from these investments for a period of at least five years following the regulatory period during which these investments were implemented.

The federal law "On Electric Power Energy Industry" provides several mechanisms for supporting the development of RES in Russia.[20] By signing an agreement for the sale/purchase (supply) of capacity, investors commit to constructing a specific type of a generating facility, of a specific capacity and at a specific location. They also guarantee the availability of the respective installed capacity for electricity production. In return, investors are remunerated at regulated tariffs. Special state auctions are held each year selecting RES investment projects (wind power, solar power and SHP) under this scheme. As a result of eight competitive selections of investment projects for the construction of RES generating facilities, which took place from 2013 to 2020, only 11 applications for the construction of SHP plants were selected, with a total capacity of 168.07 MW.

There is a variety of possibilities for accessing financial support for SHP projects. Generally speaking, responsibility for developing SHP in Russia is divided between regional and municipal authorities and private investors. Regional authorities interested in the development of SHP are capable of financing studies of hydropower potential in the region, but further implementation usually depends on private investors.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Changes in river flows are the most important climate change factor for hydropower. Changes in the global hydrological cycle have already taken place and will become more apparent in the next few decades.

Researchers from the Laboratory of Global Energy Problems of the MEI National Research University, supported by the Russian Fund for Fundamental Research, calculated changes in the climatic characteristics determining renewable energy potential, including the volume of river runoff. These studies have shown that the observed and expected climate change across most of the territory of the Russian Federation is likely to be beneficial to the main RES, including renewable hydropower.[76] However, heavier precipitation can lead to the failure of hydropower generating units, increased sedimentation in the reservoirs (consequently reducing the useful life of hydropower plants) and increased risk of dam erosion and catastrophic floods.

The average increase in the hydropower output in Russia is projected at 3–4 per cent by the middle of the 21st century, in comparison with the beginning of the century. However, this trend would not be observed in the southern mountainous areas of Russia. Climate change is expected to cause an initial increase in the water resources in this region due to melting mountain glaciers, followed by a reduction of water resources available for hydropower production.[77]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barrier to the development of RES projects in Russia, including SHP, is the availability of vast fossil fuel resources and the importance of the gas, oil, coal and nuclear industries to the country's economy. Other significant barriers in developing SHP projects in Russia include:

- Lack of state-supported programmes for SHP development;
- Insufficient quotas for SHP projects included in the mechanisms stimulating RES development after 2024;
- Excessive regulatory requirements for SHP projects (e.g., mostly the same as for large hydropower plants);
- Lengthy procedures for land allocation and approval for projects, which can sometime last many years;
- Excessive requirements for the provision of grid connection in the case of projects implemented by regional grid companies;
- Shortage of up-to-date scientific data on the regional SHP development potential;
- Lack of standard technical and methodological regulations, information technologies and software required for designing, constructing and operating RES generation plants;
- Lack of specialist training and skilled professionals at the regional level;
- Insufficient state support for the development of SHP technologies;
- Natural and environmental constraints, including seasonal factors (in particular, frosts and floods), locations in environmentally sensitive areas and others.

Russian investors are reluctant to finance SHP projects due to the long-term period of recoupment for such investments. Consequently, there are many cases where ongoing construction of SHP plants has been put on hold.

At the same time, several policies supporting SHP development exist in Russia, including the following:

- State support for electric power plants with installed capacity of between 5 MW and 25 MW that officially qualify as RES, including SHP plants. This threshold is expected to increase to 50 MW in order to expand financial support to a wider range of RES projects;
- A support scheme for the sale of renewable energy generating capacities to the wholesale and retail markets at the prices and in accordance with the level defined by the Government. The main purpose of such support schemes is to create economic incentives for developing the production of main and auxiliary generating equipment used in the production of electric energy using RES;
- Compensation at the regional level for transmission grid operators for power losses in their grids equal to the amount of electricity generated by the connected RES facilities;

More generally, enabling factors for SHP development in Russia also include the following:

- Only a small fraction of the potential SHP capacity of the country is actively utilized at the present, with potential locations including an abundance of formerly operational SHP sites and non-powered hydraulic infrastructure;
- Extensive historical experience with SHP development and existing technical capacity and expertise in this sector on the national level, including established technical standards;

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Slovakia

International Center on Small Hydropower (ICSHP)

KEY FACTS

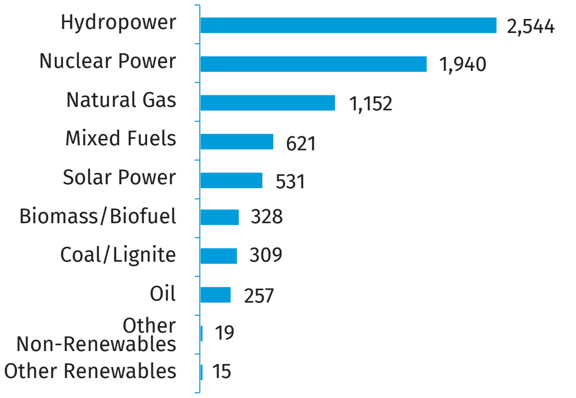
Population	5,458,827 (2020)[1]
Area	49,035 km^2 [2]
Topography	The terrain of Slovakia is predominately mountainous with some lowlands in the south. The Carpathian Mountains occupy the majority of the country, sweeping from east to west. The highest elevations are found in the High Tatra and Low Tatra subranges in the central region. The highest point, Gerlachovský Peak, at 2,655 metres, is located in the High Tatra Mountains close to the border of Poland. Along the southern border with Hungary are the Little Atfold lowlands in the south-west and the Eastern Slovakian Lowland in the south-east, which make up part of the Inner Carpathian Depressions.[2]
Climate	Slovakia has a moderate continental climate, with some variations between regions. The northern, mountainous region is colder with snow remaining on the summits of the highest peaks into the summer. In the southern regions where most of the population resides, there are four distinct seasons. The average temperature in July is approximately 20 °C and in January temperatures can reach close to –5 °C.[2]
Climate Change	Over the last century, average air temperatures in Slovakia have increased significantly, by 2 °C along with some less significant increases in precipitation. By 2100, average temperatures are expected to increase by an additional 1.5–4.7 °C throughout the whole country. Average precipitation is expected to increase in the northern regions, especially in the winters and decrease in the southern regions, especially in the summers.[3]
Rain Pattern	Annual rainfall varies between regions. The northern regions experience the most precipitation, with an average of 1,100 mm per year with some places surpassing 2,000 mm per year. In the southern regions, annual precipitation is approximately 570 mm. Precipitation is experienced throughout the year with a slight increase during the summer months and a slight decrease during the winter months. During winters, precipitation is usually in the form of snow.[2]
Hydrology	The rugged terrain of Slovakia is home of many rivers and mountain lakes. Many of the rivers flow southwards into the Danube, the country's most important river. The river separates into other channels as it flows south-westwards while its main channel continues on to form the border with Hungary. The Little Danube, one of the channels, branches east and then south-east to meet the Váh and Nitra Rivers. Other major rivers that flow into the Danube and its channels are Hron and Ipel. Many of the main rivers in the eastern region of the country, such as the Hornád, the Bodrog and the Torysa, flow southwards into Hungary. The Poprad, also in the east, is the only sizable river that flows northwards, into Poland. River flows tend to be strongest during early spring and lowest at the end of summer.[2]

ELECTRICITY SECTOR OVERVIEW

In 2020, the total installed capacity in Slovakia was 7,716 MW, of which over 44 per cent was with renewable energy sources. Hydropower accounted for 2,544 MW (33 per cent), nuclear power for 1,940 MW (25 per cent), natural gas for 1,152 MW (15 per cent), mixed fuels for 621 MW (8 per cent), solar power for 531 MW (7 per cent), biomass/biofuel for 328 MW (4 per cent), coal/lignite for 309 MW (4 per cent), oil for 257 MW (3 per cent) and the remaining 1 per cent was split between other non-renewable sources for 19 MW and other renewable sources for 15 MW (Figure 1).[4] Total installed capacity has been gradually decreasing in the past decade, due to the elimination of much of the coal and lignite capacities. In 2019, the Government announced that coal and lignite would be completely phased out by 2023.[5] To compensate for the closures, the nuclear plant at Mochovce is currently undergoing expansion.[6]

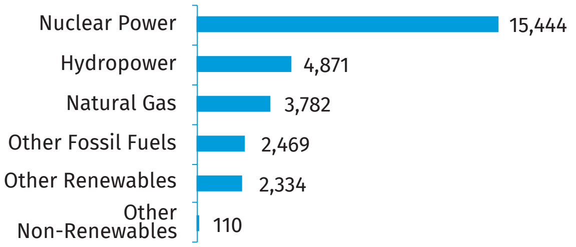
In 2020, the total electricity generation in Slovakia was 29,010 GWh, of which, 25 per cent was with renewable energy sources. Nuclear power generated the majority, at 15,444 GWh (53 per cent), hydropower 4,871 GWh (17 per cent), natural gas generated approximately 3,782 GWh (13 per cent), other fossil fuels, including coal, oil and mixed fuels, 2,469 GWh (9 per cent), other renewable sources, including solar power, biomass and wind power, 2,334 GWh (8 per cent) and other non-renewable sources 110 GWh (0.3 per cent) (Figure 2). Slovakia has been a net importer of electricity since 2007 and in 2020, net imports were 318 GWh, much lower than previous years.[7] Total imports amounted to 13,288 GWh, mostly from the Czech Republic and Poland, and total exports amounted to 12,970 GWh, mostly to Hungary and Ukraine. Total domestic electricity consumption was 29,328 GWh.[4] The electrification rate of Slovakia is 100 per cent.

Figure 1. **Installed Electricity Capacity by Source in Slovakia in 2020 (MW)**



Source: SEPS[4]

Figure 2. **Annual Electricity Generation by Source in Slovakia in 2020 (GWh)**



Source: SEPS[7]

The electricity sector in Slovakia began restructuring in 2000 and completed its liberalization process in 2006, when Italian company, Enel closed its purchase of 66 per cent of the previously state-owned electricity supplier, Slovenské elektrárne (SE) with the remaining shares kept by the state.[6] Since then, other private companies have been able to produce and sell electricity, however, SE still represents the largest market shares. In 2020, SE owned and operated over 53 per cent of the country's installed capacity and generated over 65 per cent of the total electricity.[8]

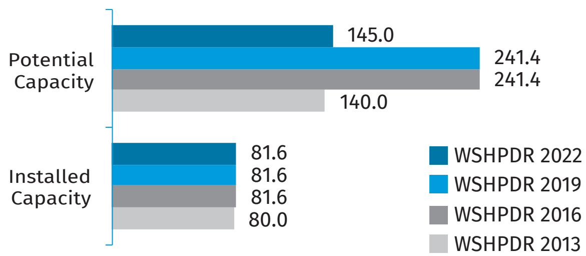
There are three regional Distribution System Operators (DSO) that are 51 per cent state-owned — Západoslovenská energetika, a.s. (Western Slovak Power Utility), Stredoslovenská energetika, a.s. (Central Slovak Power Utility) and Východoslovenská energetika, a.s. (Eastern Slovak Power Utility). The entire transmission network is operated by state-owned Slovenská elektrizačná prenosová sústava (SEPS). The country's power system is integrated into the European Network of Transmission System Operators (ENTSO-E). Transmission lines cross national borders with the Czech Republic, Hungary and Poland, which facilitates trade between the countries. In 2019, an agreement was made between SEPS, Západoslovenská energetika and Hungarian distribution company, E.ON Észak-dunántúli Áramhálózati, to begin the Danube InGrid project that will create a smart grid between the two countries with an aim to appropriately balance the increase of renewable energy sources with energy consumption.[5]

Electricity prices for the final consumer include a network fee, a value-added tax (VAT) and the supplier price. The Regulatory Office for Network Industries (RONI) is the sector's regulatory body and determines the network fees.[8] In 2020, the average price of electricity for medium-sized households was 0.1686 EUR/kWh (0.18 USD/kWh), which was approximately 20 per cent lower than the European Union (EU) average. The average price for non-household consumers was 0.0977 EUR/kWh (0.10 USD/kWh), which was slightly above the EU average.[9]

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) is defined in Slovakia as plants with a capacity of 10 MW or less. Total SHP installed capacity is 81.6 MW according to the most recent accurate data available.[10] Potential capacity is 145 MW based on planned SHP development, indicating that approximately 56 per cent of the total potential has been developed.[11] Compared to the data from the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity has remained the same while potential capacity has decreased due to an updated plan by the Government to develop a total of 145 MW rather than the previously planned 241.4 MW (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Slovakia (MW)**



Sources: Energie 21,[10] *WSHPDR 2019*,[12] *WSHPDR 2016*,[13] *WSHPDR 2013*[14]

Slovakia has a long history of SHP, beginning in the late 19th century. Many of the earlier plants were originally purposed to power individual industrial plants and factories wherein some simply used the hydraulic energy produced with water wheels while some also produced electricity. Eventually, many of the plants were connected to the grid to provide electricity to the population by the state-owned SE.[15] There are now 217 SHP plants throughout the country ranging from less than 100 kW to 10 MW (Table 1).[10] Since the privatization of the sector, the majority of today's SHP plants are operated by small, private companies with the exception of a few owned by SE (Table 2).[8]

Table 1. **Small Hydropower in Slovakia**

Capacity	*Number of plants*	*Installed capacity [MW]*	*Generation [GWh/year]*
< 0.1 MW	118	4.586	19.56
0.1 MW to 1 MW	78	32.34	124.06
1 MW to 10 MW	21	44.71	138.18
Total	**217**	**81.636**	**281.8**

Source: Energie 21[10]

Table 2. **List of Selected Existing Small Hydropower Plants in Slovakia**

Name	*Installed capacity (MW)*	*Operator*	*Launch year*
Dobšiná III	0.32	SE	2014
Dobšiná II	2.0	SE	1994
Veľké Kozmálovce	5.32	SE	1988
Čierny Váh flow	0.76	SE	1982
Tvrdošín	6.10	SE	1979
Bešeňová	4.64	SE	1976
Ružín II	1.80	SE	1974
Krompachy	0.33	SE	1932
Švedlár	0.09	SE	1924
Rakovec	0.50	SE	1913

Source: SE[8]

In 2011, the Government published the Plan for Hydroenergy Power Utilization in Slovakia, which planned for the new construction of up to 368 SHP plants totalling 160 MW by 2030, bringing the total installed capacity of SHP to 241 MW.[12] However, pressure to maintain the ecological sustainability of rivers has caused many rivers to gain protection status as well as the enforcement of environmental impact assessments (EIA) to be carried out. In recent years, this has led to the delay or cancellation of some projects. In some cases, such as the planned Hronský Beňadik project, the country's Supreme Court had to put a stop to construction after learning that investors did not properly undergo an EIA. Local non-governmental organizations (NGOs) have also got involved, pushing to cancel all projected planned on the Hron River.[16] The more recent, Integrated National Energy and Climate Plan 2021–2030 published in 2019 still foresees further SHP development, but at levels lower than the 2011 plan. This plan expects that the total installed capacity of all types of hydropower will amount to 2,671 MW by 2030, in which 145 MW of it would be SHP.[11]

RENEWABLE ENERGY POLICY

The objectives of the 2014 Energy Policy of Slovakia are to ensure an affordable, environmentally sensitive and reliable supply of electricity for all consumers. This plan envisaged a 24 per cent renewable energy share in electricity generation by 2020 and 27 per cent by 2030.[17] In 2020, the actual share of renewable energy electricity generation was 25 per cent, slightly surpassing the first milestone. The more recent Integrated National Energy and Climate Plan published in 2019 focuses on the aim for a low-carbon circular economy by 2050. Renewable energy objectives include the 27 per cent in electricity generation as in the previous plan and a 19.2 per cent share in final consumption by 2030. More specifically, this plan outlines individual targets of installed capacity and generation of each renewable energy source. By 2030, the proposed respective capacity and generation of hydropower are 2,671 MW and 5,322 GWh; of solar power are 1,200 MW and 1,260 GWh, which will be focused to provide decentralized power to homes and buildings; of wind power are 500 MW and 1,000 GWh and of biomass/biofuel are 400 MW and 2,540 GWh. There will also be an inclusion of 4 MW and 30 GWh of geothermal energy, which is set to first appear in 2024.[11]

To promote renewable energy on the grid, renewable energy sources have priority connection to the electricity system, are eligible for feed-in tariffs (FITs) and can get investment support during construction. A 2020 amendment to the 2018 Renewable Energy Act stipulates that FITs are to be available for solar power installations above 100 kW and to all other renewable energy installations above 500 kW. It also introduces green auctions that can be available for new solar power installations between 100 kW and 2 MW and all other renewable energy installations between 500 kW and 10 MW.[18]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers to SHP development in Slovakia include:

- Other renewable energy sources, such as biomass, biogas and solar photovoltaic, have a shorter payback period than SHP plants;
- Administrative barriers are discouraging to investors due to the construction of hydropower plants in Slovakia having a long legislative process. When private developers identify a suitable location for the plant, the permission procedure to comply with the Slovak Building Act demands zoning planning documentation and additional documentation;

- Environmental regulations require investors to obtain a permission according to the Slovak Water Act and an approval from various environmental organizations. This includes carrying out a comprehensive EIA;
- There is a mistrust towards the construction of SHP plants from the general public and environmental activists.[12,16]

The main enablers for SHP development in Slovakia include:
- Financial incentives such as FITs and green auctions are in place for new installations of hydropower between 500 kW and 10 MW;
- SHP potential in the country has not yet been reached, presenting opportunities for new SHP projects;
- Presence of political will exemplified in national plans that include increasing the country's SHP installed capacity to 145 MW by 2030, proving that new construction is encouraged during these next few years.[11,18]

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Ukraine

Dmytro Stefanyshyn, Institute of Telecommunications and Global Information Space

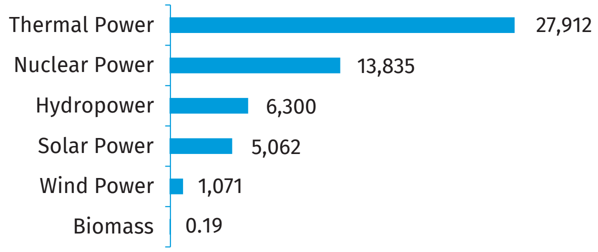
KEY FACTS

Population	44,385,155 (2019)[1]
Area	603,549 km^2 [2]
Topography	Ukraine is a country of plains, with most of its land located below a 300 metre altitude. Mountainous areas such as the Ukrainian Carpathians and the Crimean Mountains occur only on the country's borders and account for less than 5 per cent of its area. The highest point is Mount Hoverla in the Carpathians, at 2,061 metres above sea level.[2]
Climate	Ukraine has a temperate climate influenced by moderately warm, humid air from the Atlantic Ocean. Winters, lasting from November to March, are considerably milder in the west than in the east. On the other hand, during the summer, lasting from May to September, the east often experiences higher temperatures than the west. Average annual temperatures range from 5.5–7 °C in the north to 11–13 °C in the south. The average temperature in January, the coldest month, is approximately -3 °C in the south-west and -8 °C in the Carpathians and north-east. The average temperature in July, the hottest month, is approximately 23 °C in the south-east and south, 18 °C in the north-west and 19 °C in the Carpathians.[2,3]
Climate Change	Among the main effects of climate change in Ukraine are warmer winters and the frequent absence of a seasonal snow cover in much of the country. Extreme weather events such as heatwaves and summer droughts are also becoming more common. The incidence of droughts has nearly doubled in the last 20 years.[4] Rivers in Ukraine are experiencing declining runoff and droughts are expected to become more frequent in the coming years.[5,6]
Rain Pattern	Annual precipitation averages 565 mm.[5] Precipitation is uneven across the country, with two to three times as much precipitation occurring during the warmer season as during the cold season.[2] The average annual precipitation ranges from between 600 and 650 mm in the west and north-west to 300 mm in the south and south-east.[3] The highest annual precipitation occurs in the Carpathians (1,500 mm).[2,3]
Hydrology	Ukraine is subdivided into three major hydrological zones—the plain-covered part, the Ukrainian Carpathians and the Crimean Mountains.[6] Almost all of the country's major rivers flow from north-west to south-east through the plains to empty into the Black Sea and the Sea of Azov.[2] The longest river is the Dnieper, approximately 2,201 km in length, of which 980 km are in Ukraine; the Dnieper drainage basin covers 65 per cent of the country's surface area.[3,2,5] In the plain part of Ukraine, the density of the river network varies significantly: with 0.1–0.2 km/km^2 in the south, 0.25–0.5 km/km^2 in the mixed-forest zone in the north and 0.4–0.8 km/km^2 in the forest-steppe zone. The surface runoff varies from 0.2–0.5 l/s from 1 km^2 in the south, with some rivers drying out in the summer, to 3.0–4.5 l/s from 1 km^2 in the north. In the Ukrainian Carpathians, the density of the river network is 1.0 km/km^2 or more. The surface runoff of the Carpathian rivers varies from 15 to 25 l/s from 1 km^2 and reaches 35 l/s from 1 km^2 in the upper reaches of the Tysa River. In the Crimean Mountains, the density of the river network reaches 0.6–0.7 km/km^2 and surface runoff varies from 26 to 0.37 l/s from 1 km^2. In this region, the hydrological regime is unstable and some rivers dry up.[6] In total, more than 63,000 rivers and streams flow in Ukraine, with 93 per cent of them being less than 10 km in length.[3] There are also 1,103 reservoirs in Ukraine, with a total water volume of approximately 55,500 million m^3, and 50,793 artificial ponds (reservoirs with a capacity not exceeding 1 million m^3) with a total water volume of 3,969.4 million m^3.[5,7]

ELECTRICITY SECTOR OVERVIEW

The total installed capacity of power plants in Ukraine as of November 2020 was 54,365 MW.[8] Of the total, 51 per cent came from thermal power (including combined heat and power) plants and almost 26 per cent from nuclear power plants. Thus, thermal and nuclear power accounted for more than 75 per cent of the country's total installed capacity. The remaining 23 per cent was derived from renewable energy, with both large and small hydropower (SHP) plants and pumped-storage hydropower providing approximately 12 per cent, and other renewable energy sources providing also approximately 12 per cent (Figure 1).[8]

Figure 1. **Installed Electricity Capacity by Source in Ukraine in 2020 (MW)**

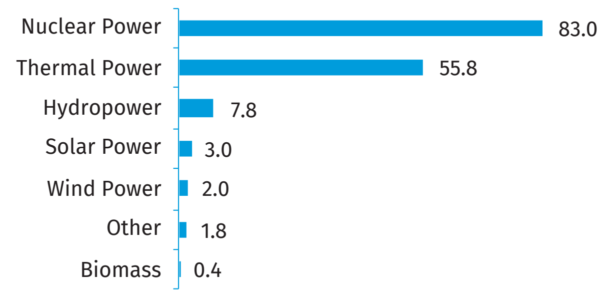


Source: Ukrenergo[8]

Notes: Data are for November 2020 and do not include the fourth hydropower unit with an installed capacity of 324 MW at the Dniester pumped-storage hydropower plant that was commissioned in December 2020. The data exclude the temporarily occupied Autonomous Republic of Crimea, the city of Sevastopol and uncontrolled parts of the Donetsk and Luhansk regions.

In 2019, the total annual electricity generation in Ukraine amounted to 153.8 TWh.[9] Electricity generation had been rising for two years, from 154.82 TWh in 2016 to 159.3 TWh in 2018, but decreased steeply in 2019 by 5.4 TWh compared to 2018.[3,9] This decrease was due to an overall reduction in electricity consumption as well as a decline in the country's industrial output.[9] In particular, there was a decrease in electricity production from nuclear and thermal power plants. On the other hand, the production of electricity from renewable sources doubled, increasing by 2.8 TWh.[9] However, the main sources of electricity generation in 2019 were still nuclear (54 per cent) and thermal (36 per cent) power plants. Hydropower and other renewable energy sources accounted for 5 per cent and 4 per cent of the total electricity generation, respectively (Figure 2).[9]

Figure 2. **Annual Electricity Generation by Source in Ukraine in 2019 (TWh)**



Source: Ukrenergo[9]

Ukraine imports approximately 83 per cent of its domestically consumed oil supplies, 33 per cent of natural gas and 50 per cent of coal. At the same time, the country's energy sector is diversified, as no fuel represents more than 30 per cent of the energy mix. Overall, domestic production covers almost 65 per cent of the total energy needs of Ukraine.[10]

Hydropower also plays a key role in the country's energy mix, represented primarily by large-scale hydropower plants (HPPs) and pumped-storage hydropower plants (PSHPs). The latter cover peak loads, control frequency and power and provide a mobile emergency reserve of power for the Integrated Power System (IPS) of Ukraine.[3,11,12] Today, there are 10 large HPPs (with installed capacity over 10 MW) in Ukraine. Six of them, with 3,908.44 MW of combined installed capacity, are located on the Dnieper, two HPPs operate on the Dniester (742.8 MW), one HPP on the Tereblya and Rika Rivers (27 MW) and one on the Southern Bug (11.5 MW).[9] Moreover, three large PSHPs with 1,609.5 MW of combined installed capacity have been commissioned: Kyiv PSHP (235.5 MW), Dniester PSHP (972 MW) and the first two units of the Tashlyk PSHP (302 MW). Large hydropower provides over 98 per cent of all hydropower production in Ukraine. At the same time, the share of hydropower in the renewable energy mix of Ukraine decreased almost twice between 2010 and the first quarter of 2020, from 98.4 per cent to 44.9 per cent.[13] This was a result of an increase in installed capacity of other renewable energy technologies, mainly solar power (Figure 1).

The IPS of Ukraine is central to the country's electric power industry. The IPS consists of power plants, substations, trunk/main power transmission and distribution lines (Table 1). The state-owned Enterprise National Power Company Ukrenergo is responsible for the operational and technological control of the IPS and the transmission of electricity via trunk power lines from the generating plants to the distribution networks.[3,9] The total amount of electricity transmitted by the Ukrenergo network amounted to 95.2 TWh in 2019.[9] The electrification rate in Ukraine is 100 per cent.[9,14] All consumers and producers can easily connect to the country's power grid. The biggest consumer of electricity is the industrial sector, accounting for 42.6 per cent of consumption in 2019.[9] Residential and public utility sectors together consume approximately 41.8 per cent of the total (Figure 3). Additionally, Ukraine ensures electricity exchange with the energy systems of other European countries (Table 2).[9]

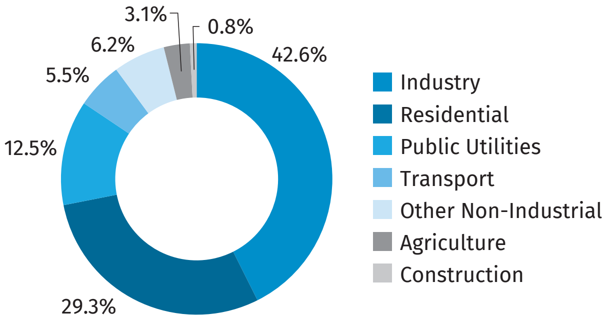
Table 1. **Main Networks of Ukrenergo in 2019**

Voltage class	*Length of power lines (km)*	*Substations*	
		Number	*Power (MVA)*
750 kV	4,403	9	18,736
500 kV	375	2	1,753
400 kV	339	2	2,008
330 kV	12,980	88	49,598
220 kV	3,019	33	9,207
110 kV	458	6	376
35 kV	122	-	-
Total	**21,696**	**140**	**81,678**

Source: Ukrenergo[9]

Note: 34 substations are located in the temporarily occupied and uncontrolled territories.

Figure 3. **Electricity Consumption in Ukraine by Sector in 2019 (%)**



Source: Ukrenergo[9]

Table 2. **Export and Import of Electricity in Ukraine in 2019 (TWh)**

Country	*Export*	*Import*
Belarus	0.0	0.9
Hungary	3.9	0.6
Moldova	0.6	0.0
Poland	1.4	0.0
Romania	0.4	0.02
Russian Federation	0.0	0.3
Slovakia	0.1	0.9
Total	**6.5**	**2.7**

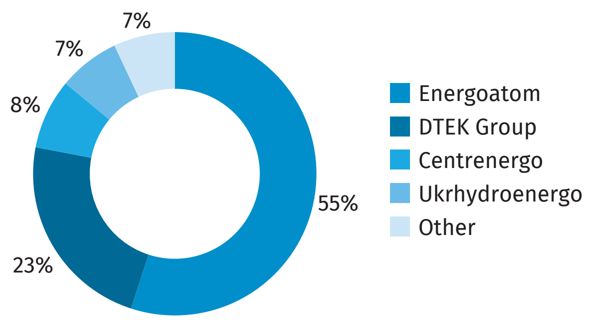
Source: Ukrenergo[9]

As of the end of 2019, 53 per cent of electrical equipment of the Ukrenergo substations had been in operation for over 25 years, 66 per cent of power transmission lines for more than 50 years and almost 5 per cent of 220–750 kV transmission lines needed complete replacement or reconstruction. The average service life of basic electrical equipment (autotransformers, limiters, compressors) is 25 years and that of power lines is 50 years. A total of 72 technological violations occurred in the Ukrenergo network in 2019. Thirty-three violations occurred due to natural disasters and outside interference, 10 violations due to erroneous actions of staff and deficiencies in maintenance and 29 due to other reasons. Technological losses during the transmission of electricity through the main networks amounted to 3.6 TWh.[9]

The Government of Ukraine plans to develop the electricity sector based on the Energy Strategy of Ukraine for the period until 2035 "Safety, Energy Efficiency, Competitiveness" (from 15 March 2006).[15] The essential task of the Energy Strategy is to reduce the energy consumption of the economy by half by 2035 and to boost the production of both traditional and alternative renewable energy sources. According to the document, total electricity production is to increase to 195 TWh, including an increase in nuclear power production to 94 TWh (48 per cent of the total), in wind and solar power generation to 25 TWh (13 per cent) and in hydropower to 13 TWh (7 per cent). The remaining 63 TWh (32 per cent) is to be produced by thermal power plants. The said document also includes the integration of the IPS of Ukraine into the European Network of Transmission System Operators for Electricity, ENTSO-E.[15] The main vectors of the country's hydropower development are also considered in the Hydropower Development Programme for the period until 2026.[11] In particular, this Programme provides for the completion of the Dniester and Tashlyk PSHPs, the construction of the Kaniv PSHP and the Kakhovka HPP-2, the construction of six new HPPs on the Dniester River as well as rehabilitation and construction of numerous SHP plants.[11,12]

According to the current legislation of Ukraine, nuclear power plants, large HPPs, PSHPs and main transmission power networks of the IPS are state-owned enterprises.[16] The main electricity producer in the country is Energoatom, a state-owned company. The main player in the hydropower sector is Ukrhydroenergo, likewise a state-owned company. One of the key players in the country's thermal power generation is the state-owned Centrenergo (Figure 4).[17] At the same time, the majority of thermal power plants, all non-traditional renewable energy plants and, in particular, SHP plants, are privately owned.

Figure 4. **Share of Electricity Generation by Producer in Ukraine in 2019 (%)**



Source: OECD[17]

Ukrhydroenergo operates the Dnieper and Dniester cascades of large HPPs and PSHPs. The Tashlyk PSHP is operated by Energoatom. The SHP sector in Ukraine is dominated by numerous domestic companies (LLC "HIDROENERHOINVEST", LLC "ENERHOINVEST", FEA "NOVOSVIT", LLC "RENER" and others) as well as foreign private stakeholders, including Norway's AICE Hydro A/S and Austria's ANDRITZ Hydro, a subsidiary of ANDRITZ Technology Group.[17,18] The main incentive for foreign players to invest in this segment of the energy sector of Ukraine is eligibility for the country's feed-in tariff (FIT) for SHP. One of the major players in the wind power segment is DTEK Renewables, the operating company that manages the DTEK Energy Group's assets in the renewable energy sector. In turn, DTEK Energy is one of the main stakeholders in thermal power. DTEK Renewables is also a key solar power producer in Ukraine.[17] Additionally, DTEK Energy exports electricity to countries of the European Union (EU) through the Burshtyn Island thermal power plant ("Island"). The "Island" is connected to the European ENTSO-E network and functions separately from the main part of the IPS.[3,9] The privately-owned SEC Biomass Ltd. and SALIX Energy represent key biomass producers in the country.[17]

The key institutions governing the energy sector of Ukraine and providing a regulatory framework include the Cabinet of Ministers of Ukraine (CMU), the Ministry of Energy and Coal Industry (MECI) and the National Energy and Utilities Regulatory Commission (NEURC). The CMU supervises state policy in the energy sector and electricity industry, while the MECI is responsible for energy policy formation and implementation, including the development of the Energy Strategy of Ukraine for the period until 2035, tracking and monitoring results and submitting annual progress reports to the CMU and the National Security and Defence Council. The MECI additionally reports to the Verkhovna Rada (parliament) and the Presidential Office. Along with the CMU and the MECI, the NEURC plays a central role in regulating the country's energy sector, especially in setting tariff policies and formulating energy prices.[3,17,19]

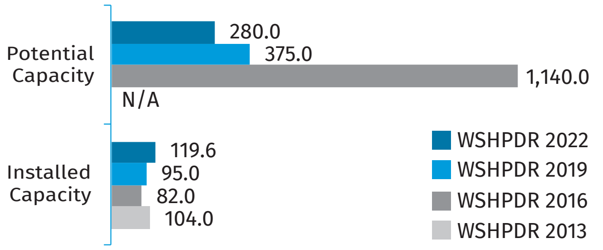
Tariffs for electricity consumers in Ukraine differ for household and non-household (industrial) consumers. For household consumers, a flat nationwide tariff of UAH 1.68 (USD 0.06) per 100 kWh, inclusive of VAT, was set as of 1 January 2021, replacing previous discounted tariffs for several categories of consumers.[20] For non-household consumers, tariffs are set individually by the electricity provider, of which there are typically one or several per administrative region. Additionally, tariffs are set according to one of two voltage classes: first class, which covers consumers connected to lines of 27.5 kV and above, and second class, which covers consumers connected to lines of below 27.5 kV. Prices (exclusive of VAT) range between UAH 16.27 and UAH 344.48 UAH (USD 0.59–12.41) per 1,000 kWh for first-class consumers and between UAH 245.09 and UAH 1508.28 (USD 8.83–54.34) per 1,000 kWh, varying across providers and regions.[21,22]

SMALL HYDROPOWER SECTOR OVERVIEW

Ukraine defines SHP as hydropower plants with less than 10 MW of installed capacity.[16,19] Additionally, hydropower facilities with less than 200 kW of installed capacity are classified as micro-hydropower and those within the 200 kW–1 MW range as mini-hydropower. This classification is related to the establishment of the FITs value. The FIT is the largest for SHP plants with a capacity of up to 200 kW and the smallest for SHP plants with a capacity of 1 MW or more.[18,23]

In 2020, there were 167 SHP plants in Ukraine with a total installed capacity of 119.618 MW.[18,24,25] The potential is estimated at 280 MW, indicating that approximately 42.7 per cent of known potential has been developed.[26] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity increased by 25.9 per cent and potential capacity decreased by 25.3 per cent (Figure 5). The increase in installed capacity has been due to recently-commissioned new SHP plants; in particular, 15 new plants were commissioned in 2019 (Table 3). The estimate of potential capacity has been revised downwards in response to a 2019 study of potential SHP capacity in Ukraine carried out by the World Bank.[26]

Figure 5. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Ukraine (MW)**



Source: *WSHPDR 2019*,[3] Energo.ua,[18] Stefanyshyn,[24] RENER Group,[25] World Bank,[26] *WSHPDR 2013*,[27] *WSHPDR 2016*[28]

Table 3. **List of Selected Recently Commissioned Small Hydropower Plants in Ukraine**

Name	*Location*	*Capacity (MW)*	*Head*	*Plant type*	*Operator*	*Launch year*
Brustury-anka	Brustury-anka River, Lopukhovo	1.00	16.5	Diversion, run-of-river	"RENER" Group	2016
Janowiec	Janowiec River, Rus'ka Mokra	0.99	86.21	Diversion, run-of-river	"RENER" Group	2017
Brustury-anka 2	Brustury-anka River, Ust-Chorna	0.99	16.15	Diversion, run-of-river	"RENER" Group	2018
Kapus-tyanska	Kapus-tyanska Stream, Zapor-izhzhia	0.48	32.00	Storage, run-of-river	LTD "HI-DROPAU-ER-1"	2018
Poltava Hidro	Poltava region, Horbanivka	0.19	36.00	Diversion, run-of-river	LTD "POLTAVA HIDRO"	2018
Velyka Bahachka	Psel River, Velyka Bahachka	0.45	3.40	Storage, run-of-river	LTD "HI-DROEN-ERHO-RE-SURS"	2019
Tetiivska	Roska River, Tetiiv	0.13	3.00	Storage, run-of-river	LTD "HI-DROEN-ERHO-RE-SURS"	2019

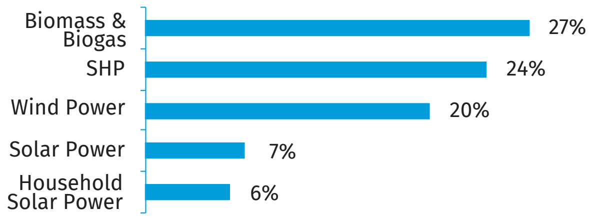
Name	*Location*	*Capacity (MW)*	*Head*	*Plant type*	*Operator*	*Launch year*
Ispaska	Cheremosh River, Ispas	0.20	3.50	Diversion, run-of-river	LTD "ENERHOINVEST"	2019
Velyko Yablunivska	Tyasmin River, Velyka Yablunivka	0.08	3.00	Storage, run-of-river	LTD "ZHK"	2019
Salkivska	Southern Buh River, Salkove	0.20		Storage, run-of-river	IE "BOYKO YE.L."	2019
Velykohayivska	Hnizna River, Dychkiv	0.15	4.10	Storage, run-of-river	LTD "OS-NOVA"	1952/ 2019
Lyuks 2	Seret River, Myshkovychi	0.08	3.00	Storage, run-of-river	PSE "LYUKS"	2019
Rener 1	Malyi Stream, Kostylivka	1.00		Diversion, run-of-river	LTD "RENER"	2019
Rener 2	Velykyi Stream, Kostylivka	1.00		Diversion, run-of-river	LTD "RENER"	2019
Orlove	Yatran River, Orlove	0.18	3.00	Storage, run-of-river	LTD "HIDROENERHOINVEST"	2019
Pylypchanska	Ros River, Pylypcha	0.93	3.00	Storage, run-of-river	LTD "HIDRO-INVEST"	2019
Doroshivska	Murafa River, Doroshivka	0.09		Storage, run-of-river	LTD "NYU ENERDZHY"	2019
Velyka Liubashivska	Zamchisko River, Velyka Liubasha	0.08	2.80	Storage, run-of-river	PJSC "RIVNEVTORMET"	2019
Matyushivska	Rostavytsia River, Matiushi	0.10	4.30	Storage, run-of-river	LTD "UKRBIOPROMPOSTACH"	2019
Slavutska	Goryn River, Slavuta	0.20		Storage, run-of-river	LTD "SLAVHIDRO"	2019

Source: Energo.ua,[18] Stefanyshyn,[24] RENER Group[25]

According to the National Renewable Energy Action Plan of Ukraine for the period until 2020, it was planned to achieve an increase in SHP capacity of up to 150 MW by 2020 through the modernization of existing facilities, the restoration of old SHP plants and the construction and commissioning of new ones.[29] That estimate was not as large as a previous estimate of 1–2 GW earlier considered by UkrHydroProject (UHP), the largest engineering company in the field of hydropower and hydraulic construction in Ukraine.[26,30] In turn, according to the first version of the Energy Strategy of Ukraine for the period until 2030, the SHP potential capacity of Ukraine was estimated at 1,140 MW (as mentioned in the *WSHPDR 2019*).[15,3] However, these estimates may have been based on the old definition of SHP and included projects up to 30 MW.[3,15,30] The recent results of a market assessment of SHP rehabilitation in Ukraine by the World Bank indicated a total feasible technical potential for SHP development in Ukraine (including currently installed capacity) of approximately 280 MW.[26]

In 2019, 157 SHP plants, with a total installed capacity of 114 MW, generated 242 GWh of electricity in Ukraine. The share of SHP plants in the non-traditional renewable energy mix (including solar power, wind power and biomass) was 4.1 per cent. The installed capacity utilization rate of SHP was 24 per cent in 2019 (Figure 6).[31]

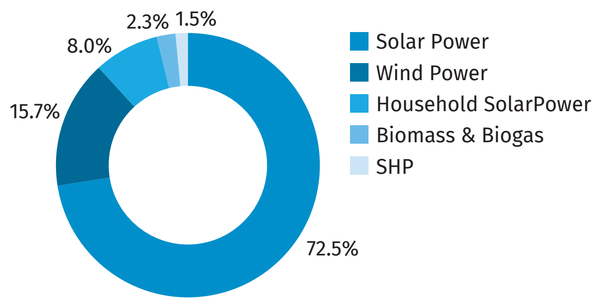
Figure 6. **Installed Capacity Utilization Rate of Renewable Energy Operating under the FIT in Ukraine in 2019**



Source: SAEE[31]

The share of SHP installed capacity in the IPS of Ukraine is marginal compared to other renewable sources (Figure 7).[30] Between 2010 and the first quarter of 2020, there was a significant reduction in the share of SHP in non-traditional renewable energy installed capacity mix — from 43.0 per cent to 1.5 per cent.[13] This was a result of the growing capacities of other renewable sources, in particular solar power.[32]

Figure 7. **Share of Non-traditional Renewable Energy Sources in the Installed Capacity of Ukraine in 2020 (%)**



Source: SAEE[32]

Note: Excluding the temporary occupied and uncontrolled territories.

Between 2013 and 2019, the installed capacity utilization rate of SHP plants operating under the FIT in Ukraine decreased from approximately 44 per cent to 24 per cent. Such a decrease is explained first of all by the reduction of water discharge in the rivers on the territory of Ukraine, which occurred during that period. Secondly, it might have been a result of the insufficient substantiation of new projects, in particular, due to the overestimation of feasible hydropower potential.[33] There was also a 25 per cent reduction in the cost of electricity production by SHP plants for the period of 2012–2019. However, this was the lowest reduction in production cost among all types of renewable energy in Ukraine, which is likely explained by the significant difficulties in obtaining building permits relative to other renewable energy plants.[34,35] Besides, given the poor condition of the infrastructure of older SHP plants, the low hydropower potential of Ukrainian rivers and the FIT rates, many Ukrainian entrepreneurs focus on developing only the smallest SHP plants with a capacity of up to 200 kW.[18,34] Several ongoing and planned SHP projects are displayed in Table 4.[36]

Table 4. **List of Selected Ongoing and Planned Small Hydropower Projects in Ukraine**

Name	*Location*	*Capacity (MW)*	*Head*	*Plant type*	*Operator*	*Planned launch year*	*Development stage*
Dobrotvirska	Western Buh River, Stary Dobrotvir	1.00	7.8	Storage, diversion, run-of-river	LLC "AKVARESURS-2"	2021–2022	Ongoing
Ternivska	Sinyukha River, Ternivka	0.20	2.0	Storage, run-of-river	PE "BENCHYK MLYN"	2021–2022	Planned
Kurchytska	Sluch River, Kurchytsya	0.20	2.5	Storage, run-of-river	"WATERSTRUM" LLC	2021–2022	Planned
Vygodska	Svicha River, Vygoda	0.40	5.0	Storage, diversion, run-of-river	"EKOENERHETYKA" LLC	2021–2022	Planned
Stril'chyntska	Southern Buh River, Stril'chyntsi	0.20	6.0	Storage, diversion, run-of-river	"AGROGES" LLC	2021–2022	Planned

Source: Stefanyshyn,[24] Ministry of Environmental Protection and Natural Resources[36]

One prospective area for SHP development is installation of SHP facilities on existing man-made infrastructure, such as drainage and irrigation canals, outflow pipes of non-powered dams and wastewater runoff pipes. Two such pilot projects have already been implemented at wastewater treatment facilities in Ukraine. The first one, implemented in 2018 at the Suprunivska sewage treatment plant in Poltava, has a capacity of 190 kW and generates up to 1.24 GWh per year. The second pilot SHP plant was also implemented in 2018 on the Kapustyansky reservoir in the city of Zaporizhzhia, with a capacity of 484 kW and generates up to 2.1 GWh of electricity per year.[18,24]

RENEWABLE ENERGY POLICY

Renewable energy sources including SHP are eligible to benefit from the FIT in Ukraine.[16] The application of FITs to renewable energy sources, improvement of the energy efficiency of large combustion plants (thermal power and cogeneration plants) and encouragement of the implementation of low-carbon technologies are considered the main components of the policy on climate change in Ukraine.[3,16,37] However, in 2019, there were some changes in Ukrainian legislation on FITs for renewable energy sources. On 25 April 2019, the Verkhovna Rada of Ukraine adopted the Law On Amendments to Certain Laws of Ukraine on Ensuring Competitive Conditions for Electricity Production from Renewable Energy Sources.[38] The law introduced a new support scheme for renewable energy, a reduction of the FIT and a procedure for conducting green auctions to identify business entities eligible for support, including compensation for participation in such auctions.[16] The passage of this new law was deemed necessary because the previously-established FIT for green electricity was believed to be excessively high, in particular for solar power plants, leading to an excessive price burden for Ukrainian electricity consumers, which would only increase as new power plants are commissioned.[16] The law was subsequently superseded by the Memorandum of Understanding on the Settlement of Problematic Issues of the Ukrainian Renewable Energy Sector, signed into law on 10 June 2020.[39] According to the Law on Amendments, the existing FIT scheme (Table 5) is guaranteed until 2030; however, with regard to the FIT rates for various renewable energy sources, the more recent Memorandum of Understanding provides for several tariff reductions, as displayed in Table 6.[38]

In 2020, due to the economic crisis in the country, tariffs for electricity produced at facilities using alternative energy sources were reviewed quarterly by the NEURC. Tariffs were established individually for electricity producers, taking into account the surcharge for compliance with the level of use of Ukrainian-made equipment. Currently, NEURC resolution No. 2877 of 31 December 2020 is valid, with tariffs for producers ranging between UAH 1.994 and UAH 8.408 (USD 0.072–0.300) per kWh.[23] However, the minimum FITs for SHP, based on the installed capacity, are maintained at the previous level (Table 5).[18,23,38]

Maintaining its focus on energy-saving technologies and renewable energy, the Energy Efficiency Agency of Ukraine is planning to implement a market for green bonds in order to stimulate interest in renewable energy development. This initiative will involve the development of a package of primary and secondary draft laws that will provide the guidelines for green bonds, reducing barriers to an otherwise encouraging green investment in Ukraine.[16] With regard to SHP specifically, in December 2020 NEURC renewed the green tariffs for electricity produced using SHP by various economic entities, taking into account the capacity of installations and surcharges for the use of Ukrainian-produced equipment.[18,23] These tariffs vary from 0.1045 EUR/kWh (0.13 USD/kWh) to 0.1939 EUR/kWh (0.23 USD/kWh) (excluding VAT) (Table 7).[18,23]

Table 5. **Minimum FITs for Renewable Energy Producers (2018)**

Renewable energy source	*Category/installed capacity*	*Minimum FIT (EUR/kWh (USD/kWh), exclusive of VAT) for power plants by commissioning date*		
		1 Jan 2017 – 31 Dec 2019	*1 Jan 2020 – 31 Dec 2024*	*1 Jan 2025 -- 31 Dec 2029*
Wind power	≤ 600 kW	0.058 (0.07)	0.052 (0.06)	0.045 (0.05)
	600–2,000 kW	0.068 (0.08)	0.060 (0.07)	0.053 (0.06)
	> 2,000 kW	0.102 (0.12)	0.091 (0.11)	0.079 (0.10)
Biomass/ biogas		0.124 (0.15)	0.112 (0.13)	0.099 (0.12)
Solar power	Ground-mounted	0.150 (0.18)	0.135 (0.16)	0.120 (0.14)
	Roof-mounted	0.164 (0.20)	0.148 (0.18)	0.131 (0.16)
Hydro-power	Micro-hydropower (< 200 kW)	0.175 (0.21)	0.157 (0.19)	0.140 (0.17)
	Mini-hydropower (200–1,000 kW)	0.140 (0.17)	0.126 (0.15)	0.112 (0.13)
	Small hydropower (1–10 MW)	0.105 (0.13)	0.091 (0.11)	0.084 (0.10)
Geothermal power		0.150 (0.18)	0.135 (0.16)	0.120 (0.14)

Source: Vovchak et al.[40]

Table 6. **Amendments to FITs**

Commissioning date	*FIT reduction*		
01 Jul 2015 – 31 Dec 2019	Solar power ≥ 1 MW	Solar power < 1 MW	Wind power
	15%	10%	7.5%*
From 1 Jan 2020	2.5% (irrespective of installed capacity)		
Before 01 Jul 2015	The FIT is capped at the level of the FIT for ground solar installations of > 10 MW commissioned before 31 Mar 2013, decreased by 15%		

Source: Teush, S.[39]

Note: *except where the installed unit capacity of a wind turbine is less than 2 MW.

Additional incentives available to investors and producers of renewable energy include exemptions from VAT and customs duties for imports of raw and processed materials, components and equipment that will be used in the generation of renewable energy.[3]

Table 7. **Distribution of FIT Rates for Small Hydropower in Ukraine (2021)**

FIT rate (EUR/kWh (USD/kWh))	*SHP plants*	
	Number	*Share (%)*
0.1045 (0.13)	4	2.4
0.1163 (0.14)	71	42.5
0.1395 (0.17)	18	10.8
0.1551 (0.19)	8	4.8
0.1700 (0.20)	3	1.8
0.1745 (0.21)	44	26.3
0.1939 (0.23)	19	11.4
Total	**167**	**100.0**

Source: Energo.ua[18]

In general, the national renewable energy policy and environmental regulations in the country have not changed since the release of the *WSHPDR 2019*.[3] Recent developments include the work on the practical implementation of The Law of Ukraine On Environmental Impact Assessment (EIA) and the adoption of The Law of Ukraine On Strategic Environmental Assessment (SEA).[41,42] All current changes in the country's renewable energy policy and the protection, conservation and use of natural resources take into account current EU acquis and/or international agreements, in particular, the EU Renewable Energy Directive, the Environmental Impact Assessment Directive, the Strategic Environmental Assessment Directive, the Water Framework Directive, the Paris Agreement on climate change as well as the Aarhus, Espoo and Berne Conventions.

In addition, the Government of Ukraine has started the process of developing a National Framework Strategy for Adaptation to Climate Change. In November 2020, the first meeting of the Climate Change Adaptation Working Group was held to discuss the country's strategy for adaptation to climate change, the climate risks threatening the economy and how to integrate the experience of other cities and ecosystems into the national climate change adaptation strategy.[43] The Government of Ukraine will be supported in this process by the EU project EU4Climate, which is being implemented by the United Nations Development Programme (UNDP) in Ukraine.[43,44]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

At the moment, there are no Government plans or programmes specifically targeting SHP in Ukraine. In general, design, construction and reconstruction of hydraulic and other SHP structures must be carried out in accordance with the current building codes.[45] In addition to the general legal aspects pertaining to SHP planning, construction, operation as well as distribution, environmental and water legislation applies.[16] The Water Code of Ukraine provides regulations governing the planning, construction and operation of all hydropower plants regardless of the scale.[46] This Code specifies regulations pertaining to land allocation as well as obtaining authorization for operating facilities that use water resources.[3,16,46] Furthermore, it is necessary to comply with the Law on EIA.[41] The law establishes legal and organizational principles for EIA to be carried out for all hydropower plants regardless of installed capacity. The Law on EIA incorporates the European model of EIA and significantly expands the range of facilities that are subject to assessment. Additionally, in comparison with the earlier Law on Ecological Expertise, the EIA procedure itself has become more extensive.[16]

Regardless of the existing legal and regulatory framework, there are still many examples of non-compliance with existing building codes, violations of the Water Code's requirements as well as the requirements of the Law on EIA and the Law on SEA. [41,42,45,46] Violations are committed by both developers and regulatory agencies.[47] It should be noted that in Ukraine, hydropower development carries significant environmental and water risks because of the scarcity of water resources.[33,48] Therefore, compliance with environmental requirements can be considered as one of the main conditions for the planning, construction, distribution and operation of SHP plants in Ukraine.

One primary issue with the construction of new SHP plants, especially on mountain rivers, is disturbance of the natural state of the rivers' ecosystems.[16] Numerous examples of damage to river ecosystems caused by both rehabilitated SHP plants on rivers in the plain region of Ukraine (including the Southern Bug, Sluch, Ros and Seret) and by new SHP plants built recently on the small rivers in the Ukrainian Carpathians (the Krasna, Rika and Shypit) have been recorded.[48] For example, in 2017 the Chizhivska SHP plant near the city of Novograd-Volinskiy was implicated in the extreme decline of water levels in the Sluch River, requiring the temporary suspension of the plant's operation and a subsequent resumption of operation at reduced levels of water consumption.[49] The World Wildlife Fund (WWF) in Ukraine has repeatedly emphasized that the uncontrolled construction of SHP plants in the country can lead to the extinction of unique fish species and other aquatic organisms, deterioration of river water quality and changes in the rivers' hydro-morphological regimes, drainage and other characteristics. These impacts can also lead to increased social tensions and second-order environmental damage.[50] Although investors are keen to promote SHP as an environmentally-friendly alternative to large hydropower and other energy sources, in the Ukrainian context, it is not clear whether the impact of SHP plants on the environment is necessarily less than that of large hydropower plants relative to the energy produced, particularly in the case of reservoir-type SHP plants.[12,13,48,51]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change is a potentially significant threat to the Ukrainian economy, in particular to its strategically important and growing agricultural sector. Current climate change trends, if they continue, could lead to 70 per cent of Ukrainian agricultural lands requiring additional irrigation, increasing the total irrigation requirement by over a third of what it is today. Additionally, parts of southern Ukraine are now at risk of desertification.[4] The water shortage issue may also be a critical one for the country's hydropower sector.[48] Current hydrological studies show that climate change has been affecting the water regime of rivers flowing within Ukraine. By the middle of the 21st century, reduction of essential water resources is expected on the plains territory of Ukraine, where the majority of the operating hydropower plants and SHP plants are situated.[18,52] Because of a reduction of river runoff, particularly during the low-flow period, water use by existing hydropower plants on the Dnipro, Dniester, Southern Bug, Sluch and other rivers is already being restricted by limits.[44] In turn, adaptation measures to ensure a sustainable use of hydropower might require additional river runoff regulation in order to avoid affecting the environment and reducing access to water resources for other water users.[48]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Overall, the current regulatory framework of Ukraine provides good opportunities for the development of SHP in the country. At the same time, environmental problems associated with SHP plants could continue to be a significant challenge in the future if not properly addressed.

The main barriers to SHP development in Ukraine can thus be summarized as being two-fold:

- Poor reputation of SHP among some communities and environmentalists due to environmental issues caused by previous unsuccessful SHP projects. The failure of these projects can be attributed to insufficiently comprehensive EIAs that did not properly analyse and map out alternative options and implement appropriate compensatory measures;
- The country's relatively poor natural hydropower potential, one of the lowest in the world in the case of local rivers. Small and medium-sized rivers flowing through the territory of Ukraine show a relatively low and uneven runoff (up to 70 per cent or more of their annual runoff occurs during short periods of floods). In addition, most rivers where SHP plants are situated flow on the plains, with relatively small height difference from source to mouth. For example, for rivers of the Dnieper basin, it does not exceed 50–70 metres, and in the Southern Bug basin is approximately 100–150 metres. In the Carpathians, rivers have a slightly greater overall height difference downstream, of approximately 300–400 metres.[33,35,47,48,49,50]

One potential enabler for SHP development in Ukraine is the so-called hidden hydropower potential, namely, relating to the outflow of non-powered dams, municipal and industrial reservoirs and ponds, sewage and wastewater treatment runoff pipes and other man-made infrastructure for the distribution of water for agricultural or other purposes. This hidden hydropower potential has not yet been thoroughly studied, but could boost the implementation of successful SHP projects while reducing the potential of adverse environmental impacts.[35]

Ukraine needs both national and regional programmes on SHP development. These programmes should be developed with the involvement of all stakeholders including scientists, local communities and non-governmental organizations to ensure the coordination of different concerns, the making of knowledge-based decisions and the finding of feasible trade-offs. The programmes should be also adopted taking into account the requirements of the Law of Ukraine on SEA, making it possible to determine no-go areas for hydropower development and also unlocking the hidden hydropower potential described above.[42]

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4.2. Northern Europe

Countries: Denmark, Estonia, Finland, Iceland, Ireland, Latvia, Lithuania, Norway, Sweden, United Kingdom

INTRODUCTION TO THE REGION

The electricity sectors of countries in Northern Europe are highly integrated due to the membership of most countries in the region in the European Union (EU), with the exception of Norway and the United Kingdom, as well as the participation of all countries in the region with the exception of the United Kingdom in the Energy Community, which seeks to harmonize the legal and regulatory frameworks governing the electricity sectors of member countries. Additionally, all countries in Northern Europe are connected to the European Network of Transmission System Operators for Electricity (ENTSO-E), which ensures the synchronous operation of their national electricity grids. Other countries' electricity sector integration with the United Kingdom, previously significant, decreased following the latter's exit from the European Union.

Electricity access in Northern Europe is universal and the electricity sectors of the countries in the region are some of the most diversified in the world with a high degree of integration of renewable energy sources (RES). At the same time, regional countries have adopted different strategies with regard to developing their national energy mixes. Among non-renewable energy sources, gas-fired thermal power plants are the leading source of electricity generation in the United Kingdom, and thermal power forms the mainstay of electricity generation in Estonia and Ireland. The main source of generation in Finland is nuclear power, which also accounts for a significant share of generation in the United Kingdom and Sweden. RES in the region are represented by wind power, hydropower, solar power, geothermal power and bioenergy. Wind power plays a particularly important role in the region. In contrast to many other parts of the world, in Northern Europe wind power outpaces solar power, in terms of both installed capacity and generation, by a significant margin. Wind power is the single-largest source of electricity generation in Denmark and Lithuania, while the United Kingdom leads the region in wind power generation and Sweden in installed wind power capacity. Geothermal power is a major energy source in Iceland, which derives approximately one third of its annual generation from geothermal power.

Hydropower is the leading source of electricity generation in Sweden, Iceland, Latvia and Norway, and plays an important supplementary role in the electricity sectors of other countries in the region with the exception of Denmark and Estonia, where its share of total installed capacity and generation is minor.

An overview of the electricity sectors of countries in the region is provided in Table 1.

Table 1. **Overview of Northern Europe**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Denmark	6	100	100	15,489	28,273	7	17
Estonia	1	100	100	2,506	5,957	8	30
Finland	6	100	100	17,732	66,043	3,273	12,239
Iceland	0.4	100	100	2,923	19,489	2,096	13,462
Ireland	5	100	100	11,021	31,977	235	933
Latvia	2	100	100	3,100	5,720	1,586	2,598
Lithuania	3	100	100	3,699	11,100	128	324
Norway	5	100	100	37,688	154,200	33,011	141,593
Sweden	10	100	100	43,669	165,800	16,286	70,600
United Kingdom	67	100	100	75,810	311,997	4,372	8,156
Total	-	-	-	**213,637**	-	**61,002**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) universally adopted by the countries in Northern Europe is in line with that used by the EU, which defines SHP as hydropower plants with an installed capacity of up to 10 MW.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Northern Europe (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (<10 MW)*	*Potential capacity (<10 MW)*
Denmark	Up to 10 MW	7.0	9.8	7.0	9.8
Estonia	Up to 10 MW	8.0	10.0	8.0	10.0
Finland	Up to 10 MW	297.5	585.5	297.5	585.5
Iceland	Up to 10 MW	66.1	3,742.0	66.1	3,742.0
Ireland	Up to 10 MW	58.5	70.7	58.5	70.7
Latvia	Up to 10 MW	28.0	96.0	28.0	96.0
Lithuania	Up to 10 MW	26.9	57.9	26.9	57.9
Norway	Up to 10 MW	2,924.0	7,162.0	2,924.0	7,162.0
Sweden	Up to 10 MW	961.0	N/A	961.0	961.0*
United Kingdom	Up to 10 MW	405.0	1,179.0	405.0	1,179.0
Total	-	-	-	**4,782.0**	**13,873.9**

Source: *WSHPDR 2022*[1]

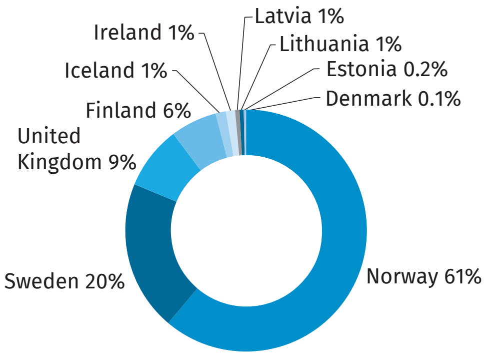
Note: *Based on installed capacity.

The total installed capacity of SHP of up to 10 MW in Northern Europe is 4,782 MW, while the total potential capacity is estimated at 13,873.9 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has increased by nearly 9 per cent, mainly due to a significant expansion of the SHP capacity in Norway. Potential capacity has increased by 28 per cent, mainly due to a newly-available assessment of SHP potential in Iceland.

Apart from Norway, some recent SHP development has taken place in Finland, Ireland, Iceland and the United Kingdom. In other countries in the region, SHP development has stalled due to the saturation of SHP potential as well as fluctuations in river flow and occasional public opposition to SHP development, which have resulted in stricter environmental standards for SHP plants. In Finland, a slow process of decommissioning existing SHP plants has accelerated over the last few years in the wake of policies aimed at preserving fish migration routes through the removal of barriers, and the installed SHP capacity of the country has been declining accordingly. Additional restrictions on water impoundment have been adopted in Latvia and Lithuania. As a consequence, activity in the SHP sector in many countries of the region has been focused primarily on the refurbishment of existing plants. While regional hydropower generation, and SHP in particular, is expected to receive some short-term benefits from increased snowmelt due to climate change, these benefits are likely to be short-term, while long-term climate trends project an increase in the interannual variability of runoff.

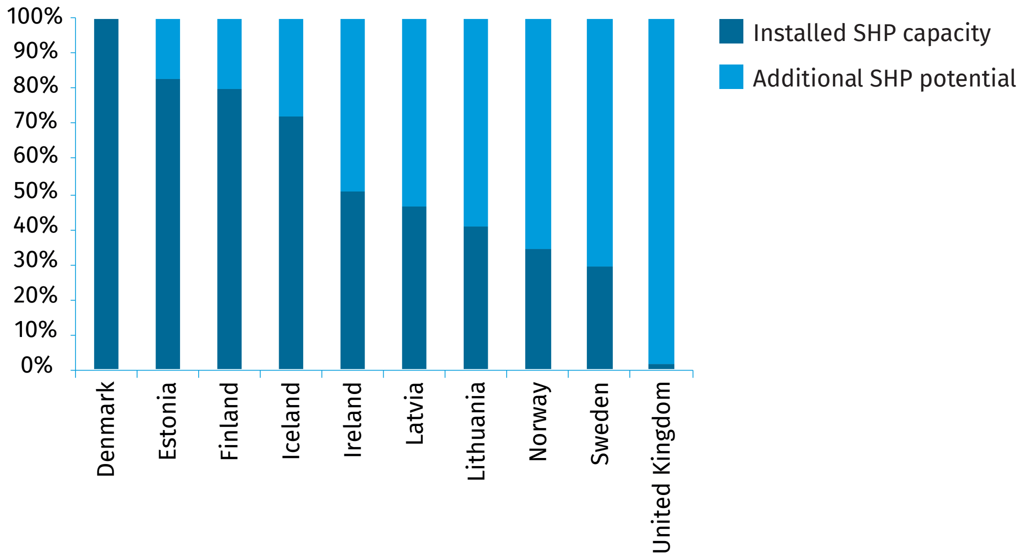
The national share of regional installed SHP capacity of up to 10 MW by country is displayed in Figure 1, while the share of total national SHP potential utilized by countries in the region is displayed in Figure 2.

Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Northern Europe (%)**



Source: *WSHPDR 2022*[1]

Figure 2. **Utilized Small Hydropower Potential up to 10 MW by Country in Northern Europe (%)**



Source: *WSHPDR 2022*[1]

Note: SHP potential of Sweden is assumed to be fully utilized due to a lack of reliable data on SHP potential.

The installed capacity of SHP of up to 10 MW in **Denmark** is 7 MW, provided by two operational SHP plants. A third SHP plant was undergoing restoration as of 2021. Potential SHP capacity in the country is estimated at 9.75 MW on the basis of the total installed capacity of the three plants. With one plant out of operation, approximately 72 per cent of the total potential capacity is being utilized. Further SHP development in the country is unlikely due to unfavourable topographic conditions.

Estonia has approximately 50 operational SHP plants of up to 10 MW with a total installed capacity of 8 MW. Potential SHP capacity in the country is estimated at 10 MW, indicating that 80 per cent has been developed. The potential for further SHP development in Estonia is limited and there are no ongoing projects or specific plans for the construction of additional SHP plants.

Finland has an installed capacity of 297.5 MW for SHP of up to 10 MW from approximately 80 plants, while potential capacity is estimated at 585.5 MW, suggesting that 51 per cent has been developed. Some activity has taken place in the SHP sector in the country recently, with one new plant commissioned in 2021. However, overall installed capacity for SHP of up to 10 MW has declined as some plants have been decommissioned and others refurbished to exceed the 10 MW threshold and therefore excluded from the total. Additional new stream development in Finland is unlikely, and much of the remaining unutilized potential capacity comes from existing but non-operational SHP sites.

The installed capacity of SHP of up to 10 MW in **Iceland** is 66.1 MW, while potential capacity has been recently estimated at 3,724 MW, indicating that approximately 2 per cent has been developed. However, the estimate of potential capacity is theoretical, and the technically and economically feasible SHP potential of the country is unknown. SHP construction in Iceland is actively ongoing, with six new SHP plants commissioned between 2018 and 2019, while several additional projects are in the planning stages.

Ireland has an installed capacity of 58.5 MW for SHP of up to 10 MW, while potential capacity is estimated at 70.7 MW, indicating that nearly 83 per cent has been developed. There are 66 operational SHP plants in addition to hundreds of identified potential SHP sites in the country. Three new SHP projects were under development as of 2021.

There are 147 SHP plants of up to 10 MW in **Latvia** with a total installed capacity of 28 MW. Potential SHP capacity in the country is estimated at 96 MW, indicating that 29 per cent has been developed. No new SHP development has taken place in Latvia in recent years, in part due to negative formal assessments of their environmental impact and public opposition. On the other hand, a total of 367 old water mill sites have been identified in the country that are suitable for the construction of SHP plants.

The installed capacity of SHP of up to 10 MW in **Lithuania** is 26.9 MW, provided by 97 plants. Potential capacity is estimated at 57.9 MW, indicating that 46 per cent has been developed. There has been no new SHP construction in Lithuania in recent years, and there are no ongoing or planned SHP projects in the country. However, a 2019 change in the country's Water Law has opened 170 rivers and streams that had been previously off limits to SHP development.

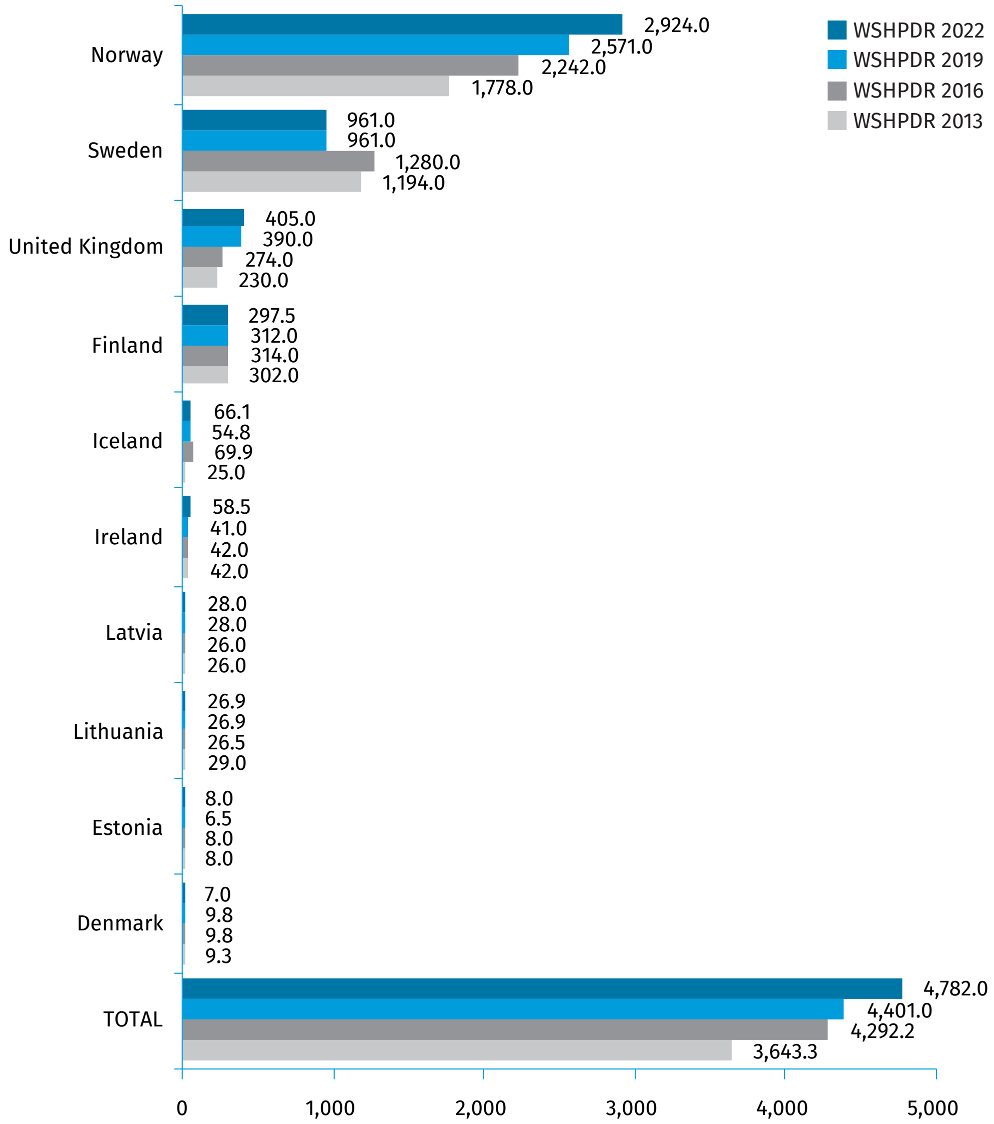
Norway has an installed capacity of 2,964 MW for SHP of up to 10 MW, accounting for 61 per cent of the region's total installed SHP capacity. The potential capacity is estimated at 7,162 MW, indicating that 41 per cent has been developed. The SHP sector of Norway has been expanding rapidly and consistently over the last two decades, with 70 per cent of the country's existing SHP plants constructed between 2000 and 2020. As of 2020, there were 64 SHP plants under construction in the country in addition to another 267 licensed projects.

The installed capacity of **Sweden** for SHP of up to 10 MW is 961 MW. No reliable estimates of potential SHP capacity are available and it is assumed to be fully or almost fully developed, although some evidence suggests it may be double that of current installed capacity. The installed capacity of the country has not changed in several years and any further development is expected to focus on the modernization of existing plants.

The **United Kingdom** has an installed capacity of 405 MW for SHP of up to 10 MW, while the potential capacity is estimated at 1,179 MW, indicating that 34 per cent has been developed. The SHP sector in the country is actively growing with 1,216 new SHP plants commissioned between 2010 and 2019, although the pace of new construction has slowed in recent years. Tens of thousands of potential SHP sites have been identified across the country, with the large majority of potential sites as well as existing SHP plants located in Scotland.

Changes in the installed SHP capacities of up to 10 MW of countries in the region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower up to 10 MW from *WSHPDR 2013* to *WSHPDR 2022* by Country in Northern Europe (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

Climate Change and Small Hydropower

An increase in winter runoff as a result of earlier snowmelt has already been observed in Norway and Finland, and additional increases are expected in the future. The increase of inflow to rivers has been beneficial for hydropower production in these countries. However, the interannual variability of inflow is also expected to increase, with the difference between the driest and wettest winters potentially doubling by 2090. In the Baltic countries, precipitation has been decreasing, although the impact on hydropower has varied. Some negative impacts of increased variability in river flow on SHP production in Latvia and Lithuania have included water impoundment being banned during low-flow periods, as well as SHP operations being suspended entirely in certain cases.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barrier to further SHP development in **Denmark** is the country's flat topography. Taking existing operational and non-operational SHP plants into account, all identified feasible SHP potential in the country is fully developed. Further activity in the SHP sector of the country is likely to be limited to repairs and refurbishment of existing plants.

The potential for additional development of SHP in **Estonia** is limited due to the country's flat topography and strict environmental requirements for new plants. However, some potential exists in the form of abandoned water mills, some of which could be refurbished and converted into SHP plants.

Barriers to SHP development in **Finland** include strict environmental and other regulations, limited profitability and declining snowmelt, which could reduce river flow. However, the latter issue may be offset by projected increases in precipitation. There are a large number of potential SHP sites available for development in the country, many of which are formerly operational plants in need of rehabilitation or comprehensive reconstruction.

Additional SHP development in **Iceland** is complicated by a degree of public resistance to hydropower development in general. Although the country's estimated theoretical SHP potential is enormous, it remains unclear how much of this potential is technically and economically feasible. Enablers for SHP development include rising demand for electricity, a comprehensive framework for hydropower development coupled with specific government initiatives in support of SHP development and projections of increased precipitation as a result of climate change that may benefit hydropower.

One important barrier to the development of SHP in **Ireland** is the lack of recent data on SHP potential, with estimates based on potential sites identified several decades ago, which could have already been developed or no longer feasible for development due to reduced flow or other factors. Some more recent assessments suggest that few undeveloped economically feasible SHP sites remain in the country. Additional barriers include strict environmental regulations, high start-up costs and opposition to SHP from fishing communities. Support for SHP in the form of RES auctions is available, although SHP projects have historically been outcompeted at such auctions by wind and solar power projects. Considerable potential remains in the country for the development of micro-scale hydropower.

Barriers to SHP development in **Latvia** include a negative perception of SHP by both the public and authorities, both due to environmental impacts and the perceived excessive cost to the public of feed-in tariffs (FITs) applied to SHP. Licensing procedures are lengthy and complicated and SHP development in many areas in the country is prohibited entirely. Enablers include the FITs and other incentives, which remain in place despite opposition, and considerable untapped SHP potential, with hundreds of identified sites.

Following a cancellation of existing FITs, there are no incentives for SHP development in **Lithuania**. This has extended the payback period of SHP projects and made investments in the SHP sector less attractive. Additionally, extensive environmental restrictions are in place on SHP construction in protected areas. The major enabler for SHP development in Lithuania is the partial lifting of these restrictions on certain watercourses following amendments to the country's Water Law.

Some challenges faced by the SHP sector in **Norway** include difficulties with grid connections in parts of the country as well as increasing competition from wind power. Nonetheless, the overall atmosphere for SHP development in the country is positive due to favourable market conditions, rising electricity demand and support for RES in the form of electricity certificates, as well as very significant undeveloped potential.

Barriers to SHP development in **Sweden** include a lack of identified undeveloped potential, costly licensing procedures and strict environmental requirements. However, support is available in the form of an electricity certificate scheme shared with Norway and the recognized need for modernizing existing plants.

SHP development in the **United Kingdom** has been hampered by insufficient interest from investors, cessation of FIT support in 2019 and the complicated documentation required for licensing and operation of SHP projects. Enablers for development in the sector include a liberalized electricity market favourable towards small producers, ambitious carbon reduction targets, and very significant remaining undeveloped potential, particularly on old water mills that could be repurposed as SHP plants.

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Denmark

International Center on Small Hydro Power (ICSHP)

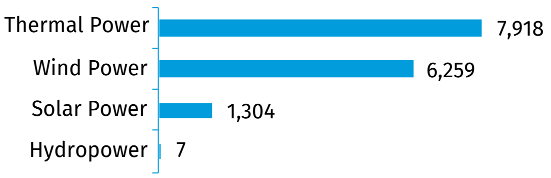
KEY FACTS

Population	5,831,404 (2020)[1]
Area	43,094 km^2[2]
Topography	Denmark is made up of the Jutland Peninsula connected to the European continent and numerous islands varying in size. It has a predominately low-lying, flat terrain with an average elevation of 30 metres above sea level. The landscape features rocky coastlines, several fjords and the presence of various bogs and marshes. The highest peak in the territory is Yding Skovhøj, an old burial mound reaching 173 metres, while the highest natural peak is Møllehøj at 171 metres.[2]
Climate	The climate is temperate with Atlantic, Artic and continental influences. While below-freezing temperatures and snowfall commonly occur in the winters, the gulf stream from the Atlantic maintains the average temperature in January and February at 0 °C, which is considerably warmer than average for the same latitude. Summers are mild and cool, with an average temperature of 16 °C in July, the warmest month.[2]
Climate Change	For a country with low elevation and many islands, an important concern are the rising sea levels, which would cause coastal erosion and floods. In addition, precipitation is expected to increase by up to 40 per cent in the winters, which would intensify the perceivable flooding. As a result of flooding, some bogs, which are naturally efficient at storing carbon, may become too deep, releasing the carbon back into the atmosphere.[3]
Rain Pattern	The average annual precipitation for the country is approximately 640 mm but varies between regions. The southern Jutland region receives an average of 810 mm per year, whereas the islands in the north receive an average of 405 mm per year.[2]
Hydrology	Although Denmark is a country rich in water resources, most of the plentiful rivers are small and slow due to the low elevations. The longest river is the 160-kilometre Gudenåen, which begins in the eastern-central Jutland region and flows north-east to empty into the Randers Fjord. There are also several lakes in the territory with a region of large lagoons in the north-west.[2]

ELECTRICITY SECTOR OVERVIEW

In 2020, the total installed capacity in Denmark was 15,489 MW. Thermal energy including both renewable and non-renewable (biomass, oil, coal and natural gas) accounted for 7,918 MW, or 51 per cent, which comprised 5,544 MW of large-scale units, 1,788 MW of small-scale units and 586 MW of auto-producers. Wind power has been the fastest growing source of energy since 1990 and accounted for 6,259 MW, or over 40 per cent. The remaining 9 per cent was largely solar power with 1,304 MW and some 7 MW of hydropower (Figure 1).[4]

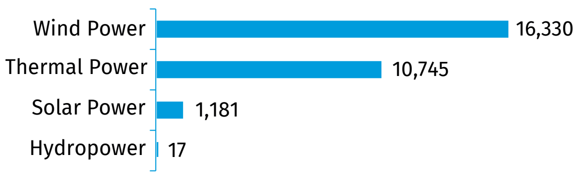
Figure 1. **Installed Electricity Capacity by Source in Denmark in 2020 (MW)**



Source: Danish Energy Agency[4]

In 2020, the total net electricity generation was 28,273 GWh. Wind power generated 16,330 GWh (just under 58 per cent), thermal power including renewable and non-renewable sources generated 10,745 GWh (38 per cent), solar power 1,181 GWh (4 per cent) and hydropower 17 GWh (Figure 2). Denmark both imports and exports electricity, with Norway, Sweden and Germany among the largest trade partners. In 2020, 18,594 GWh of electricity was imported and 11,711 GWh was exported.[4]

Figure 2. **Annual Electricity Generation by Source in Denmark in 2020 (GWh)**



Source: Danish Energy Agency[4]

The electricity access rate is 100 per cent. The electricity system of Denmark is separated into two areas. Western

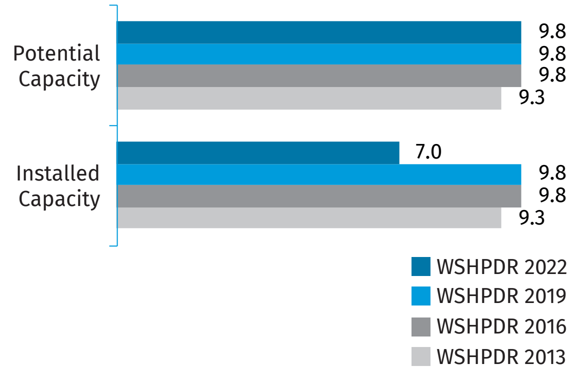
Denmark (DK1) is connected to the electricity system of Continental Europe through Germany and Eastern Denmark (DK2) is connected to the Nordic electricity system through Sweden and Norway. Any company can generate or distribute electricity in Denmark. The Danish Energy Agency acts as the overseeing body, responsible for granting authorizations to plants over 25 MW. The transmission system within the country is fully owned by Energinet. Transmission lines connect to Germany, Norway, Sweden and the Netherlands and are managed jointly by Energinet and the respective country's transmission company. Similar lines are planned to connect Denmark to the United Kingdom in the next few years.[5]

The electricity market of Denmark is integrated with Sweden and Norway though the Nord Pool power market, which coordinates trade in electricity as well as the spot and future markets between 20 countries. Prices in Norway and Sweden tend to be strongly influenced by rainfall due to the heavy reliance of these two countries on generation from hydropower. Final electricity prices for households are composed of approximately 39 per cent electricity prices, 41 per cent electricity taxes and 20 per cent value added taxes (VAT). In 2020, the electricity price for households was 2.11 DKK/kWh (0.30 USD/kWh).[4]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Denmark is up to 10 MW. In 2020, installed capacity of SHP was 7 MW that generated 16.7 GWh.[4] There have been three main hydropower plants in operation in Denmark: Tangeværket, Holstebro and Karlsgårdeværket, however, the Karlsgårdeværket plant was out of operation for restoration as of 2021.[6,7] The Tangeværket plant, built in 1921, is the largest with 3 MW installed.[8] Due to low elevations and slow flowing rivers, total potential in the country is 9.75 MW.[9] Given the flat nature of the country's terrain, further SHP development is unlikely. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, potential capacity remains unchanged and total installed capacity has decreased due to access to new data (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Denmark (MW)**



Sources: Danish Energy Agency,[4] *WSHPDR 2019*,[9] *WSHPDR 2016*,[10] *WSHPDR 2013*[11]

RENEWABLE ENERGY POLICY

Denmark has expressed commitments to expanding renewable energy for several decades. It was one of the very first countries to invest in wind power technology in the 1970s with government subsidies and subsequently introduced feed-in tariffs (FITs) and preferential prices shortly after. In the 1980s, the first renewable targets were set to have 1,000 MW of wind power by 2000, and once reached in 1999, the target was increased to 5,500 MW by 2030 which has already been reached.[12] Targets set in the 2012 Energy Policy included sourcing 70 per cent of electricity and 35 per cent final energy consumption from renewable energy by 2020, and 100 per cent renewable energy in final consumption by 2050.[13] The 2020 final energy consumption target has been reached with over 40 per cent in 2020, but the target for the electricity sector has fallen short.[4]

The Promotion of Renewable Energy Act passed in 2008 provides legal framework for the development of renewable energy, including SHP. It also provides a basis for FITs, which vary according to when the plant was connected to the grid and for how many years thereafter.[14]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The situation for SHP in Denmark has remained unchanged, for these main reasons:

- Potential capacity is small and has been almost fully developed;
- Residual flow requirements are judged individually for each project;
- Natural barriers and the flat nature of the country.[9]

Due to the lack of potential, there are no enabling factors to develop further traditional SHP. For further SHP development, unconventional technologies, such as in-conduit projects, could be considered.

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Estonia

International Center on Small Hydropower (ICSHP)

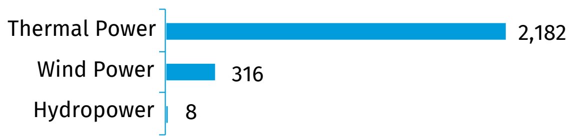
KEY FACTS

Population	1,329,479 (2020)[1]
Area	45,227 km² [2]
Topography	Estonia has a predominately flat terrain alternating between uplands and lowlands. The average elevation in the country is approximately 50 metres with only less than 10 per cent of the country reaching elevations above 90 metres. The western region of the mainland and islands off the west coast are mostly lowland plains, with some swampy plateau areas. The major upland areas include the Pandivere Uplands in the north-east, the Otepää Uplands in the central south-east region and the Haanja Uplands in the extreme south-east. The highest point in the country is Suur Munamägi Hill at 317 metres, situated in the Haanja Upland.[2,3]
Climate	Estonia has a humid, temperate climate in the transition zone between maritime and continental climates. The northern and western coastal areas typically have a milder, maritime climate than the southern interior's continental climate. The country experiences all four seasons of nearly equal length. Average temperatures in July vary between 16 °C and 17.4 °C, in which the warmer temperatures are at the coasts. The winters are also slightly warmer near the coasts, with average temperatures between −2 °C and −4 °C. Winters in the eastern uplands are colder with average temperatures closer to −7 °C.[2,3]
Climate Change	A major concern regarding climate change in Estonia is the rise in sea levels. Due to the country's extensive low-lying coastline, a sea level rise could cause severe flooding by the end of the century. Average temperatures have risen by more than 1 °C in the past century and are expected to continue warming, especially during the winter months. There has been a significant decrease in annual snow coverage, with an average of almost 26 less days of coverage per year than before the 1960s.[4]
Rain Pattern	The rate of precipitation in Estonia is much higher than that of evaporation, causing the country to have a very damp climate. Average rainfall varies between regions and seasons. February and March are the driest months throughout the country and July and August are the wettest. Annual rainfall is approximately 520 mm on the islands and coastal regions and 740 mm in the eastern uplands, with some parts experiencing over 1,000 mm. The average duration of snow coverage per year is approximately 109 days.[4]
Hydrology	Estonia has an extensive network of rivers and streams, though the large majority of them are small springs that seasonally dry up. The major drainage basins are the Gulf of Finland, the Gulf of Riga, Lake Peipsi and the western islands. The country's longest river is Pärnu at 145 kilometres flowing south-west from the Pandivere Uplands. The largest river by discharge is the Narva flowing northwards from Lake Peipsi. Other important rivers include the Emajõgi, Riisa, Kasari and Pirita. Some of these rivers have great seasonal variation in flow with large areas of flooding during spring. There are approximately 1,200 natural lakes, which combined cover almost 5 per cent of the country's territory. The majority of the lakes are located in the south-western upland region and the largest is Lake Peipsi with an area of 3,550 km² located along the western border with Russia.[2,3]

ELECTRICITY SECTOR OVERVIEW

In 2020, the total installed capacity in Estonia was 2,506 MW. The large majority was with thermal power, which includes both non-renewable and renewable sources, with 2,182 MW (87 per cent). The remaining 13 per cent was with 316 MW of wind power and 8 MW of hydropower (Figure 1).[5] There is also some solar power installed in the country, but an official value of total capacity is unavailable.[6] Thermal power capacity has been steadily decreasing since its peak of 2,807 MW in 2012, while wind power has been steadily increasing, but at a slower rate, during the same years.[5]

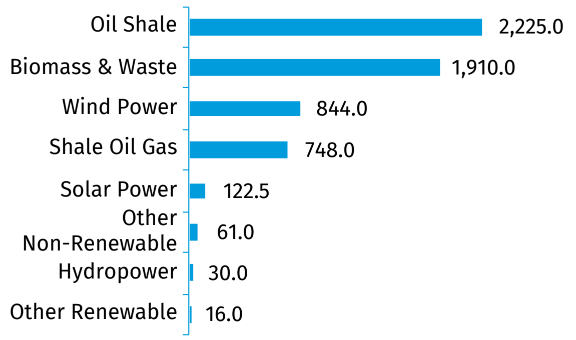
Figure 1. **Installed Electricity Capacity by Source in Estonia in 2020 (MW)**



Source: Statistics Estonia[5]

In 2020, total electricity generation was 5,956.5 GWh (Figure 2). Oil shale generated 2,225 GWh (37 per cent), biomass and waste 1,910 GWh (32 per cent), wind power 844 GWh (14 per cent), shale oil gas 748 GWh (13 per cent), solar power 122.5 GWh (2 per cent), hydropower 30 GWh (0.5 per cent), other renewable energy 16 GWh (0.03 per cent) and the remaining 2 per cent comprised other non-renewable energy which generated 61 GWh.[5] Estonia was net importer of electricity in 2020, having imported 7,367 GWh and exported 3,723 GWh. In the last few years, total electricity generation has been declining because of a sharp decrease in oil shale generation after 2018. The share of renewable energy in final energy consumption has been steadily increasing and was just over 30 per cent in 2020.[7]

Figure 2. **Annual Electricity Generation by Source in Estonia in 2020 (GWh)**



Source: Statistics Estonia[5]

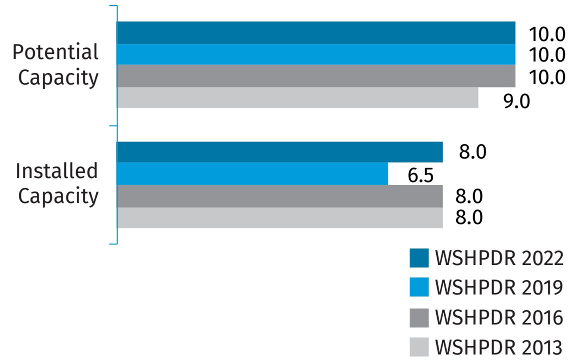
The electrification rate in Estonia is 100 per cent. The electricity sector has been liberalized since 2013, meaning that customers can choose their suppliers. While there are several privately-owned companies in the country, the supplier with the single largest market share continues to be the state-owned company, Eesti Energia AS.[8] Likewise, distribution is also liberalized but Elektrilevi, a subsidiary of Eesti Energia AS, holds approximately 95 per cent of the market share, recently acquiring the second largest distribution company in 2021.[9] Electricity transmission is fully operated by Elering. The transmission system has international interconnections with Finland and Latvia and is part of a synchronous area that also includes Lithuania. There is also transmission line infrastructure that remains in place between Estonia and Russia, but no trade of electricity has taken place between the two countries since 2005.[8,10]

In 2013, Estonia joined the Nord Pool market system, which determines the base price of electricity on the spot market. The Estonian Competition Authority approves the consumer prices in the country.[8] At the end of 2021, the electricity tariffs for industrial consumers ranged between 0.13 EUR/kWh (0.14 USD/kWh) and 0.19 EUR/kWh (0.20 USD/kWh), depending on usage, and tariffs for domestic consumers ranged between 0.16 EUR/kWh (0.17 USD/kWh) and 0.18 EUR/kWh (0.19 USD/kWh), depending on usage.[5]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Estonia is up to 10 MW. The installed capacity of SHP in Estonia in 2020 was 8 MW that generated a total of 30 GWh.[5] The total estimated potential capacity is approximately 10 MW, indicating that 80 per cent has been developed.[11] There are approximately 50, mostly privately owned, SHP plants, ranging from 4 kW to 1.2 MW, connected to the national grid.[12] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity has regained its prior level to 8 MW and the estimated potential has remained the same (Figure 3). The reason for the increase in installed capacity is not known.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Estonia (MW)**



Sources: Statistics Estonia,[5] *WSHPDR 2019*,[11] *WSHPDR 2016*,[13] *WSHPDR 2013*[14]

Estonia has a long history of hydropower, beginning with centuries-old water mills that were transformed into hydropower plants during the 19th and early 20th centuries. By 1940, there were over 900 sites in operation, ranging from simple waterwheels to modern turbines, with a combined capacity of 9.3 MW. However, almost all of these were destroyed during World War II and the rest were closed while the country was part of the Soviet Union. Starting from zero plants in 1990, hydropower capacity was steadily built back up until 2010 when it reached its current level of approximately 50 plants.[15]

There is 30 MW of overall theoretical hydropower potential in Estonia.[11] Due to the flat terrain and slow rivers, overall potential of hydropower in Estonia is low and hydropower is not considered an important renewable energy resource to develop much further. Nonetheless, there is a considerable number of old water mill sites that could potentially be modernized and incorporated into the grid, as long as they are not located in a protected river and would comply with new environmental standards. A number of standards that aim to protect fish migration and the natural ecosystems of waterways have been enforced in recent years. This includes 125 rivers throughout the country that have been legally protected against any dam construction within them. The Narva River, the country's largest by discharge, does not appear on the list of protected rivers, which opens up the possibility for large hydropower to be developed, however, with strict regulations on dam construction and the lack of importance put on hydropower in general, development of such potential is unlikely.[15]

RENEWABLE ENERGY POLICY

As a member of the European Union, Estonia has prioritized increasing the share of renewable energy in both production and consumption in order to reduce environmental pollution and cut greenhouse gas emissions. In compliance with the European Union Renewable Energy Directive (2009/28/EC), the Government of Estonia published its National Renewable Energy Action Plan in 2010. This plan set targets such as for 1,913 GWh of electricity to be generated with renewable energy sources as well as 30 per cent of final consumption by 2020.[16] Both targets were reached, although by different means than those of the original plan, which expected wind power to have a much higher importance in the energy mix and for biomass to be slightly lower. The National Energy and Climate Plan for 2030, with the final version published in 2019, provided a set of goals for the following decade. By 2030, the country intends for 4,300 GWh of electricity to be generated by renewable energy along with 42 per cent of final energy consumption. According to this plan, hydropower generation and installed capacity are expected to remain at their current levels of 30 GWh and 8 MW, respectively, to 2030, and the overall increase is planned to come mostly from wind power, but also some solar power and biomass.[17]

In Estonia, energy production from renewable energy sources has been mainly promoted through subsidies and more recently, reverse auctions. As stated in 2009 amendments to the Electricity Market Act, the national transmission company is to provide subsidies to renewable energy producers under 100 MW. This includes electricity generated from any type of renewable source as well as cogeneration of heat and power (CHP) using biomass.[18] The financing costs of the subsidy is passed on to consumers in the form of a renewable energy charge relative to consumption. Elering announces the costs each year, and for 2021 it was 0.0136 EUR/kWh (0.014 USD/kWh).[19] As of 2019, these subsidies had begun phasing out to be replaced by reverse auctions. The first reverse auction took place in 2019 and will take place annually.[20]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key barriers to SHP development in Estonia include:

- Low overall potential due to flat terrain;
- Residual flow values are fixed in the water use licensing procedure and are set on the 95 per cent fraction of the flow duration curve;
- Fish pathways are often requested, making projects more expensive.

The key enabler for SHP development in Estonia is:

- Numerous old water mill sites could be assessed to be transformed and made operational again.

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Finland

Kristian Dahl Larsen, Samfunnsbedriftene Energy

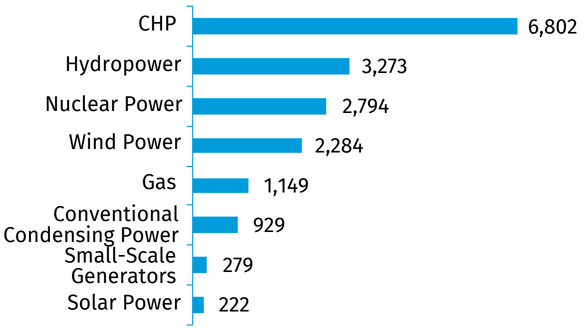
KEY FACTS

Population	5,533,793 (2021)[1]
Area	338 462 km^2 [2]
Topography	The topography of Finland is largely flat land with almost 70 per cent of the area covered by forest, while numerous lakes occupy a large part of the remaining area. While the southern regions terrain is dominated by lakes and flatland, low hills and mountains characterize the northern region. The highest mountain, Haltitunturi (1,328 metres) is located in the north-western tip of Finland, on the border with Norway.[3,4]
Climate	The average annual temperature is approximately 5.5 °C in the south and somewhat lower towards the north. Temperatures differ between seasons and regions. The average difference between the southern and northern regions is greatest in winter, when the difference can reach up to 12 °C. The recorded average high temperature was 31.8 °C, while the low temperature was estimated at 39.9 °C.[5,6]
Climate Change	The climate is defined by major yearly variation, although the longer climate trend shows more persistent changes. Annual average temperature has increased by over 2 °C since the 1850s and is forecasted to continue to rise. Depending on the level of global greenhouse emissions, climate models predict that average temperature in Finland could increase by between 2.6 °C and 8.5 °C before the end of the century. As a result of the higher annual temperature, precipitation is estimated to increase and intensify further. Estimations of annual precipitation predict an increase of between 6 and 11 per cent by 2050 and of up to 20 per cent by 2100. Extreme rainfall events are estimated to increase significantly, highest runoffs to turn from spring to winter and risk of frazil ice formation to increase in many rivers due to shorter time of ice cover.[7,8,9]
Rain Pattern	Average annual precipitation ranges from 500 mm to 650 mm. Rain patterns are infrequent and created by swift temperature changes. Summer periods record more regularity in showers and thunderstorms. The precipitation varies between the different regions and seasons. In the southern and central regions, annual precipitation is between 600 mm and 700 mm, while in the northern region and along the coast annual precipitation is lower. The long winter causes approximately half of the annual 500–600 mm of precipitation in the north to fall as snow. The lowest recorded annual precipitation is 200–300 mm and highest annual precipitation recorded is 900–1,100 mm. Spring is categorized as the lowest annual season for precipitation, where March is considered the month with the least precipitation of the season. Precipitation slowly increases following spring and levels out in the summer months of July–August, then decreases gradually towards winter and spring.[5]
Hydrology	Finland has large water resources in its many lakes and rivers. Inland water covers almost 10 per cent of the country's area. The largest lake, Saimaa, stretches over 4,400 km^2. Lake Saimaa forms a lake system that connects over 120 other rivers and lakes. Several hydropower plants are located along the lake system. Many of the rivers flow into the inland lakes. The major rivers in the country are Kemijoki, Tornion-Muonionjoki, Oulujoki, Teno, Vuoksi, Kymijoki and Kokemäenjoki. Kemi is the longest river, stretching almost 550 kilometres.[4,10]

ELECTRICITY SECTOR OVERVIEW

The electricity produced in Finland mainly comes from nuclear power, combined heat and power (CHP), hydropower and wind power.[11] In 2019, Finland produced 66,043 GWh domestically.[12] Of the total domestic production, nuclear power accounted for 22,915 GWh, hydropower for 12,239 GWh and wind power for 6,025 GWh. Conventional condensing power accounted for 3,147 GWh, while CHP from industry, district heating and small-scale generation together accounted for 21,576 GWh (Figure 1). Wind and solar power continued to ramp up to become a bigger part of the country's power generation. From 2016 to 2019 electricity generation from solar power increased by more than five times. However, the overall contribution in 2019 was a mere 0.2 per cent of the country's supply.[11] The role of wind power has also developed quickly in Finland. In 2019, electricity generation from wind power almost doubled from 2016.[13] In the same year, wind power made up almost 9 per cent of the total electricity production in Finland, up from less than 5 per cent in 2016. Hydropower generation declined from 2016 levels, but shows some historic variance and previous production on similar levels as in 2019.[11] The share of hydropower will naturally vary due to weather fluctuations and water supply in a given year.[14]

Figure 1. **Annual Electricity Generation by Source in Finland in 2019 (GWh)**

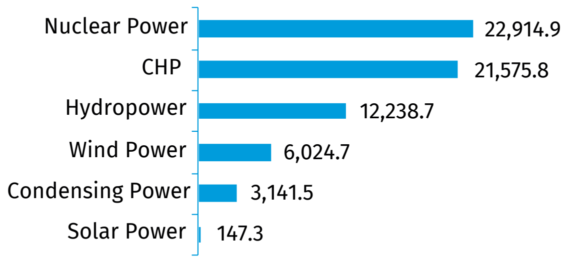


Source: Statistics Finland[11]

Electricity imports also play an important part in the country's supply and amounted to approximately 22,000 GWh in 2020.[12] The majority of electricity imports came from Sweden, while the majority of exports went to Estonia.[15]

In terms of capacity, total installed capacity of Finland amounted to 17,732 MW in 2020. Largest installed capacity was found from CHP (district heating and industry) with 6,802 MW, while hydropower had 3,273 MW of installed capacity, nuclear power 2,794 MW, wind power 2,284 MW and gas-powered plants 1,149 MW (Figure 2).[13]

Figure 2. **Installed Electricity Capacity by Source in Finland in 2020 (MW)**



Source: Statistics Finland[13]

The electricity market in Finland was deregulated and open to competition with the Electricity Market Act in 1995. The act led to changes such as freedom for customers to choose their electricity supplier. Private households can today produce their own electricity and sell it to the market.[16] The electricity market has several players, although Fortum remains the largest by far.[17] Fortum is a publicly traded company, although the majority shareholder with over 50 per cent remains the Finnish state.[18] Additionally, Finland is part of the Nordic wholesale electricity market, where electricity is traded freely across bidding zones in the Nordic and Baltic countries.[19] Finland currently has one bidding zone.[20]

In terms of prices and tariffs Finland is competitive compared to its European peers. In the second half of 2020, household prices constituted EUR 0.177 (USD 0.20) (including taxes) per kWh, which ranked in the middle among the European Union (EU) member states.[12] The same ranking of electricity prices for industry shows a price of EUR 0.094 (USD 0.11) per kWh, which is the second lowest among the EU27.[12] The transmission grid of Finland is also highly competitive in terms of pricing. A recent study found the main grid tariff to be the second cheapest among the EU members, only beaten by Slovenia.[21]

Finland has a well-developed electricity system and has enjoyed an overall 100 per cent electrification rate for the total population since before 1990.[22] In Finland, there is three grid levels: high voltage, medium voltage and low voltage.[23] High-voltage networks (110–400 kV) measure approximately 22,500 kilometres long.[23] The medium-voltage (1–70 kV) networks reach over 150,000 kilometres, while the low-voltage network (up to 1 kV) expands over 250,000 kilometres.[24] To further develop and upgrade the grid, the Finnish transmission system operator (TSO), Fingrid, has plans to invest EUR 1,200 million in the grid between 2015 and 2025.[25] Fingrid has set a target to build 3,000 kilometres of new transmission lines in that period.[25] Furthermore, the Swedish TSO Svenska Kraftnät and Fingrid are planning to develop an 800 MW alternating current connection between the northern regions of the two countries. The connection is to be finished by 2025.[26]

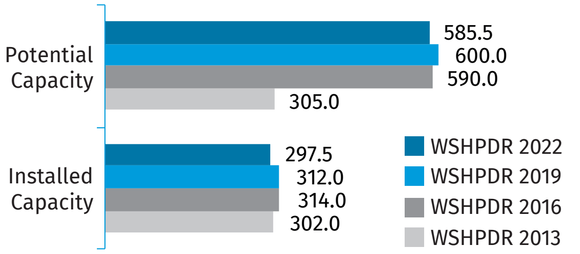
The regulator in Finland, Energiavirasto, is a licensing and supervisory body that monitors the operations and implementation of the electricity markets.[27] In addition, an important role of the regulator is to regulate monopoly situations of the transmission companies.[28] As the licence-providing body, Energiavirasto also maintains a register of power plants exceeding 1 MVA.[17]

The Government of Finland has set in motion plans for developing the electricity sector to decrease import dependencies. For instance, Finland is currently building two new nuclear power plants to replace electricity imports.[26] The Government also introduced feed-in tariff (FIT) subsidy schemes to increase renewable energy. The scheme applied to wind power, biogas, forest chips and wood-based fuels (not hydropower) starting from 2010, but has been discounted since 2021.[29]

SMALL HYDROPOWER SECTOR OVERVIEW

Finland defines small hydropower (SHP) as plants of up to 10 MW in capacity. The regulator, Energiavirasto, publishes an official registry of the power plants in Finland.[21] According to the data of 2021, the installed capacity of SHP plants in Finland was approximately 297.5 MW from approximately 80 power plants.[21] Approximately 120 MW of small-scale plants was connected to the grid in 2015, which suggests that many SHP plants are decentralized (Table 1).[30] The installed capacity in 2021 was approximately 5 per cent lower than the installed capacity reported in the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 3). The decrease in capacity could be due to the refurbishment done in the three-year period, which could have brought some power plants above the 10 MW threshold. Another possibility is the discontinuation of operation of some plants. The trend of discontinuation of SHP operation has increased in recent years.[31] State support for the decommissioning of SHP plants is both available and promoted through the national NOUSU programme, which aims to slow down the loss of biodiversity by removing barriers for fish migration.[32] Notably, sentiment towards new hydropower in Europe has decreased in recent years, mostly driven by environmental groups focused on improving and restoring the biodiversity of rivers.[33]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Finland (MW)**



Source: Energiavirasto,[21] Motiva,[31] *WSHPDR 2013*,[34] *WSHPDR 2016*,[35] *WSHPDR 2019*[36]

According to Motiva, a state-owned sustainable development company, the undeveloped potential of SHP in Finland is estimated to be approximately 288 MW and the total undeveloped potential of all hydropower is estimated to be 663 MW.[31] A significant part of the undeveloped potential is found by the modernization and capacity upgrades of old plants.[37] Combined with the current installed capacity, total potential capacity of SHP can therefore be estimated to be close to 585.5 MW. It is worth noting that the undeveloped potential does not take into account protected waters or border rivers.[30] Furthermore, the Finnish authorities report that no new SHP initiatives are planned in the near future, seeing as the majority of undeveloped potential is not from new sites but rather from repowering of existing sites.

Table 1. **List of Selected Operational Small Hydropower Plants in Finland**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Maavesi	Joroinen, Katajamäentie 1461, Maavesi	2.0	Savon Voima Oyj	2021
Korkeakoski	Korkeakosken voimalaitos Kotka	10.0	Kolsin Vesivoimantuotanto Oy	2016
Myllykosken vesivoimalaitos 1	Myllykosken vesivoimalaitos 1	6.9	Pato Osakeyhtiö	2012
Koivukoski	Koivukosken voimalaitos Kotka	1.8	Kolsin Vesivoimantuotanto Oy	2001
Liunankoski	Joroinen, Liunantie 79	1.2	Savon Voima Oyj	1995
Juankoski	Juankoski, Juankoskentie 7A	5.5	Savon Voima Oyj	1995
Vääräkoski	Tohmajärvi, Vääräkoski	1.8	Pohjois-Karjalan Sähkö Oy	1992
Tammerkoski	Tammerkoski	8.6	Tampereen Sähkölaitos	1992
Kuokkastenkoski	Nurmes, Kuokkastenkoski	2.0	Pohjois-Karjalan Sähkö Oy	1990
Sälevä	Lapinlahti, Itäkoskentie 53, Paloinen	3.0	Savon Voima Oyj	1988
Sallila	Sallila (Vampulan kunnassa)	1.2	Sallila Energia Oy	1986
Långfors	Långfors	1.2	Oy HERRFORS Ab	1985
Saario	Tohmajärvi, Saario	1.6	Pohjois-Karjalan Sähkö Oy	1984
Hamari	Hamari, Ylivieska	2.5	Korpelan Voima kuntayhtymä	1984
Stadsforsens Kraftverk	Stadsforsens Kraftverk	4.6	Nykarleby Kraftverk	1984
Klåsarö	Klåsarö	4.5	Oy Mankala Ab	1983
Kiltua	Sonkajärvi, Kiltuantie 1129 A, Jyrkkä	5.6	Savon Voima Oyj	1982

Source: Energiavirasto[21]

RENEWABLE ENERGY POLICY

The National Energy and Climate Plan (NECP) outlines the country's climate and energy goals in the future and supports the overall targets of the EU. According to the NECP, the Government aims to reduce emissions in non-ETS (Emissions Trading System) by 39 per cent by 2030.[26] To add to the ambition, the Government has set a goal to be carbon-neutral by 2035.[38] Moreover, the plan sets a national renewable energy target of 51 per cent in gross final energy consumption by 2030.[26] The target of Finland is part of its contribution to the binding renewable target for the EU of 32 per cent by 2030. This target was proposed to be increased to 40 per cent by the European Commission in July 2021.[39] This could indicate that Finland will need to revise the national renewable target in the coming years.

Bioenergy plays an important role in renewable energy production in Finland, due to the vast and rich forest resources in the country.[26] According to the International Energy Agency (IEA), biofuels and waste contribute over 50 per cent of total domestic energy production.[40] This share continues to increase. Nuclear power is the second most dominant source, while hydropower and wind power account for a lesser share.[40]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Hydropower is heavily regulated in both Finland and the EU. In Finland, the Water Act (587/2011) is very important for hydropower because permits for the construction and operation of a plant are issued in accordance with the act.[41,42] In 2019, the Government made plans to update the Water Act and extend the tight regulations for fisheries, which toughens the environmental regulations for SHP plants and limits profitability.[31]

Several other domestic legislations are also essential for SHP in Finland. For instance, it is necessary to comply with the Act on the Protection of Rapids (35/1987) to build a hydropower plant. Furthermore, an environmental impact assessment (EIA) according to the Environmental Impact Assessment Procedure Act (468/1994) must be performed where hydropower is planned.[43,44] In addition, it is necessary to comply with the Nature Conservation Act (1096/1996), which constitutes the framework for biodiversity and sustainable use of natural resources, and the Environmental Protection Act (579/2014), which regulates environmental pollution.[45,46] On the EU level, the EU Water Framework Directive (2000/60/EC) sets the overall framework for hydropower regulation for member states.[47]

COST OF SMALL HYDROPOWER DEVELOPMENT

The cost of SHP projects depends largely on their type, size and location.[48] Therefore, many hydropower plants have a location-specific cost. Generally, the cost allocation of SHP plants is divided somewhat differently than for large plants.[50] For instance, the IEA estimates that civil works account for a smaller cost share for SHP, while the cost share of electrical and mechanical equipment is larger than for large plants.[50] Some of the main economic barriers for SHP are high investment and audit costs, but electricity transmission prices and tax also dampen profitability.[30] The latter could explain why many small-scale plants choose to stay disconnected from the grid. According to the state-owned sustainable development company, Motiva, one reason why construction of SHP plants is predicted to slow down is heavy labour cost and poor economics.[31]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Finland has previously had several support schemes for renewable energy. For instance, production support, such as FITs, for certain renewable energy sources, including wind power, biogas, wood fuel and wood chips, have been available.[29] The FIT system has decreased over time and finally closed in March 2021.[29] Another tender scheme called “Bonus system” was introduced in 2018.[42] The Bonus system is a technology-neutral subsidy scheme for up to 12 years.[42] Green certificates or Guarantees of Origin are available for all renewable energy producers of electricity and would serve as additional revenues for the producers.[49] No new support schemes for renewable energy production appear to be planned in Finland.[29]

Energy support can also be granted in the form of investment support, specifically for small-scale renewable production, new technologies and research projects.[50] However, SHP is excluded from the investment aid scheme.[42] In recent years, the trend has moved towards discontinuing SHP because of more stringent environmental policy due to biodiversity impacts and state support for the decommissioning of SHP plants has rather been made available.[32]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Temperature in Finland has risen by almost 2 degrees since the 1850s and is estimated to increase further if greenhouse gas emissions continue to increase.[8] A higher temperature will lead to more annual precipitation as well as more intensified and extreme episodes of rainfall.[9] Thus, increased temperatures from climate change could improve profitability for SHP due to the increased and more intensive rainfall. However, the ability to utilize the increased precipitation depends on the location of the additional rainfall and the available capacity of nearby SHP plants. Other effects of a warmer climate contribute to less snow accumulation in winter, leading to less snow melting in spring and therefore smaller capacity factors for hydropower.[51] In addition, the risk of frazil ice formations—ice that does not float—increases due to thinner ice cover and could lead to clogging of the water intake for SHP plants. Reduced water from snow melting and increased risk of clogging could have strong negative effects on the business case of SHP plants. However, estimates of the amount of reduced snow in Finland vary largely and depend on global emission reductions in the coming years.[51]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The following points summarize the main barriers to SHP development in Finland that have been identified:

- Heavy regulatory framework for hydropower plants;

- Government policies prioritize biodiversity concerns such as rehabilitation of watersheds and fish migration more than adding new SHP capacity;
- Limited profitability for new SHP projects and few financial support incentives available for SHP;
- Reduced water from snow melting and increased risk of frazil ice formations as a result of a warmer climate.

The following points summarize the main enablers that have been identified:

- Rich water resources available;
- Precipitation estimated to increase and intensify due to increased temperatures from climate change.

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Iceland

Kristian Dahl Larsen, Samfunnsbedriftene Energy

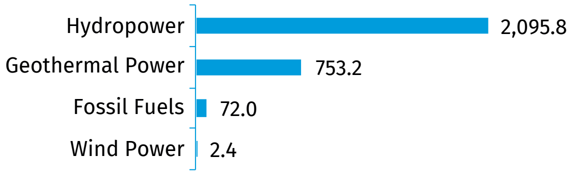
KEY FACTS

Population	368,792 (2021)[1]
Area	103,000 km^2 [2]
Topography	Iceland is a volcanic island containing over 200 volcanoes, with glaciers and cold lava covering roughly 10 per cent of the country's land area. The elevation differs largely. The highest point in Iceland is the top called Hvannadalshnjúkur, which rises to 2,199 metres above sea level. The average elevation of the land is approximately 500 metres above sea level, yet one quarter of the land is below 200 metres above sea level.[3,4]
Climate	The weather in Iceland is mild coastal despite the northern location, largely because of the Gulf Stream. Average temperatures in summer are approximately 10 °C and can reach highs of 24 °C. Average winter temperatures are approximately 0 °C. In general, the weather can be unstable and change quickly.[3]
Climate Change	Climate change will likely have a large impact on the island country of Iceland, most notably because of the melting of glaciers in the country. Estimates by the national meteorological institute suggest that all glaciers might vanish in the next 100–200 years. This will have major impacts on the marine ecosystem because of the acidification of the ocean. However, the melting of glaciers could also create new lakes or add to the capacity of existing ones. Estimates from climate models suggest the temperature could increase by approximately 1.3-2.1 °C by 2050. Similarly, precipitation is estimated to increase by 1.2–4.3 per cent by the middle of the century.5
Rain Pattern	Average precipitation varies largely depending on the region of the country. In the south of Iceland, annual precipitation is estimated at approximately 5,000 mm, while in the mountainous areas it ranges between 1,000 mm and 3,000 mm and in the northern part is as low as 1,000 mm. Precipitation is greatest during the winter months (December–January) and lowest in the summer months (May–June). The difference can also be rather large, where precipitation in winter months can be twice the monthly average of summer months. The Icelandic regulator estimates the energy flow from precipitation to be approximately 220–285 TWh annually.[5,6]
Hydrology	Iceland has access to several good water sources through many lakes and waterfalls, numerous rivers, large glaciers and heavy rainfall. The main rivers are Pjorsa, Jokulsa a Fjollum, Olfussa, Jokulsa a Bru, Lagarfljot, Skjalfandafljot, Skeidara and Kudafljot. Pjorsa is the longest river stretching approximately 237 km in length.[4]

ELECTRICITY SECTOR OVERVIEW

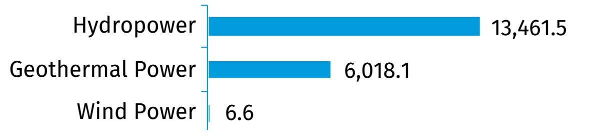
In 2019, Iceland generated a total of 19,489 GWh of electricity from hydropower, geothermal power, wind power and fossil fuels.[7] Of the total production, hydropower contributed 13,461.5 GWh, while geothermal power produced 6,018.1 GWh. Wind power and fossil fuels accounted for 6.6 GWh and 2.7 GWh, respectively (Figure 1).[7] In the same year, total installed capacity reached 2,923 MW.[7] This represents an increase of approximately 157 MW from 2017.[8] In terms of installed capacity, over 71 per cent of the total was from hydropower, while geothermal power was the second largest source (Figure 2). Access to electricity in the country is 100 per cent in both rural and urban areas.[9] In fact, the electrification rate in Iceland has been 100 per cent since the 1990s, according to the World Bank.[9]

Figure 1. **Annual Electricity Generation by Source in Iceland in 2019 (GWh)**



Source: Orkustofnun[7]

Figure 2. **Installed Electricity Capacity by Source in Iceland in 2019 (MW)**



Source: Orkustofnun[7]

With nearly 100 per cent of electricity coming from renewable sources, Iceland is a world leader in clean electricity production. In addition, Iceland tops the list of per capita energy production producing 53,832 kWh per person annually.[10] The heavy industry plays an important part in the country's electricity sector as it makes up much of the electricity demand. In 2018, this share was 81 per cent.[11]

In 2003, a new electricity act was introduced for the electricity sector in Iceland. The act was significant in that it separated production and sale of electricity transmission and distribution. The aim of the law was to introduce more competition in the sectors of electricity production and sale, mirroring the model used in the European Union.[12] The national regulator, Orkustofnun, was given the power to supervise the implementation of the act.[13] Additionally, as Orkustofnun is responsible for issuing licences for new power plants, monitoring compliance of the licensed plants and overseeing tariff calculations of the income cap for distribution and transmission companies.[14] The major electricity producers in Iceland are Landsvirkjun, Orka náttúrunnar and HS Orka. Landsvirkjun is by far the largest of the producers, responsible for approximately 71 per cent of total electricity production, while Orka náttúrunnar and HS Orka produce 19 and 7 per cent, respectivly.[12] The public sector has a strong presence in the electricity sector of Iceland. Most of the large power producers are either owned directly by the state or by municipalities, with the one exception being HS Orka.[15] For instance, Landsvirkjun is 100 per cent owned by the state, while Orka náttúrunnar is owned by several municipalities.[16,17]

The main grid is operated by the Icelandic transmission system operator (TSO), Landsnet.[12] The grid is comprehensive with over 75 substations, 85 delivery points for power plants and large users and 59 delivery points for distribution utilities.[18] Additionally, the gird consists of more than 3,000 kilometres of transmission lines.[19] The majority of the grid is overhead, while only a small part in urban areas is laid underground.[18] According to the TSO, the grid is constantly upgraded and expanded to keep up with the growing demand.[18]

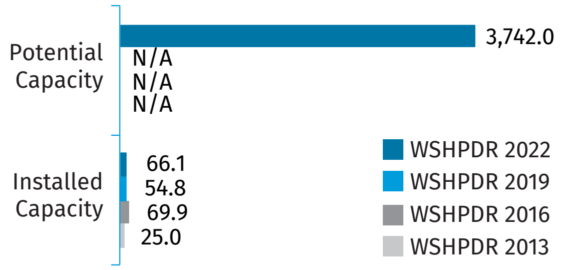
The electricity market of Iceland is highly liberalized, heavily based on renewable generation, although with no integration or interconnectors to other power systems.[14] Overall, Iceland enjoys very competitive electricity prices compared to other Northern European countries.[20] However, since there is no power exchange in Iceland, over 80 per cent of energy sold to large consumers is done through power purchase agreements (PPAs).[14]

The average price of electricity for households increased by 8.7 per cent since January 2021, reaching 0.1356 EUR/kWh (0.15 USD). The price excluding taxes was 0.1071 EUR/kWh (0.12 USD).[21]

SMALL HYDROPOWER SECTOR OVERVIEW

In Iceland, small hydropower (SHP) plants are defined as hydropower plants of up to 10 MW. According to the register of the regulator Orkustofnun, existing SHP plants produced 332.2 GWh of electricity in 2019 and had a total installed capacity of 66.1 MW.[7] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, this indicates a 21 per cent increase in capacity (Figure 3), which could be due to new projects coming online, as Iceland is pushing for innovation to build and utilize more SHP in rural areas. In addition, several power plant licences have been issued for SHP in Iceland in recent years.[22] From 2018 to 2021, at least seven licences for SHP were issued, indicating that the SHP sector in Iceland is in continuous development.[23] A list of selected existing SHP plants is displayed in Table 1.[7]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Iceland (MW)**



Source: Orkustofnun,[7,26,27,28,29,30] *WSHPDR 2013*,[31] *WSHPDR 2016*,[32] *WSHPDR 2019*[33]

In terms of grid connectivity, the Government has decided that power plants larger than 1 MW must be connected to the grid.[24] As in most of Europe, some public resistance towards new hydropower exists in Iceland, which is exemplified by the environmental group Save Þjórsá River.[25]

Table 1. **List of Selected Operational Small Hydropower Plants in Iceland**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Setbergsvirkjun	Setbergsvirkjun	0.04	Smávirkjun	2019
Hólsvirkjun	Hólsvirkjun	5.50	Smávirkjun	2019

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Úlfsárvirkjun	Úlfsárvirkjun	0.20	Smávirkjun	2019
Bugavirkjun	Bugavirkjun	0.04	Smávirkjun	2014
Glerárvirkjun II	Glerárvirkjun II	3.30	Fallorka	2018
Urðarfells-virkjun	Urðarfellsvirkjun	1.15	Smávirkjun	2018
Þverárvirkjun - Önundarfirði	Þverárvirkjun - Önundarfirði	0.40	Smávirkjun	2018
Köldukvíslar-virkjun	Köldukvíslar-virkjun	2.79	Smávirkjun	2013
Gúlsvirkjun	Gúlsvirkjun	3.40	Smávirkjun	2009
Bjólfsvirkjun	Bjólfsvirkjun	6.40	Smávirkjun	2008
Djúpadals-virkjun I/II	Djúpadalsvirkjun I/II	2.80	Fallorka	2004/2006
Múlavirkjun	Múlavirkjun	3.10	Smávirkjun	2005
Gönguskarðsá	Gönguskarðsá	1.80	Smávirkjun	2015
Árteigsvirkjun	Árteigsvirkjun	1.22	Smávirkjun	2005/2009
Þverárvirkjun	Þverárvirkjun	2.20	Orkubú Vestfjarða	1953
Grímsá	Grímsá	2.80	Orkusalan	1958
Skeiðfoss	Skeiðfoss	4.80	Orkusalan	1945
Andakíll	Andakíll	8.20	Orka Náttúrunnar	1947

Source: Orkustofnun[7]

The maximum theoretical potential of SHP has been estimated using geospatial water catchment and stream flow analysis. An analysis was conducted for each of the five main regions of the country (Table 2). This represents an enormous potential compared to the current installed capacity. However, it remains to be seen how much of this potential is technically and economically feasible.

Table 2. **Summary of Theoretical Potential of Small Hydropower by Region in Iceland**

	Eastfjords	*Northland*	*Westfjords*	*West Iceland*	*South Iceland*	*Total*
Number of sites	883	532	401	246	444	2,506
Potential capacity (MW)	1,603	829	447	215	648	3,742

Source: Orkustofnun[26,27,28,29,30]

Planning applications can be viewed on the Orkustofnun website, and the known SHP projects in planning are displayed in Table 3.[23] Table 4 shows selected SHP projects available for investment.[34]

Table 3. **List of Known Planned Small Hydropower Projects in Iceland**

Name	*Location*	*Capacity (MW)*	*Developer*	*Stage of Development*
Þjóðbrókargil	Strandabyggð	9.9	N/A	Exploration licence issued in 2021
Hólsvirkjun	Fnjóskadalur	5.5	Arctic Hydro ehf.	Licence to build and operate issued in 2019
Eyjafjarðarsveit	Eyjafjarðará	1.0	Tjarnavirkjun ehf.	Power plant licence issued in 2019
Köldukvíslar	Austur Hérað	2.0	Orkusalan ehf.	Exploration permit issued in 2018
Ódáðavötn	Fljótsdalshérað	4.0	Orkusalan ehf.	Exploration permit issued in 2018
Úlfsárvirkjun	Dagverðardalur	0.2	AB-Fasteignir ehf.	License to build and operate issued in 2018
Gilsár	Hérað	2.0–3.0	Orkusalan ehf.	Exploration permit issued in 2018

Source: Orkustofnun[23]

Table 4. **List of Selected Small Hydropower Projects Available for Investment in Iceland**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/refurbishment)*
Fitjá-neðri	Húnaþing Vestra	2.9	207	New
Fitjá-efrI	Húnaþing Vestra	1.8	180	New
Gilljá	Húnavatnshreppur	1.8	190	New
Vatnsdalsá	Húnavatnshreppur	5.6	95	New
Álftaskálará-neðri	Húnavatnshreppur	5.4	230	New

Source: SSNV & Mannvit[34]

RENEWABLE ENERGY POLICY

In its Climate Action Plan, Iceland states the aims to reduce its emissions by at least 40 per cent by 2030 and reach carbon neutrality by 2050.[35] Due to the low carbon intensity of electricity production in Iceland, much of the attention to further reduce emissions is given to road transport, agriculture, fisheries and waste management, on the one hand, and to carbon sequestration through afforestation and land restoration, on the other hand.[36] In general, new renewable power plants are regulated through the Master Plan for Nature Protection and Energy Utilization, which sets a framework to reconcile competing interests in regards to the use of natural resources.[37] Options for power plants are to be evaluated by a committee in each phase, categorized by vote in the Parliament. The Master Plan is currently in its fourth phase, but has been halted for some years due to the unfinished Parliament resolution of the third phase.[38]

In late 2016, Orkustofnun presented the idea of a small power plant project. The project aims to incentivize power production in rural areas to help with the national security of supply issues.[39] The concern over the security of supply originates from a number of factors, including an increase in electricity consumption from a growing population, the halted Master Plan with few new power projects and the large cost and time of building a new grid.[39] One key aspect of the project is to map suitable possibilities for new SHP production. A grant for Master's degree research in SHP is offered.[40] However, SHP plants must compete on the open market for sale and production of electricity as other actors.[39]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

In Iceland, the national regulator is responsible for granting licences for new power plants, however, power plants with an installed capacity below 1 MW do not need a permit unless the electricity will be delivered to the grid.[41] In addition, hydropower plants must comply with two main pieces of legislation, namely the Water Law of 1923 and the Act on Exploration and Utilization of Ground Resources of 1998.[42,43]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

There are several financial mechanisms available for SHP projects. All producers of electricity from renewable energy sources are eligible to receive green certificates or Guarantees of Origin (GOs) from the TSO, Landsnet.[44] These certificates can be traded on the market and contribute as additional revenue for power plants. In addition, Iceland distributes grants and loans through its Energy Fund for projects that utilize renewable energy sources and reduce the use of fossil fuels.[45] Furthermore, SHP plants are eligible for green loans, which enjoy benefits such as lower interest rates and a possibility of interest payment only for the first three years.[46] Grants for the study and research of SHP are also available.[40]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change is expected to have a significant effect on Iceland and SHP development most notably in terms of increased precipitation and melting of glaciers.[5] The glacier melting is estimated to happen over the next 100–200 years.[5] The national regulator estimated that the country's glaciers hold significant amounts of energy, of up to 7,600 TWh, that will be released.[6] Not all the melted glacier water can be utilized due to the distribution and localization of the existing hydropower plants; however, SHP can be built to optimize the water resources from the new streams.[6]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The following points summarize the main barriers to SHP development in Iceland that have been identified:

- Some public resistance, particularly from environmental groups, towards more hydropower development;
- Uncertainty over the amount of SHP potential that is technically and economically exploitable.

The following points summarize the main enablers that have been identified:

- Strong determination from the Government to research and utilize more SHP. Examples include financial mechanisms, increased research and mapping of SHP opportunities from the regulator;
- Comprehensive legislative framework for hydropower compared to wind and solar power.
- Increased predicted precipitation as an effect of climate change is expected to create strong business opportunities for SHP projects;
- Growing electricity demand from an increasing population offers an opportunity for SHP, especially due to the limited gird capacity available for supply from other major power plants.

Disclaimer: The opinions, statistical data and estimates contained in this chapter are the responsibility of the author and should not be considered as reflecting those of the author's affiliated organization. By extension, the author's affiliated organization is not liable for the information or the views presented in this chapter.

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Republic of Ireland

Tamsyn Lonsdale-Smith, International Center on Small Hydro Power (ICSHP)

KEY FACTS

Population	5,011,500 (2021)[1]
Area	70,290 km^2 [2]
Topography	The country's terrain has been described as bowl-shaped, with low-lying interior plains surrounded by rugged hills and low mountains and with sea cliffs on the west coast. The mean elevation is 118 metres, while the highest point is Carrauntoohil at 1,041 metres in the Macgillycuddy's Reeks situated in the south-west. Other key mountain ranges include: the northern Blue Stack Mountains, the eastern Wicklow Mountains (which house the Lugnaquillia at 926 metres), the southern Knockmealdown and Comeragh mountains and the western Twelve Pins. The lowest point is North Slob in County Wexford, at 4 metres below sea level.[3]
Climate	The climate is maritime temperate, modified by the warm North Atlantic Drift, particularly on the Atlantic coast, and by the prevailing south-westerly Atlantic winds. The climate is humid, yet the hills and mountains, many of which are near the coast, provide shelter from strong winds and from direct oceanic influence. Winters are cool and windy. From February to June, there is less rainfall due to continental anticyclones. Temperatures can range from 2 °C to 10 °C in the winter months and from 10 °C to 20 °C in the summer months, depending on the region.[4,5]
Climate Change	The average annual surface air temperature in Ireland has increased by over 0.9 °C over the last 120 years, with a rise in temperatures being observed in all seasons. Annual precipitation was 6 per cent higher in the period from 1989 to 2018, compared to the 30-year period from 1961 to 1990. Sea level rise and higher oceanic temperatures have also been observed in the ocean and coastal areas. By mid-century, Ireland could see increased frequency of heavy rainfall events, while annual precipitation is expected to decrease overall, by 1–3 per cent in the medium-to-low scenario and by 3–20 per cent under the high emission scenario.[6]
Rain Pattern	Most of the eastern half of the country receives between 750 mm and 1,000 mm of rainfall per year. Rainfall in the west generally averages between 1,000 mm and 1,400 mm. In many mountainous districts, rainfall exceeds 2,000 mm per year. The wettest months in almost all areas are December and January. April is generally the driest month across the country. However, in many southern regions, June is the driest.[4,5]
Hydrology	There are over 70,000 km of waterways made up of 3,192 different water bodies including rivers, streams and tributaries. There are an estimated 12,000 lakes, covering an area of more than 1,200 km^2. The largest lake by area is Lough Neagh, which is estimated to be of the order of 18,870 km^2, with an unknown distribution among the different geological formations.[7]

ELECTRICITY SECTOR OVERVIEW

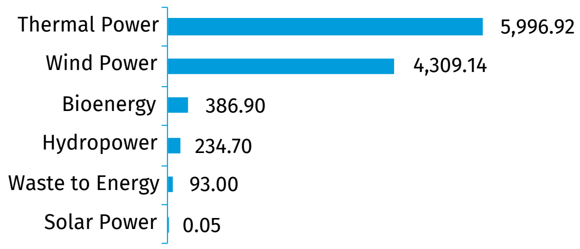
Electricity in Ireland continues to be dominated by non-renewable sources, with coal and peat, until recently, still prominent in electricity generation. However, the share of renewable energy sources in the energy mix is gradually increasing, both in terms of installed capacity and demand, mainly due to an increase in wind power. As a result, carbon intensity of the grid decreased by 14 per cent from 2018 to 2019, reaching 324 g CO_2e/kWh in 2019.[8] In contrast, the carbon intensity of electricity generation in 1990 was 896 gCO_2/kWh.[9]

Total installed capacity in 2021 amounted to 11,020.7 MW, of which 5,996.9 MW (55 per cent) was thermal power capacity (Figure 1). Wind power made up 4,309.1 MW (39 per cent), of which 2,074.1 MW was connected to the transmission system operator (TSO) and 2,235.1 MW to the distribution system operator (DSO).[10,11] Hydropower installed capacity in 2020 was 234.7 MW, or 2 per cent, not including the 292 MW pumped-storage hydropower plant at Turlough Hill.[11] Of the total hydropower capacity, 212.2 MW was TSO-connected and 22.5 MW DSO-connected.[11,12] Bioenergy, waste to energy and solar power made up 386.9 MW, 93 MW and 0.05 MW respectively.[10,11,12]

No new hydropower plants above 3 MW have been installed in the country since the 1950s. However, a large-scale hydropower project, 360 MW Silvermines in County Tipperary, has been deemed a Project of Common Interest by the European

Union, with an expected commissioning date of December 2028.[13]

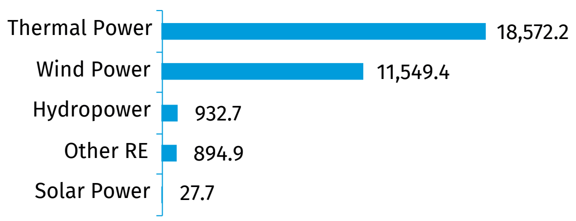
Figure 1. **Installed Electricity Capacity by Source in Ireland in 2021 (MW)**



Source: EirGrid Group[10,11,12]

A total of 31,976.9 GWh of electricity was generated in Ireland in 2020. The main sources of production were thermal, at 18,572.2 GWh (58 per cent) (Figure 2). Natural gas met the majority of demand at 16,250.1 GWh (51 per cent), with contributions in decreasing amounts from peat at 960.4 GWh (3 per cent), coal at 669.2 GWh (2 per cent) and oil 393.5 GWh (1 per cent). Wind power was the dominant contributor to the renewable energy mix for the year 2020 (11,549.4 GWh; 36 per cent), followed by hydropower (932.7 GWh; 3 per cent) and solar power (27.7 GWh; 0.1 per cent). Other renewable sources, including renewable biomass, contributed 894.9 GWh (3 per cent). The remaining 299 GWh (1 per cent) of generation was met by waste to energy, diesel and combined heat and power (CHP) plants.[14] Imports and exports play a very small role via interconnectors linking the country to Northern Ireland and Wales. The net export in 2020 amounted to 0.5 per cent of electricity generation in 2020.[14]

Figure 2. **Annual Electricity Generation by Source in Ireland in 2020 (GWh)**



Source: EirDrid Group[14]

EirGrid is the TSO in Ireland, while further transmission and distribution functions are under the control of the Electricity Supply Board (ESB) Networks Ltd. The Commission for Regulation of Utilities (CRU) is responsible for regulating the electricity market as well as other utilities. An Integrated Single Electricity Market (I-SEM) is in operation on the island of Ireland, facilitated by the North-South interconnector to Northern Ireland.

The future electricity plans for Ireland are guided by the European Commission's National Energy and Climate Plans 2021–2030. Under this plan, 70 per cent of electricity is to be generated from renewable sources by 2030.[15] However, none of the planned or projected increases in renewable electricity production is expected to be met by new hydropower capacity, suggesting that most cost-effective sites have already been exploited. Furthermore, from 2005 to 2018 hydropower only experienced a growth rate of 10 per cent, which was the lowest growth rate of any renewable generation technology in the country.[15]

Ireland has reached a 100 per cent electrification rate. Imports are supported by the East-West Interconnector to Wales with a 500 MW high-voltage direct-current submarine cable.[16] From 2018 to 2019, net electricity imports increased by 673 GWh, representing a shift from Ireland being a net exporter to a net importer of electricity.[8] Further interconnections are being explored through the Celtic Interconnector project, which could link the country to the French transmission grid.[17]

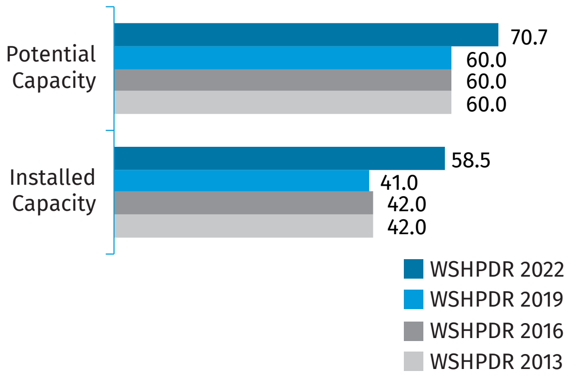
Electricity tariffs in the country are competitive, yet regulated by Electric Ireland, which has the power to enact such mechanisms as price freezes to limit price increases for consumers. In 2021, prices were increased by 9 per cent due to increased wholesale costs and supplier prices, equating to an average of EUR 8.20 (USD 9.70) per month on the electricity bill.[18] Electricity prices are higher than the prices of gas generation, which represents a price distortion and disincentive for consumers to switch to electrified heating solutions. Nonetheless, the average domestic price of electricity (consumption band DC) in the first semester of 2019 was 2 per cent below the Euro Area average.[19]

SMALL HYDROPOWER SECTOR OVERVIEW

This chapter takes the ICSHP definition of SHP as plants up to 10 MW in capacity, which is in line with the common definition used in the country.[20] In 2021, SHP contributed 58.5 MW to the total installed capacity, or 0.5 per cent.[11,12] This indicates an increase in SHP installed capacity of 43 per cent compared to the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 3). This change is due to access to more accurate data sources, plus 0.56 MW of new installed capacity since 2019. In Ireland, the SHP sector comprises 6 TSO-connected plants, with capacities ranging from 0.15 MW to 10.0 MW, and 61 DSO-connected plants, with capacities ranging from 0.02 MW to 4.3 MW (Table 1).[11,12] As of April 2021, there were three new contracted DSO micro-hydropower plants with capacities between 0.04 MW and 0.87 MW under development (Table 2).[21]

Potential capacity in Ireland for small-to-micro-scale hydropower generation is still underexploited, with many sites of less than 1 MW still available for development.[20] According to a report published in 1985, there are 592 potential sites, including those already exploited, with a total of 39.04 MW of potential capacity.[22] Sites with the largest potential are listed in Table 3. The undeveloped potential as of this 1985 report was 34.50 MW. At the same time, in 1985, there was at least 36.18 MW of operating grid-connected SHP capacity.[11,12] Therefore, the total SHP potential in the country, including operational SHP plants is equal to at least 70.68 MW. However, this is likely to be a conservative estimate. The increase in potential capacity compared to the *WSHPDR 2019* is due to access to this more detailed information and improved calculation.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Ireland (MW)**



Source: EirGrid Group,[11] ESB Networks,[12] Irish Hydropower Association,[22] *WSHPDR 2013*,[23] *WSHPDR 2016*,[24] *WSHPDR 2019*[25]

Table 1. **List of Selected Operational Small Hydropower Plants in Ireland**

Name	*Location*	*Capacity (MW)*	*Launch year*
Erne Cliff (1)	Donegal	10.00	1950
Erne Cliff (2)	Donegal	10.00	1955
Lee Inniscarra (2)	Cork	8.00	1952
Clady	Clady	4.30	N/A
Lee Carrigadrohid (3)	Cork	4.00	1952
Liffey Hydro (4)	Wicklow	4.00	1944
Rockygrange Hydroel	Collooney	2.19	N/A
Anarget Hydro	Donegal	2.10	N/A
Trewel Cottoners	Milltown	1.20	N/A
Owenbeg Natural Power	Bantry	0.80	N/A
Curramore mini-hydro	Bantry	0.77	N/A
Mahon Hydro Scheme 2	Kilmacthomas	0.70	2008
Lough Eske	Donegal	0.66	N/A
Lowerymore Hydro	Donegal	0.60	2001
Ashgrove Mill	Kilgarvan	0.60	N/A
Collooney Manufacuring	Collooney	0.50	N/A
Slaheny River Hydro	Bantry	0.49	2002
Barnsbridge Hydro	Donegal	0.48	2001
Nadirkmore Hydro	Westport	0.41	N/A
Parteen Weir	Birdhill	0.40	N/A

Source: EriGrid Group,[11] ESB Networks[12]

The SHP sector is largely run by private developers and small companies. One main deterrent to developing SHP under the current market conditions is due to the lack of a default electricity purchaser for renewable energy supplied into the network since the market decoupling in 1994. This represents a financial risk to new market players.[20]

Table 2. **List of Planned Small Hydropower Projects in Ireland**

Name	*Location*	*Capacity (MW)*	*Planned launch year*	*Stage of development*
Glasha Hydro	County Doon	0.87	N/A	Contracted
The Mill	County Laois	0.04	N/A	Contracted
Avonmore House Hydro	County Wicklow	0.07	N/A	Contracted

Source: ESB Networks[21]

Note: As of April 2021.

According to EriGrid Group, there is limited potential for the expansion of SHP in the country, since it is viewed as a mature technology and there is lack of suitable locations.[26] The sites listed in Table 3 come from a study conducted in 1985 and should be considered as preliminary information on sites that were viable at the time of the chapter writing.

Table 3. **List of Selected Potential Small Hydropower Projects in Ireland**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/refurbishment)*
32(i)	Ballisodare	0.88	5.8	New
32(ii)	Ballisodare	0.74	7.25	New
L11/r48	Cottoners	0.53	335	New
57(ii)	Corrib	0.47	3.9	New
17	Boyle	0.40	3.3	New

Source: Irish Hydropower Association[22]

RENEWABLE ENERGY POLICY

Compared to the neighbouring United Kingdom, in Ireland renewable energy support schemes and policies in general have been lagging behind, with little in the way of planning and policy support. This lack of a clear policy direction and regulatory uncertainty have had an obvious impact on renewable energy penetration in the country, with large producers such as Equinor pulling out of the offshore wind sector as a direct result.[27]

The renewable energy policy is primarily driven by European Union obligations and is described in the National Energy and Climate Plan (NECP) 2021–2030.[15] The related ambitions include: an early and complete phase-out of coal- and peat-powered electricity, an increase in renewable power generation up to 70 per cent by 2030 and meeting 15 per cent of electricity demand with renewable sources contracted under corporate power purchase agreements. There is no specific target for hydropower under the NECP due to the small number of potential sites viable for development.[20]

Apart from this, Ireland has a Transition to a Low Carbon Energy Future 2015–2030 White Paper, which set the target to reduce electricity sector emissions by 80–95 per cent by 2050 and achieve net zero by 2100. This policy provided a target for renewable energy within the electricity consumption of 40 per cent for 2020.[28]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The licensing procedure for SHP in Ireland suggests that potential developers should consult with planning and fishery board authorities in the early stages of the assessment of sites to assess planning friendliness and determine if these actors are likely to contest such a project. In this way, developers can assess the riskiness of pursuing a project in an area based on how friendly they can expect authorities in the area to be, before putting down any funds for the project. Local authorities are responsible for deciding if an environmental impact assessment (EIA) is required. This is usually the case where the project is likely to change at least 30 per cent of the mean river flow. In some cases, an environmental impact statement (EIS) is also required.[20] There are no SHP-specific policy mechanisms in Ireland.

COST OF SMALL HYDROPOWER DEVELOPMENT

The cost of operating SHP in Ireland is high due to initial installation costs, but this is generally recovered over time due to the "free fuel" and low operating costs.[20] Estimates of production costs (OPEX) range from EUR 0.0007 to EUR 0.0015 (USD 0.00083–0.0018) per kWh, depending on the proximity to the electricity grid. Investment cost is estimated to be between EUR 3 million and EUR 12 million (USD 3.54–14.18 million) per MW.[29] The cost is also dependent on the type of generator used, which itself is dependent on the nature of water resources available.[20]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Until 2015, the main incentive for the development of renewable energy in Ireland was the feed-in tariff (FIT), which has now been replaced by the Renewable Electricity Support Scheme (RESS), operated by the Department of Communications, Climate Action and Environment.[30] The programme provides support to renewable energy projects over a 15-year period. The policy objectives of the scheme include: provision of support for communities to participate in renewable energy projects; broadening the renewable electricity technology mix; delivering the renewable energy required under the ambitious Transition to a Low Carbon Energy Future 2015–2030 White Paper; increasing energy security and energy sustainability; and ensuring the cost effectiveness of the energy policy. The first RESS auction occurred in July 2020, with only solar and wind power projects qualifying in the results.[31] To date, hydropower projects have not benefited from either the RESS or the previous FIT scheme.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Future viability of hydropower will depend on the levels of water bodies that are altered by seasonal changes to mean rainfall and on evaporation rates caused by seasonal temperature changes. With no areas of long-term snow or ice cover existing in the country, changes in snow and glacial melt are not considered to be a critical factor. Simulations reported by Met Éireann show projected decreases in mean annual spring and summer precipitation of 0-20 per cent by mid-century, depending on model parameters.[32]

Frequencies of heavy precipitation events are expected to increase during the 2041–2060 time period according to climate simulation models, showing approximately 20 per cent increases during the winter and autumn months.[33] The frequency of extended dry periods are projected to increase substantially by mid-century during autumn and especially summer months, with increases of 12-40 per cent. Temperature projections indicate an increase of 1.0-1.6 °C in mean annual temperatures and up to 2.6 °C on extreme days in summer, with the largest increases to be seen in the east of the country. At the same time, frost days will decrease. The impact of these changes on hydropower generation requires further study for the specific regional hydrological conditions within Ireland.[32]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Hydropower is not projected for growth by the country's NECP because it is largely agreed that few sites suitable for development remain.[15] Ireland does have an abundance of water resources and hydropower plants can produce consistent power throughout the day for the entire year if water levels are high enough. However, the 1985 mapping reported by the Sustainable Energy Authority of Ireland (SEAI) indicates that sources of water suitable for hydropower development remain limited to many small-scale capacity sites of below 1 MW.[34] Micro-hydropower could potentially be viable for small villages or businesses using smaller streams or other sources. However, development costs are likely to be high, including civil engineering, manufacturing and equipment installation. There are also strict environmental regulations and the historical trends of renewable support schemes show that wind and solar power have been disproportionately favoured in the past. There can be considerable public opposition to the construction of plants on popular waterways (e.g., a plant turned down in Kerry), often to protect fisheries and sport fishing.

The following points summarize the main barriers to SHP development that have been identified:

- Increase in hydropower capacity is not envisioned within the NECP 2021–2030;
- Lack of a default purchaser for renewable energy supplied to the network;
- According to EirGrid Group, economically feasible sites have largely been exploited;
- High start-up costs;
- Strict environmental regulations;
- Poor history of qualification for financial support mechanisms;
- Public opposition to SHP within fishing communities;
- Larger capacities of over 1 MW have been for the most part developed.

The following points summarize the main enablers that have been identified:

- Considerable unexploited potential at the small-to-micro scale;
- Support via the RESS auction scheme remains possible, despite a track record of favouring solar and wind power;
- Recent Government-level publications aimed at raising awareness for SHP development and providing advice to potential developers.

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Latvia

Eva Kremere, United Nations Industrial Development Organization (UNIDO); Maris Klavins, University of Latvia

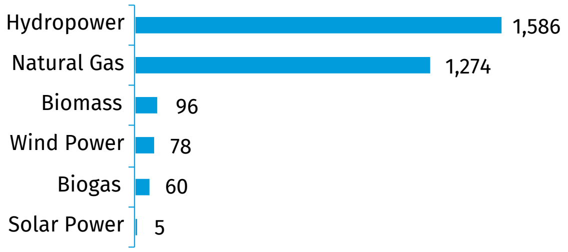
KEY FACTS

Population	1,893,223 (2021)[1]
Area	64,589 km^2[2]
Topography	Latvia can be divided into two parts: a continental part in the east and the Kurzeme Peninsula (Kurland) in the west. The continental part consists of morainic uplands, which are crossed by several rivers flowing to the lowlands. The highest point of the country, the Gaizinkalns Hill with an altitude of almost 312 metres above sea level, is in the Vidzeme Upland. The continental part is separated from the peninsula in the west by the Lielupe River, which flows through the Zemgales Plain. The peninsular part is characterized by the Kurzeme Upland, which is lower than the continental upland and is crossed by several rivers, of which the Venta River is the most important. The highest point in these uplands is at 184 metres above sea level. Overall, approximately 57 per cent of the country lies below 100 metres above sea level and only 2.5 per cent lies above 200 metres.[2]
Climate	Latvia has moderately cold winters, while summers are moderately hot. In the summer (June–August) the average temperature is 17 °C but can occasionally reach 30 °C. During spring and autumn, the weather is relatively mild, but variable and generally humid, with an average temperature of 10 °C. Winters in Latvia usually start in mid-December and last until mid-March. The average temperature in winter is approximately -6 °C but can sometimes reach -25 °C.[3]
Climate Change	Over the last 30 years, the average annual air temperature in Latvia has increased by 0.7 °C. It is becoming increasingly difficult to predict weather with cold waves in winter and heat waves in summer.[4]
Rain Pattern	The average annual precipitation in Latvia is 667 mm. Rainfall is generally higher in hilly regions, on slopes facing moist air masses. The western slopes of the Vidzeme Upland receive 700–800 mm of rainfall annually and the western slopes of the Kurzeme Upland receive 650–700 mm, however, rainfall decreases along the eastern slopes. Much of the rain (70 per cent) falls from April to October, with maximum rainfall (>100 mm) occurring in August. Rainfall is lower in spring. Precipitation, as a constant snow cover, usually starts between the 30th of December and the 5th of January. The thickness of the snow cover exceeds 30 cm in most parts of Latvia; in eastern regions with a hilly topography, the snow cover is 40–50 cm deep.[2,3]
Hydrology	There are 12,500 rivers in Latvia with a total combined coverage of approximately 37,500 km^2. The biggest rivers are the Daugava, Lielupe, Venta, Aiviekste and Gauja. Depending on the physical and geographical conditions, a large share of river discharge comes from either snowmelt, groundwater or direct surface runoff. Approximately 50–55 per cent of the waters of the Daugava, Venta, Lielupe and Musa Rivers is melted snow, while for the Gauja and Amata Rivers it is 35–40 per cent. The total renewable surface water resources are estimated at 16.5 km^3/year and incoming surface water resources at 18.7 km^3/year.[2]

ELECTRICITY SECTOR OVERVIEW

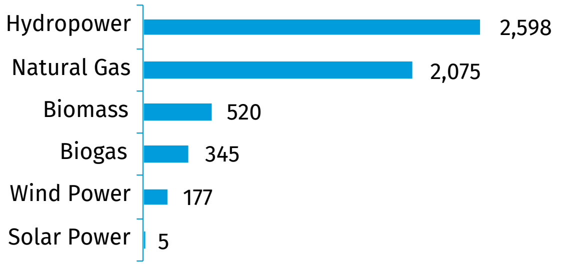
Electricity generation in Latvia is based mostly on large hydropower and combined heat and power plants (CHP) with the rest of the demand being provided for through imports. In 2020, electricity generation in Latvia totalled 5,720 GWh (Figure 1), which is considerably less than in 2016 (6,425 GWh).[5,6] Installed capacity in 2020 was approximately 3,100 MW (Figure 2).[6,7] In the same year, total electricity consumption amounted to 7,138 GWh and total imports reached 4,173 GWh while exports were 2,546 GWh (Figure 3).[8]

Figure 1. **Annual Electricity Generation by Source in Latvia in 2020 (GWh)**



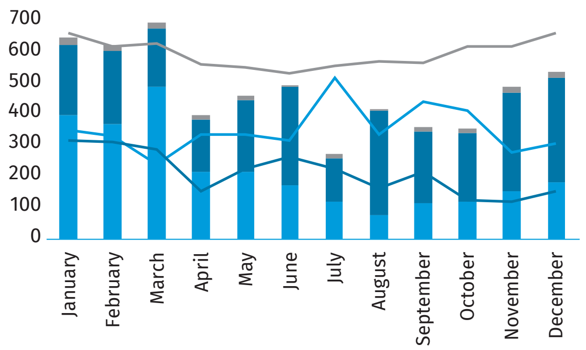
Source: Central Statistical Bureau[5,6]

Figure 2. **Installed Electricity Capacity by Source in Latvia in 2020 (MW)**



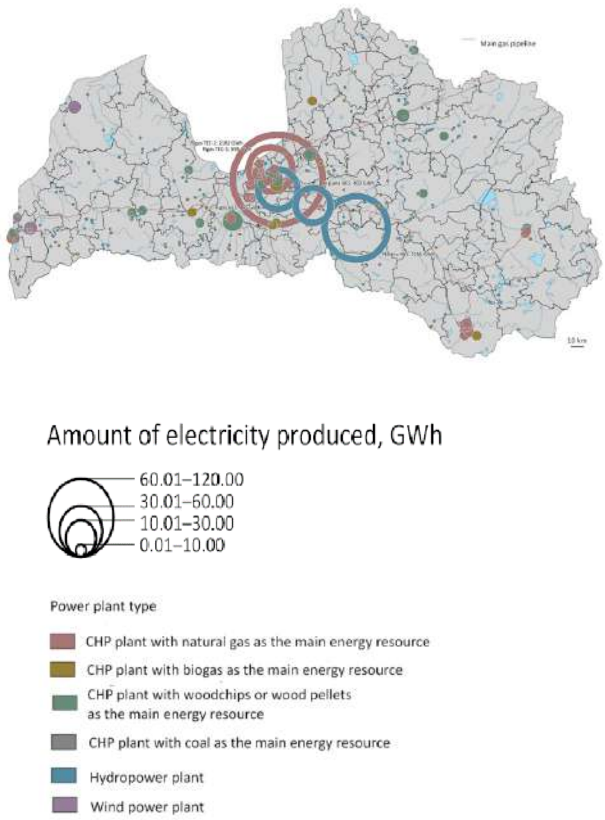
Source: Central Statistical Bureau[6,7]

Figure 3. **Electricity Generation, Consumption, Imports and Exports by Month in Latvia in 2020 (GWh)**



Source: Central Statistical Bureau[8]

Figure 4. **Electricity Production in Latvia in 2019**



Source: Central Statistical Bureau[10]

The greatest share of electricity produced from hydropower was in 2017 reaching 80 per cent (4,386 GWh), while in 2020 it decreased to 45 per cent (2,598 GWh) due to a dry year. At the same time, the installed hydropower capacity in 2020 (1,586 MW) increased by less than 7 per cent compared to 1990 (1,487 MW). There are three large hydropower plants with a capacity of over 10 MW: Kegums at 248 MW, Pļaviņas at 908 MW and Riga at 402 MW (Figure 4).[9] The Latvenergo Group continues the gradual refurbishment of hydropower plants on the Daugava River, which is planned to be completed by 2022.[4]

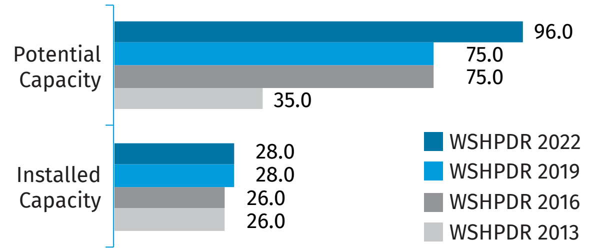
The electricity market is dominated by two state-owned companies: Latvenergo and Enefit (affiliated with the Estonian state enterprise Eesti Energia). The legal framework for the electricity market in Latvia is defined by the Electricity Market Law, which stipulates that the transmission system operator should facilitate the operation of the internal electricity market and cross-border trade, including the support of electricity exchange development.[11] The country is fully electrified and has a distribution network with a total length of 92,656 km.[12] The electricity price in Latvia in 2021 was 61.37 EUR/MWh (72.82 USD/MWh).[13]

Latvia is part of the European Union's (EU) internal electricity market, which operates in accordance with the principles of EU policy and laws. The integration of the Latvian electricity market into the EU market began in 2009. In order to ensure the stability of the electricity market, in November 2020 the Latvia-Russia border was opened for electricity exports from Russia to the Baltic countries. The decision was made following the closure of the Belarus-Lithuania border for electricity trading after the launch of the Astravjec nuclear power plant in Belarus on 3 November 2020.[14]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Latvia is up to 10 MW. The installed capacity of SHP in the country is 28 MW, with generation of 70 GWh in 2020. The potential is estimated to be at least 96 MW (280 MWh of potential annual generation), indicating that 29 per cent of the available potential has been developed.[6,15] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has remained unchanged, while the estimated potential increased by 22 per cent based on more accurate data (Figure 5).

Figure 5. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Latvia (MW)**



Source: *WSHPDR 2019*,[2] Central Statistical Bureau,[6] MHEA,[15] *WSHPDR 2013*,[16] *WSHPDR 2016*[17]

In 2020 there were 147 SHP plants with a total installed capacity of 28 MW and only one SHP plant exceeding an installed capacity of 1 MW (Table 1).[6] The Latvian Renewable Energy Association aimed to have 180 SHP plants with a total installed capacity of 48 MW and generating 140 GWh by 2020, however due to negative social attitudes towards SHP, these plans have been postponed.[19] The theoretical untapped hydropower potential of small and medium-sized rivers in the country is estimated at approximately 1,160 GWh, of which 260 GWh is located on unusable parts of the Venta, Lielupe, Salaca and Gauja Rivers. The economically feasible potential was estimated to be between 450 GWh and 500 GWh, but considering all the possible constraints, environmental hydropower potential could be approximately 250–300 GWh.[20]

Table 1. **List of Selected Existing Small Hydropower Plants in Latvia**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Staškeviču dz.	Aglonas county, Šķeltovas parish, "Staškeviču dzirnavas", Dubnas River	0.17	AG 21	2002
Karļu aizspr.	Amatas count, Drabešu parish, "Kārļi", Amatas River	0.60	AMATAS	2002
Billes	Amatas county, Drabešu parish, Amatas River	0.38	BILLES	2002
Prūšu	Priekuļu county, Virgas pagast, Virgas River	0.20	FIRMA-GA-BRO	2002
Bikstriver	Jaunpils county, Jaunpils parish, "Bikstriver", Bikstupes	0.12	GA 21	2002
Aiviekstes	Aiviekstē, Kalsnavas parish, Madonas county	0.80	Latvenergo	2002
Viduskroģeru	Jelgavas county, Platones parish, "Viduskroģeri", Platones River	0.15	NOVATORS	2002
Lobes dz.	Ogres county, Lēdmanes parish, Lobes River	0.15	Oserviss	2002
Vizlas	Valkas county, Grundzāles parish, Vizlas River	0.32	S&E Management	2002
Rauskas	Mazsalacas county, Ramatas parish, Ramatas River	0.05	SL PLUS	2002
Spridzēnu	Pļaviņu county, Aiviekstes parish, Aiviekstes River	1.20	SPRIDZĒNU	2002
Jaunannas	Alūksnes county, Jaunannas parish, Pededzes River	0.14	ENERGO 2000	2001
Gravas	Ventspils county, Usmas parish, Engures River	0.5	EZERSPĪĶI	2001
Galgauskas dz.	Gulbenes county, Galgauskas parish, Tirzas River	0.52	GALGAUSKAS DZIRNAVU	2001
Ropažu	Ropažu county, Ropažu parish, Lielās Juglas River	0.20	HYDROENERGY LATVIA	2001
Ziedlejas	Jelgavas county, Lielplatones parish, "Ziedlejas", Platones River	0.17	NOVATORS	2001
Krievciema	Pļaviņu county, Aiviekstes parish, "Krievciema ūdensdzirnavas", Viesatas River	0.18	VIORA PLUSS	2001
Zilriver	Zilupe, Raiņa iela 27, Zilupes River	0.12	ZILRIVER	2001
Variņu	Gulbenes county, Rankas parish, Gaujas River	0.32	RANKA HIDRO	2000
Neretas	Neretas county, Neretas parish, Dienvidsusējas River	0.15	NERETAS DZIRNAVAS	1999

Source: Gaujmala[18]

In the late 19th century, Latvia had more than 700 watermills, which were originally powered by wooden waterwheels. SHP plant construction started to expand and by the end of 1926 there were 26 hydropower plants with a total installed capacity of 1.5 MW. During the Soviet period, SHP started to be unprofitable and between 1963 and 1977 all plants were dismantled, even those that were still working efficiently.[20] According to the Latvian Small Hydropower Association, using old watermill locations for SHP development is the best opportunity for development.[21] A total of 367 old watermill sites have been identified.

The public perception of SHP has been negative due to the fact that electricity produced by SHP plants was relatively expensive because of feed-in-tariff (FIT) and mandatory procurement. Furthermore, some SHP plans were badly planned and caused environmental damage.[21] Thus, the EU-funded ECOFLOW project reviewed the situation in Latvian rivers and identified that many SHP plants are damaging the river ecosystems.[22] Those planning mistakes shaped the negative public attitude towards hydropower technology.

RENEWABLE ENERGY POLICY

Directive 2009/28/EC established an obligation for Latvia to increase its share of renewable energy sources in the gross final energy consumption up to 40 per cent by 2020.[23,24,25,26] In order to help reach this target, the Latvian Renewable Energy Federation has estimated feasible development of renewable energy sources for 2020 (Table 2).[27]

Table 2. **Renewable Energy Potential in Latvia in 2020**

Source	*Potential capacity (MW)*	*Potential generation (GWh)*
Biomass	150	760
Biogas	90	720
Wind Power	500	1,500
SHP	75	220
Large hydropower	1,522	3,000
Total	**2,337**	**6,200**

Source: Latvian Renewable Energy Federation[27]

The Regulations on Electricity Generation from Renewable Energy Sources (Cabinet of Ministers Regulation No. 198, initially adopted in July 2007 as Regulation No. 503) prescribes conditions for electricity production using renewable energy sources (wind power, SHP, biomass, biogas and solar power). According to this regulation, producers can sell their electricity under the mandatory procurement component (MPC) at fixed purchase prices (FIT system). For hydropower, the price is calculated based on the following formulae, depending on the type of the plant: price = 188 × *c* × 0.8 × *s* or price = 159 × *c* × *s*, where *c* stands for coefficient (Table 3) and *s* for the adjustment value in case of overpay.

Table 3. **Coefficient Values by Installed Capacity**

Capacity (MW)	*Coefficient (EUR(USD))*
< 0.08	1.240 (1.47)
0.08–0.15	1.231 (1.46)
0.15–0.20	1.202 (1.43)
0.20–0.40	1.131 (1.34)
0.40–0.60	1.086 (1.29)
0.60–0.80	1.072 (1.27)
0.80–1.00	1.055 (1.25)
1.00 –1.50	1.035 (1.23)
1.50–2.00	1.008 (1.20)
2.00–2.50	0.992 (1.18)
2.50–3.00	0.982 (1.17)
3.00–3.50	0.974 (1.16)
3.50–10.00	0.965 (1.14)
10.00–20.00	0.950 (1.13)
20.00–40.00	0.920 (1.09)
40.00–60.00	0.890 (1.06)
60.00–80.00	0.860 (1.02)
80.00–100.00	0.830 (0.98)
> 100.00	0.800 (0.95)

Source: Legal Acts of The Republic of Latvia[28]

To achieve the targets set in Directive 2009/28/EC and promote the production of electricity from renewable energy sources and high-efficiency cogeneration, the MPC is used as a support instrument. It is covered by electricity users as well as by targeted subsidies from the Government.[29] In order to prevent a rapid growth of electricity prices for households, the Ministry of Economics has undertaken a number of actions, including:

- Since 2012 no new licences have been issued to sell electricity under the MPC framework;
- In 2021 the MPC was fixed at 17.51 EUR/MWh (20.8 USD/MWh);
- A support mechanism was created for energy intensive processing companies;
- Overcompensation for power plants was eliminated by setting a maximum allowable profit margin of 9 per cent;
- A differentiation of the MPC as per the connection power was introduced in January 2018.[30]

On 1 January 2018, a new financing model for the MPC entered into force, which was one of the solutions developed by the Ministry of Economics as part of the Industrial Support Programme, whose objective is to increase the volume of the industrial sector by 30 per cent in three years, with a view to improve the international competitiveness of the Latvian industrial sector and reduce the costs of manufacturing for companies. This was one of the reasons why the MPC financing model changed, being divided into two parts — the fixed power component, which depends on the voltage of the electricity connection, and the variable component, which is proportionate to the electricity consumed.[31]

LEGISLATION ON SMALL HYDROPOWER

On 1 January 2014, new Natural Resources Tax Law amendments came into force, stating that owners of hydropower plants with a capacity below 2 MW have to pay a natural resources tax. The tax rate was set at EUR 0.00853 (USD 0.01006) per 100 m^3 of the water flow through the hydrotechnical structure. Previously, the natural resources tax did not apply to SHP plants. Another contested provision deals with the regulation of the Cabinet of Ministers on the procedure for calculating the amount of water flowing through a given plant. In 2015, the Constitutional Court ruled that these amendments are not anti-constitutional and they have therefore remained in force. Moreover, the Court found that the said provisions were not only meant to ensure more efficient and responsible use of natural resources, but also increase budget revenue, which, in turn, could be used to finance environmental protection measures.[15,32,33,34,35]

The development of SHP in Latvia is also limited due to legislative requirements, including the Cabinet of Ministers Regulation No. 27, which protects fish populations and forbids dam construction for SHP plants.[36,37,38]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

As a result of climate change, unusual weather conditions, such as low rainfall, have been observed in recent years in Latvia. Operators of SHP plants are obliged to take these changes into account in their activities. They must ensure the ecological flow and, if the flow decreases below the ecological level, electricity production must be stopped. In such a case, the incoming water in the inflow mode must be discharged downstream. The Government has banned SHP operation in the water storage mode during low water periods. Also, water level fluctuations that may affect the spawning of fish are not allowed.[39]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key factors hindering SHP developing in Latvia are as follows:

- The administrative procedures required for SHP projects are very complicated and time consuming;
- There is a negative public attitude against SHP, including a strong opinion that the previous terms for SHP development were too generous and have harmed the environment;
- Most of the smaller rivers are listed as no-go areas for SHP development;
- A tax for the water flowing through the hydrotechnical structure applies to SHP plants.

The following factors can be considered as enablers for SHP development in the country:

- Available untapped potential, including old watermill sites;
- Incentive system (FIT, MPC) available for SHP plants.

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Lithuania

Egidijus Kasiulis, Vytautas Magnus University

KEY FACTS

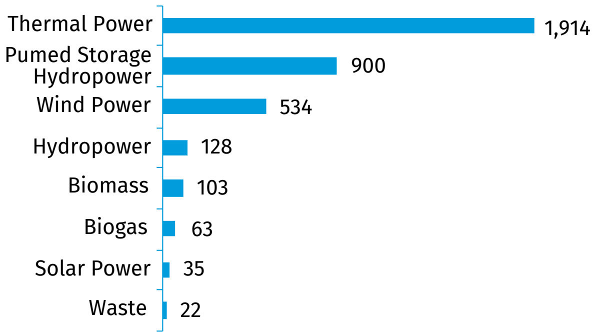
Population	2,793,694 (2020)[1]
Area	65,286 km^2 [1]
Topography	The country's terrain is characterized by lowlands and plains with the highest peak, Aukštojas Hill, reaching 293.8 metres above sea level. Agricultural land covers 52.4 per cent of the total land area; woodland occupies 33.5 per cent of the country's territory and protected areas account for 17.6 per cent. Four per cent of the country's territory is covered with water.[2]
Climate	Climate varies from marine to continental, with moderate winters and summers and sufficient precipitation. The average temperature is lowest in January (-4.2 °C) and highest in July (18.6 °C). The average annual temperature is 6.9 °C.[2]
Climate Change	In the 2011–2016 period compared to 1981–2010 the average annual temperature increased by 0.7 °C, indicating a change of local climate.[2]
Rain Pattern	Precipitation patterns are mostly conditioned by the relief, the position of slopes in relation to the dominating airflows and the distance from the sea. The average annual precipitation rate in Lithuania varies from 800–900 mm on the windward Samogitian Highland slopes to 550–590 mm in the lowlands of central Lithuania. The average annual precipitation rate is approximately 675 mm. The rate of precipitation is sufficient during all seasons and is more intensive during the warm season.[3]
Hydrology	There are 22,200 rivers in Lithuania, with an average density of 1.18 km/km^2. The highest density of rivers is in the central part of the country at 1.45 km/km^2, while the lowest is in the south-eastern part at 0.45 km/km^2. The largest rivers in the country are the Nemunas (length in Lithuania 475 km, average discharge 540 m^3/s), the Neris (235 km, 180 m^3/s) and the Šešupė (209 km, 34.2 m^3/s). There are 2,585 lakes in the country. The greatest number of lakes can be found in the north-eastern part. Furthermore, there are 1,039 reservoirs (ponds) with an area exceeding 0.5 ha, 340 artificial ponds with a combined area of more than 50 ha and a few canals, which are distributed quite equally across the country.[2,4]

ELECTRICITY SECTOR OVERVIEW

The electricity consumption of Lithuania has been growing by a couple of per cent annually. However, this was not the case in 2019, when the annual amount of consumed electricity dropped by 0.3 per cent (to 11.1 TWh) due to an unusually warm winter.[5] The total generated electricity in the same year grew by 13 per cent, amounting to 3.6 TWh (Figure 1).[5] Therefore, almost 68 per cent of consumed electricity was imported. Of the electricity generated domestically in 2019, 58 per cent originated from renewable sources.

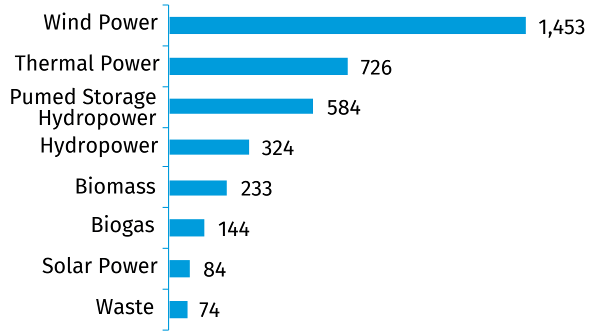
The total installed capacity was 3,699 MW in 2019.[6] More than half of the total, 52 per cent, came from thermal power plants, 24 per cent from pumped storage hydropower, 14 per cent from wind power, 3 per cent from hydropower, 3 per cent from biomass, 2 per cent from biogas, 1 per cent from solar power and 1 per cent from waste incineration (Figure 2). Lithuania is fully electrified.

Figure 1. **Annual Electricity Generation by Source in Lithuania in 2019 (GWh)**



Source: Litgrid[5,6]

Figure 2. **Installed Electricity Capacity by Source in Lithuania in 2019 (MW)**



Source: Litgrid[5,6]

The reliability and security of the energy system of Lithuania is guaranteed by the state-owned company Ignitis Gamyba. It owns and develops strategic electricity generation capacities in Lithuania: the Kruonis pumped storage hydropower plant, the combined cycle unit and reserve power plant in the Elektrėnai Complex, the Kaunas hydropower plant and the Vilnius Power Plant-3.[7] All renewable energy power plants of smaller capacity are owned by the private sector.

The electricity network in Lithuania is modern, able to provide electricity to all consumers also in the event of an accident. Currently, the 400-330-110 kV power transmission grid of Lithuania includes 236 transformer substations and switchyards as well as 7,029 km of power transmission lines.[8] The transmission grid of Lithuania is also well connected to the neighbouring power systems of Latvia, Belarus and the Kaliningrad Region of Russia. During the last decade, two strategic projects were finished, creating international electricity interconnections with Sweden (NordBalt) and Poland (LitPol Link).[8]

A historic change aiming to synchronize the grids between the Baltic States and Continental Europe is planned for 2025. Currently the Lithuanian electricity system is synchronized with the IPS/UPS system that joins Belarus, Russia, Estonia, Latvia and Lithuania into the so-called BRELL ring. The frequency of the Baltic electricity system is centrally managed and coordinated by a centre in Moscow, as a result, in the context of energy integration in Europe, Lithuania, Latvia and Estonia remain an isolated energy island. This energy isolation of the Baltic States in the European Union (EU) will be eliminated once the electricity system has become a full participant in the EU electricity infrastructure and market with synchronous operation with the grid of Continental Europe. After the desynchronization from the IPS/UPS and the synchronization with the Continental Europe Synchronous Area (CESA) via the already existing NordBalt and LitPol links, the Baltic States will start joint operation of a Baltic load-frequency control block.[9]

As a member of the EU, Lithuania follows the European Green Deal objectives and has new goals set by the National Energy and Climate Plan (NECP) for 2030. These include a 45 per cent share of renewable energy in the final energy consumption and a 45 per cent share of renewable electricity.[10] Such an encouragement from the EU is well-timed as the energy strategy currently pursued by the Ministry of Energy of the Republic of Lithuania does not restrict the reliance of the country on electricity imports as long as importing is more cost-effective.[11] However, within the new EU energy policy framework, Lithuania will have to fulfil its obligations to the EU, even if electricity generation from renewable energy sources is more expensive.

In line with the EU Directive 2009/72/EC outlining the common rules for the internal electricity market, the electricity sector in Lithuania has been liberalized. The public companies responsible for the production, transmission and distribution of electricity were established in 2010. Currently, all electricity consumers have the right to freely choose from, and change, independent electricity suppliers as well as to enter into contracts with several suppliers to meet their electricity needs.[12]

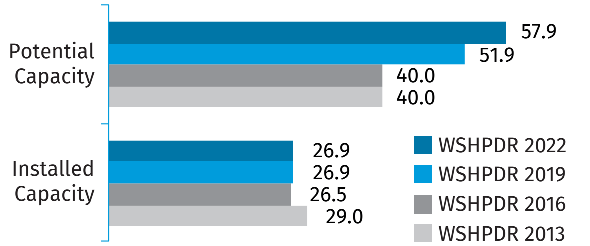
The supervision of the state energy sector in Lithuania is carried out by the National Energy Regulatory Council (VERT). VERT is an independent national regulatory authority (in the EU law sense) regulating activities of entities in the field of energy. Every six months VERT announces the electricity tariffs. The components of the electricity price include the purchase price, the transmission cost, the Public Service Obligations (PSO) tax, the distribution cost, the differential between the public supply price and the actual electricity purchase price as well as the forecasted electricity price from the previous period.[12] In 2021, electricity for end users cost 0.104 EUR/kWh (0.126 USD/kWh) including VAT.[13]

SMALL HYDROPOWER SECTOR OVERVIEW

In Lithuania, hydropower plants with an installed capacity of less than 10 MW are classified as small hydropower (SHP) plants.

In 2020, there were 97 SHP plants in operation and one non-operational plant in Lithuania, with a total installed capacity of 26.9 MW.[6] These plants generated 53,600 MWh of electricity in 2020.[14] The environmental potential of SHP is estimated at 58 MW, indicating that 46 per cent of known SHP potential in the country has been developed. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity remained unchanged, whereas the potential increased by 6 MW (Figure 3). The remaining undeveloped potential of SHP in the country increased from 25 MW to 31 MW as a result of an amendment to the Water Law, which lifted the ban on hydropower development for 170 rivers and their stretches. This amendment implies that the river stretches that were previously not in the protected areas but listed as no-go areas are now open for SHP development.[15]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Lithuania (MW)**



Source: Kasiulis et al.,[16] *WSHPDR 2013,*[17] *WSHPDR 2016,*[18] *WSHPDR 2019*[19]

The most recently commissioned SHP plant was launched in 2017 (Table 1). As of 2020, no plans for new SHP projects were announced in Lithuania.

Table 1. **List of Selected Recently Commissioned Small Hydropower Plants in Lithuania**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Kesiai	Akmenė distr., Agluona River, 56.349267, 22.689263	0.05	6.2	Run-of-river	"Viekšnių malūnas"	2017
Kelmė	Kelmė, Kražantė River, 55.628389, 22.941944	0.06	3.1	Run-of-river, old watermill site	A. Jankauskas	2013
Liubavas	Vilnius distr., Žalesa River, 54.850694, 25.341389	0.02	3.6	Run-of-river, old watermill site	"Europos parkas"	2012
Pagryžuvis	Kelmė distr., Gryžuva River, 55.610111, 23.152444	0.10	6.4	Run-of-river	"Gryžuvos vandenys"	2012
Žerkščiai	Akmenė distr., Venta River, 56.189861, 22.670722	0.03	1.6	Run-of-river, old watermill site	K. Stupuras	2012

Source: BALTPOOL,[14] Bilys et al.[20]

The theoretical potential of SHP in Lithuania is estimated at 417 MW, technical at 172 MW, economic at 121 MW and environmental at 58 MW (Table 2). The estimates are based on a scientific study published in 2004, which calculated the primary hydropower resources for all Lithuanian rivers.[21] The protected areas were screened out and excluded using GIS during the Stream Map project funded by the European Commission's Intelligent Energy Europe programme and published in 2017.[22]

Table 2. **Small Hydropower Potential in Lithuania**

Potential	*Capacity (MW)*	*Generation (GWh/year)*
Theoretical	417	2,093
Technical	171	853
Economic	121	617
Environmental	58	287

Source: Kasiulis et al.[16]

There are no off-grid SHP plants in Lithuania. Every new plant must sign an agreement to sell electricity to the national grid. The SHP market in Lithuania is relatively small; nevertheless, some of the owners of SHP plants also have a secondary SHP plant refurbishment business. Many of these business people established the Lithuanian Hydropower Association over 20 years ago.

The public perception of SHP in Lithuania is becoming slightly negative. It is influenced by environmental non-governmental organizations and the Ministry of Environment of the Republic of Lithuania, which encourage removing in-stream hydraulic structures in Lithuania. Thus, the Bražuolė old watermill weir was removed in 2020 and the removal of the Salantai spillway was scheduled for 2021.[23] These structures did not have SHP plants installed, however, due to this movement the future for SHP can become uncertain.

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

No inventory of potential sites for SHP development has been made available on the governmental level. Therefore, there is no specific list of SHP sites that are available for development in Lithuania.

A recent scientific study following the recommendations of the European Commission to first upgrade existing hydropower plants or use existing in-stream structures for hydropower development revealed that there are over 700 historic and currently non-powered dam sites in Lithuania that could be utilized for electricity generation. The drawback is that most of these sites can be classified as micro-hydropower (potential capacity of less than 100 kW). Therefore, a feasibility study is needed before recommending them as suitable sites for development. Furthermore, many of such sites are in environmentally protected areas, which limits their retrofitting potential.[16]

RENEWABLE ENERGY POLICY

Until 2020, the renewable energy policy in Lithuania was shaped by its commitment to the EU, outlining these commitments and initiatives to develop renewable energy in the National Renewable Action Plan (NREAP). In 2015, Lithuania reached its NREAP 2020 target share of energy from renewable sources in final energy consumption ahead of time.

The next step will be the targets for 2030 set in the NECP, as outlined above. As Lithuania has no plans for the development of large hydropower, all strategies, laws and other documents concerning possible hydropower development as well as an environmental approach to hydropower development mainly concern SHP.

Lithuania reached and exceeded its NREAP targets for 2020 for the installed capacity from solar and wind power but did not reach the target set for SHP due to the strict environmental laws. The Government's prioritization of the development of other than SHP renewable energy sources is demonstrated by the fact that the country's target for the installed capacity of SHP set for 2020 in NREAP was 40 MW and the target set for 2030 in NECP is only 27 MW.[10,16]

The support scheme for electricity generation from renewable energy sources in Lithuania can be called a sliding feed-in premium. The monthly average market price of electricity, determined by VERT, is applied to producers of electricity from renewable energy sources via the support mechanism through PSO. The budget of PSO provides the producer with a payment for the difference between the fixed feed-in-tariffs (FITs) for electricity from renewable energy sources and the price of the sold electricity. This means that the level of support from the state depends on the electricity market conditions.[16]

Until 31 December 2020, the fixed tariff for existing SHP plants was 0.059 EUR/kWh (0.071 USD/kWh).[24] Since 2021, existing SHP plants are not being supported by the state via the FIT and are selling generated electricity at market prices. Additionally, the introduction of a water tax for SHP plants is planned.

For new SHP plants, the fixed tariff and promotional quotas are distributed via reverse auctions. At present, promotional quotas are exhausted in Lithuania and the current fixed tariffs for new power plants are no longer applicable. A new support scheme will likely be implemented in the future based on an approved NECP.[16] It is likely that SHP will have to compete for further support with other renewable energy technologies in reverse auctions.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

There are no specific governmental plans and programmes targeting SHP. In general, the current legislation and regulations are discouraging for SHP developers.

The Renewable Energy Resources Law of the Republic of Lithuania that came into force in 2011 guarantees a simplified authorization for new renewable energy plants with an installed capacity below 350 kW, except for hydropower.[25] This simplified procedure is available only for damless hydropower plants. Currently, there are no such hydrokinetic power plants operating in Lithuania.

The National Energy Independence Strategy was renewed in 2018 and it sets ambitious targets for 2050.[26] This includes a 100 per cent share of consumed electricity to be generated domestically and an 80 per cent share of renewable energy in final consumption. The goal for 2050 is to generate all electricity from renewable energy sources. To reach this goal, significant development of wind power, biomass and solar power is predicted.

The 2019 amendment to the Water Law prohibits dam construction in protected areas and forbids such constructions if they do not meet the good water status requirements according to Directive 2000/60/EB. According to this law, construction of any SHP plant using an existing in-stream structure in a protected area is also prohibited.[15]

COST OF SMALL HYDROPOWER DEVELOPMENT

No dam was built for SHP development since the country regained its independence in 1990. Only existing in-stream structures have been retrofitted for electricity generation. The typical cost per kW of installed capacity for such a type of development ranges from EUR 1,000 to EUR 2,000. This cost includes a technical pre-study, permitting and environmental assessment. Additionally, the investor must take into account if a fish pass is needed. Construction of a fish pass increases the cost of the project by up to 20 per cent.[27]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Subsidies and public support schemes are limited in Lithuania. Therefore, most funding of SHP projects is undertaken by the private sector. For example, in 2013, out of the total investment into the renewable energy sector, 47.3 per cent were loans from banks, 2.4 per cent was support from the EU and 0.2 per cent came from regional and governmental subsidies.[28] Furthermore, it is possible to obtain funding from the EU's structural funds for heritage sites, such as old water mill refurbishments. Still, if this mill is located in an environmentally protected area, there is no possibility to rebuild the old water mill's dam.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The already clearly felt impacts of climate change affect SHP now and may affect SHP development in the future. Draughts caused by hot and dry summers are becoming a common phenomenon. During extensive dry periods, SHP plants cease operations due to the lack of water. Such hot and dry periods alternate with flash floods caused by excessive rain. Since Lithuanian SHP plants are all of the run-of-river type, most of the flash flood water cannot be retained in the reservoir and used for electricity generation.

Winters in Lithuania are now warmer, which means that a long-term snow cover does not form, the peak of spring floods is shifting to the winter months and is in decline. All these climate change impacts cumulate and cause inefficient groundwater levels, which in turn reduces the total amount of water in rivers. Currently, there are no estimations carried out to assess how much electricity is not generated due to the impact of climate change and what adaptation measures will be needed in the future.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Lithuania is a lowland country with modest hydropower resources; however, large parts of the hydropower potential remain untapped. Over more than 100 years of operation, hydropower in Lithuania has proven to be a reliable, efficient and safe source of electricity. Nevertheless, the development of SHP in Lithuania is hindered by strict environmental regulations.

The main barriers for SHP development in Lithuania are:

- Political: There are no governmental incentives, plans or programmes targeting SHP development. Strategies and regulations for the development of renewable energy in Lithuania prioritize other renewable energy sources. Since 2021, the Government does not support SHP plants via the FIT scheme. Additionally, a water tax for SHP plants is planned.
- Environmental: The environmental laws in the country are strict. Retrofitting in-stream structures for electricity generation is prohibited if they are located in protected areas or if they will not ensure a good water status (in line with Directive 2000/60/EC). It was calculated that 39.4 per cent (40.3 GWh/year) of the remaining SHP potential in Lithuania cannot be developed due to the fact that existing in-stream structures are in protected areas.[16] Furthermore, the process of removal of existing in-stream structures has begun in Lithuania.
- Financial: The majority of investments into the SHP sector come from bank loans. Combined with the cancellation of the FIT, this prolongs the payback period, which can make it unsuitable for investors. In the future, it is very likely that hydropower will have to compete for further support with other renewable energy technologies in reverse auctions.

The only enabler in the recent years for SHP in Lithuania that can be listed is:

- Environmental: The amendment to the Water Law that listed 170 rivers and their stretches as no-go areas for hydropower development in Lithuania was lifted in 2019. This implies that the river stretches that were not in the protected zones but were listed as no-go areas are now open for SHP development. Consequently, the remaining untapped potential for SHP in Lithuania increased from 25 MW to 31 MW.[15]

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Norway

Fredrik Arnesen and Seming Skau, Norwegian Water Resources and Energy Directorate

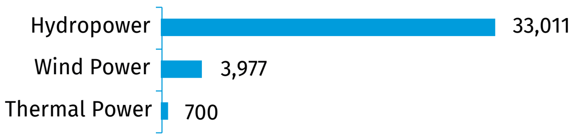
KEY FACTS

Population	5,391,369 (2021)[1]
Area	323,808 km^2 [2]
Topography	The terrain is rugged and mountainous, with the Scandes Mountains spanning the length of the country. The highest mountains are in the south with many summits over 2,000 metres above sea level. In many areas the mountains have characteristic steep sides and flat or rounded tops, particularly in the south and far north where the mountains form a high and relatively flat plateau. On the western coastal sides of the plateau the mountains drop precipitously into deep fjords, whereas the eastern inland slopes of the mountains tend to be more gradual. The highest point is Galdhøpiggen at 2,469 metres.[3]
Climate	Norway covers 13 degrees of latitude and therefore has a large variety in climate and temperature. Temperatures are generally warmer along the south-western coast and colder further inland. The winter period lasts between December and February when mean temperatures can reach as low as -15 °C. Summer lasts from June to August, with average temperatures between 20 °C and 22 °C. During the summer months, the northern regions experience 24-hour sunlight and temperatures can reach above 30 °C.[3]
Climate Change	In Norway, temperatures are predicted to increase, especially in the winter and in the northern parts of the country. The average annual precipitation will increase by 7–23 per cent by 2100. Whether there is an increase, no change or a slight decline in precipitation will vary according to the season and region. There will be more frequent localized, extreme precipitation events, more rapid onset floods in small rivers and more flooding in densely populated and urban areas. River flow in the winter months will generally increase, while river flow in the summer months will generally decrease. The glacial areas will be reduced and glacial melt and discharge from the glaciers will increase in the short term but decrease in the long term as the glaciers melt away.[4]
Rain Pattern	There are large differences in the normal annual precipitation in Norway. Western Norway experiences the largest amounts, in excess of 4,000 mm annually. In these areas, frontal and orographic precipitation dominate and most of the precipitation is received during the autumn and winter months (from September to Autumn). Convective precipitation occurs most frequently in the inner districts of Østlandet (south-east) and Finnmark (north-east). Here summer is the wettest part of the year and winter and spring are the driest.[3]
Hydrology	Depending on the topography, there is a wide variety of water courses in Norway, from larger river basins in eastern and middle regions to smaller and steeper river basins in the mountainous western regions. The longest river is the Glomma, 604 km, and the largest lake is Mjøsa, 362 km^2.[3]

ELECTRICITY SECTOR OVERVIEW

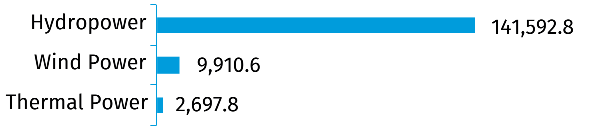
As of 1 January 2021, the installed capacity in Norway was approximately 37,688 MW. Hydropower is the largest source of power generation in the country, with an installed capacity of 33,011 MW (Figure 1). Wind power accounts for 3,977 MW of capacity and thermal power for 700 MW. The country has seen a large increase in development of wind power. In 2020, the total electricity generation in Norway was 154.2 TWh, of which 141.6 TWh, or 92 per cent, was generated from hydropower, with a combination of wind and thermal power generating the remainder (Figure 2).[5]

Figure 1. **Installed Electricity Capacity by Source in Norway in 2021 (MW)**



Source: Statistics Norway[5]

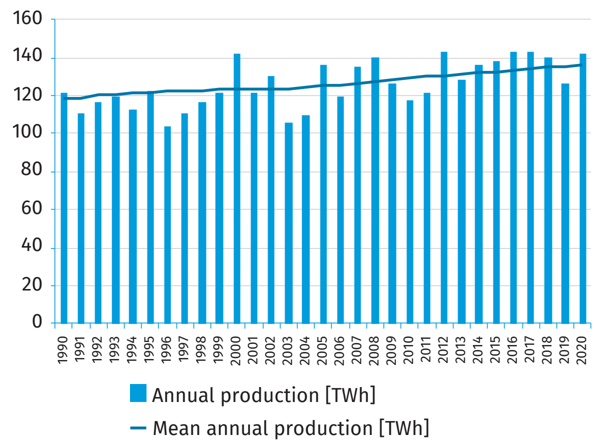
Figure 2. **Annual Electricity Generation by Source in Norway in 2020 (GWh)**



Source: Statistics Norway[5]

Due to the large share of hydropower in the energy mix, the exploitable inflow, i.e., the total amount of the inflow that can be utilized for power production each year, is the most important input factor in the Norwegian power system.[6] The mean annual production of all the hydropower plants installed before the beginning of 2021 was 136,6 TWh. However, there is a significant interannual variation in exploitable inflow for hydropower production in the order of ±20 per cent, affecting the output of the plants (Figure 3).

Figure 3. **Annual Hydropower Generation in Norway in 1990–2020 (TWh)**



Source: Norwegian Ministry of Statistics,[6] NVE

In Norway, both power production and power consumption peak during January. The inflow, however, peaks between April and May. About half of the total hydropower reservoir capacity of Europe, approximately 87 TWh, is located in Norway. Much of this reservoir capacity is used to capture inflow from the summer season for power production during the winter season, to meet the variability of the demand.[7]

In 2021, the total power trading capacity of Norway with other countries increased to approximately 9,000 MW. In May 2021 a new cable to Germany was put in operation and in October 2021 another cable to the United Kingdom, the North Sea Link, became operational.[8] In 2020, Norway imported 4,5 TWh of power and exported 25 TWh.[5]

The electrification rate is 100 per cent. Gross electricity consumption was 133.7 TWh in 2020. The Norwegian Water Resources and Energy Directorate (NVE) estimated in a new report from 2020 that electricity consumption can increase to 163 TWh in 2040.[9] The industry and transport sector will be the largest contributors to the growth.

All grid owners in Norway are obliged to provide a connection to the grid to all new production units. This obligation applies to the existing grid. In areas with many new producers but limited available capacity, the first producer to make a binding agreement with the grid owner is the one that gets connected. All grid owners have the possibility to require the new production units to pay a connection charge according to prevailing regulations.[10]

Before 1991, power producers in Norway were obliged to cover the power demand in specific regions. The power prices were regulated and reflected the long-term marginal costs of the investments in new production capacity that had to take place in order to cover the forecasted future demand in a specific region. In 1991, a new energy act was introduced deregulating the electricity market.[11]

Since then, the Norwegian power market has opened to competition and today Nord Pool Spot organizes the Nordic marketplace for trading electricity. Nonetheless, the Norwegian power industry is dominated by public ownership and a decentralized organizational structure with approximately 10 per cent of annual production sourced from private ownership in the hydropower sector.[5] The wind power sector has approximately two thirds of foreign and private ownership.

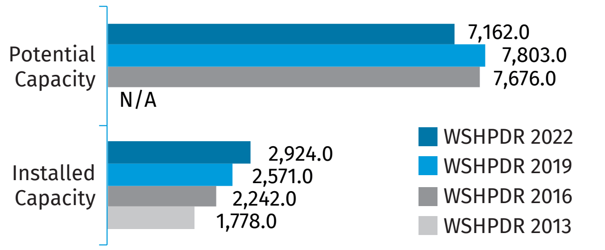
Every day, Nord Pool calculates a day-ahead system price, which is common to the Nordic market. Further Nord Pool calculates prices for the different bidding areas, which takes into account bottlenecks in the transmission system. At the time being, Norway is divided into five different bidding areas and each area can have a different price. The electricity market can be divided into a wholesale market and an end user market. Actors in the wholesale market can be power producers, suppliers and large industrial actors. The suppliers act on behalf of small- and medium-sized end users and industry.[12]

The Government regulates the transmission and distribution tariffs based on the Energy Act and related regulations. The NVE determines annual revenue caps for each individual licence holder. Over a period of time, the revenue shall cover the costs of operation and depreciation of the grid, at the same time giving a reasonable rate of return on invested capital provided effective operation, utilization and development of the network.[13] The total price of electricity for households is made up of the electricity price, grid rent and taxes, with each part constituting approximately one third of the total price.[14] The average price of electricity for households in the first quarter of 2021, excluding taxes and grid rent, was NOK 0.54 (USD 0.06) per kWh. This is 100 per cent higher compared to the same quarter in 2020, which was NOK 0.27 (USD 0.03) per kWh.[14]

SMALL HYDROPOWER SECTOR OVERVIEW

In Norway, hydropower plants with a total capacity of less than 10 MW are classified as small hydropower (SHP) plants, with some exceptions.[15] SHP installed capacity in 2021 was approximately 2,924 MW. The additional technical potential is estimated to be 4,238 MW, of which approximately 1,209 MW (29 per cent) is calculated from known projects that are under construction, have been given licences or have applied for licences.[7,16] This indicates that almost 60 per cent of the available potential capacity remains untapped and approximately 41 per cent has already been developed. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed SHP capacity increased by roughly 14 per cent, whereas the potential decreased by 8 per cent (Figure 4). The decrease in the potential estimate is due to the revised upwards cost of 0.6 USD/kWh for SHP plants and the fact that some areas with hydropower potential have been protected according to nature diversity act.

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Norway (MW)**



Source: NVE[7,16] *WSHPDR 2013*,[17] *WSHPDR 2016*,[18] *WSHPDR 2019*[19]

As of 2021, there were 1,682 hydropower plants in the country, 1,338 (80 per cent) of which were SHP plants (Table 1). More than 80 per cent of these are run-of-river. Combined, they contribute approximately 9 per cent of the installed hydropower capacity in Norway (Table 2). The most significant increase in new hydropower plants in Norway was in the period after World War II and until the mid-1980s. Many of the older SHP plants were closed down due to the interconnection of the grid and the economic viability of new power plants. After the deregulation of the electricity market in 1991 there was more or less a stagnation in the construction of new hydropower plants due to overcapacity and low prices on electricity. This has, however, changed during the last decades, which have seen an increase in the development of new SHP projects. Thus, 936 out of the existing 1,338 (70 per cent) SHP plants in Norway were built during the period from 2000 to 2020.[7]

Table 1. **List of Selected Operational Small Hydropower Plants in Norway**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Valdra	Etne	3.5	280.3	Run-of-river	Valdra Kraftverk AS	2020
Fiveland-selva	Sauda	3.1	244.7	Run-of-river	Fiveland-selva Kraft AS	2020
Storåvatn 1	Rødøy	8.0	442.5	Reservoir	SMISTO Kraft AS	2020
Storlia	Eidfjord	8.5	84.5	Run-of-river	Statkraft Energi AS	2020
Nørland-selva	Mas-fjorden	4.9	129.1	Run-of-river	CK Krafthold-ing Vest AS	2020
Kjeldal-selva	Storfjord-Om-asvuotna-Omasvuo-no	5.0	233.7	Run-of-river	Kjeldalsel-va Kraft AS	2020
Gudåa	Meråker	4.6	248.0	Run-of-river	Meraker Kraft AS	2020
Sædalen	Vaksdal	4.4	160.0	Run-of-river	Sædalen Kraft AS	2020
Øvre Leiråga	Rana	8.5	183.3	Run-of-river	MIP Mil-jøkraft AS	2020
Nedre Leiråga	Rana	3.15	34.7	Run-of-river	MIP Mil-jøkraft AS	2020
Salhuselva	Steigen	3.3	195.0	Run-of-river	Salhuselva Kraft AS	2020
Botna	Sogndal	1.9	332.5	Run-of-river	Botna Kraft AS	2020
Tverrdal-selvi	Sogndal	6.0	225.3	Run-of-river	Tverrrdal-selvi Kraft AS	2020
Osdalen	Volda	4.3	176.5	Reservoir	Tussa Energi AS	2020
Skeids-flåten	Sogndal	4.8	82.2	Run-of-river	Skeids-flåten Kraft AS	2020
Bjørgelva	Sørreisa	2.4	232.3	Run-of-river	Bjørgelva Kraft AS	2020
Nessane	Høyanger	8.6	263.2	Run-of-river	Nessakraft AS	2020
Mølnåa	Selbu	1.5	131.7	Run-of-river	Selbu Energiverk AS	2020

Name	Location	Capacity (MW)	Head (m)	Plant type	Operator	Launch year
Løkkebø	Kinn	2.2	151.9	Run-of-river	Løkkebø Kraftverk AS	2020
Liemyr	Sirdal	1.4	31.0	Run-of-river	Sirdal Kraft AS	2020

Source: NVE[7]

Table 2. **Operational Hydropower Plants by Size and Mean Annual Production in Norway in 2021**

Plant size	Number of plants	Installed capacity (MW)	Generation (TWh)
<1 MW	575	186	0.8
1–10 MW	763	2,738	10.6
10–100 MW	261	9,814	42.9
>100 MW	83	20,273	82.3
Total	**1,682**	**33,011**	**136.6**

Source: NVE[7]

At the end of 2020, 64 SHP plants were under construction and further 267 licensed projects had not yet expired or been realized (Table 3). The potential capacity from known projects that are under construction, received licences or have applied for licences is estimated at 1,209 MW.[15] While there is an economic potential for an additional 3,029 MW, this figure may be misleading as a large share of these sites are unlikely to be granted a licence or the developer has withdrawn the application (Table 4).

Table 3. **List of Selected Planned Small Hydropower Projects in Norway**

Name	Location	Capacity (MW)	Plant type	Developer	Planned launch year	Stage of development
Fennefoss	Evje og Hornes	9.5	Run-of-river	Agder Energi Vannkraft AS	2023	Under construction
Røvatn	Narvik	5.4	Run-of-river	Ballangen Energi AS	2022	Under construction
Dyrkolbotn	Alver	2.7	Run-of-river	Nipo Kraft AS	2022	Under construction
Dalsfos Øst	Kragerø	1.4	Run-of-river	Skagerak Kraft AS	2022	Under construction
Tverrelvi	Voss	4.5	Run-of-river	NGK Utbygging AS	2022	Under construction

Source: NVE[16]

Table 4. **List of Selected Small Hydropower Projects Available for Investment in Norway**

Name	Location	Potential capacity (MW)	Type of site (new/refurbishment)
Vetle Svardalen	Luster	4.9	New
Storelvi Øvre	Luster	5.0	New
Elde	Bremanger	1.2	New
Tokheimselva	Ullensvang	9.1	New
Lauvstad	Drangedal	2.2	New

Source: NVE[16]

RENEWABLE ENERGY POLICY

In 2003, the Government prepared a strategy to increase the development of SHP plants to contribute to new power generation and development of rural areas.[20] Many local developers of SHP plants were not familiar with the process of establishing and operating a new power plant. The focus areas in the strategy included simplification of the licensing process, tax-based economic incentives and establishment of a certificate market for new power production.

Since 1 January 2012, Sweden and Norway have had a common market for electricity certificates.[13] It is based upon the Swedish electricity certificate scheme, which has been in place since 2003. The goal was to increase the annual renewable electricity production in both countries combined by 28.4 TWh by the end of 2020, representing approximately 10 per cent of the current electricity production of the two countries. Sweden has set an additional goal of 18 TWh for the 2020–2030 period, while Norway has not set a new goal after 2020. Norwegian projects which are commissioned during 2021 can participate in the market. Between the start of the certificate scheme in 2012 and the end of March 2021, the scheme has contributed 46.4 TWh of new renewable production between the two countries and hence surpassed its goal. There are still 14.1 TWh under construction, planned to be commissioned during 2021.[13]

The common electricity certificate market is due to continue until the end of 2035. Within the electricity certificate scheme, approved power plants receive one certificate for each MWh they produce over a period of 15 years. Hence, owners of approved plants have two products on the market: electricity and certificates that can be sold independently of each other. From 2012 to 2018, Norwegian producers entitled to certificates received an average of approximately 15 EUR (17 USD) per MWh (based on the average spot price of certificates).[21] Due to the large amount of production in the market and the associated quota obligations, the price has fallen to nearly zero in recent years. This support scheme is technology neutral, which means that all energy sources defined as renewable energy qualify for participation in the electricity certificate market. As of May 2021, 269 new SHP plants in Norway were granted the right to participate in the electricity certificate market, which is included in the goal of 28.4 TWh. To be eligible for participation in the market, the hydropower plant must be built in accordance with the licence and commissioned after 1 January 2012.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Licensing procedures differ depending on many variables, with project size and expected impact being the most important ones. All applications for licences must come with a sufficient description of the project's impact on nature. This is often done through an environmental impact assessment (EIA). An environmental report shall be made for SHP projects, which describes the natural conditions in and along the impacted river stretch. Smaller projects with lesser environmental impact may be handled through simplified procedures.

With some exceptions, the municipality issues licences for SHP plants with capacity of up to 1 MW. The Ministry of Petroleum and Energy (OED) has delegated to NVE to license hydropower projects with capacity of up to 10 MW. After the application is received, a public hearing of the application and EIA, or environmental report in case of SHP projects, takes place. The licence decision can be appealed to OED. NVE's environmental section ensures that the construction, operation and maintenance of hydropower plants are in accordance with the regulations established in the concession. NVE is also responsible for the supervision of dams and appurtenant structures, including approval of plans for construction and rehabilitation and administration of the legal framework for dam safety, also including the development of new technical guidelines.

In nearly all business models between developers and owners of water rights for SHP projects, a rental period of 40 years is common. After 40 years, the contracts must be renewed, expired or terminated. The forty-year timeframe corresponds with the normal economic lifetime, although the estimated lifetime of many components in the SHP plant is shorter. In many contracts, the owner of the water rights (e.g., farmers) are given an option of buying the SHP plant for a fixed price. The most frequently used models are:

- Lending the rights: Lending the rights is a clean model where different kinds of risk sharing can be used. Common for both alternatives is the fact that there is no risk for negative cashflow for the owner of the rights:
- Fixed rent per year, normally based on estimated production in GWh;
- Fixed rate per kWh, risk is shared on the electricity price.
- Share the profit: There are many optional fractions when it is decided to share the profit. A commonly used fraction is the 50/50 principle.
- Fraction of sales: An agreed fraction of the income/sales is close to the 'Lending the rights' in principle, but the owner of the rights is fully exposed to the risk in generation and in electricity prices.
- Private developers: Landowners, farmers and groups of such may organize and develop SHP plants as private business.
- Selling the rights: In very rare situations, the rights to waterfalls have been sold.[22]

Hydropower plants are eligible to get guarantees of origin for their production. There is a range of different products in the scheme of guarantees of origin with different prices, e.g., unsubsidized power.

COST OF SMALL HYDROPOWER DEVELOPMENT

NVE calculates levelized cost of energy (LCOE) for energy projects.[23] For SHP plants, LCOE is calculated at 0.042 USD/kWh and it is expected to remain unchanged in 2030. Operation and maintenance cost is set at 0.005 USD/kWh. The economic lifetime is set at 40 years and discount rate at 6 per cent. In comparison, LCOE for hydropower plants larger than 10 MW of installed capacity is 0.047 USD/kWh.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The hydropower system in Norway has in the last decades experienced more inflow due to increased precipitation, which has resulted in more power production. The increased inflow has been highest during winter and the snowmelt flow decreased. In the future, the inflow is expected to further increase.[4] Most of the increased inflow can be utilized for hydropower production. The inflow during winter will increase, but there will be more variations between the years. Towards the end of the century there will be more rain during the winter. But there will also be winters with little inflow compared to present day levels. The gap between the driest and wettest winters will nearly double from today's level towards the end of the century. Areas with glaciers will experience an increase in inflow due to the melting of the glaciers, until it is reduced after the glaciers have melted. The inflow during summer will decrease due to reduced melting of snow and glaciers. With higher temperatures there will be more evaporation.[24]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

While the country is well-known for its efficient SHP projects, there are certain issues that might affect the future development of the sector:

- There are areas in Norway which have problems with access to both to the local grid and to the central transmission system;
- The cost of developing new wind power has decreased in the last years and it is still expected to decrease in the future, making wind a more economically viable option than SHP.

The following points summarize the main enablers for further SHP development that have been identified:

- Norway has experienced a high amount of development of new SHP projects in the last decade due to the re-regulated electricity market and favourable market conditions. Further development of SHP can be expected.
- There are expectations of higher electricity demand due to electrification and new power-intensive industries.

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Sweden

International Center on Small Hydropower (ICSHP)

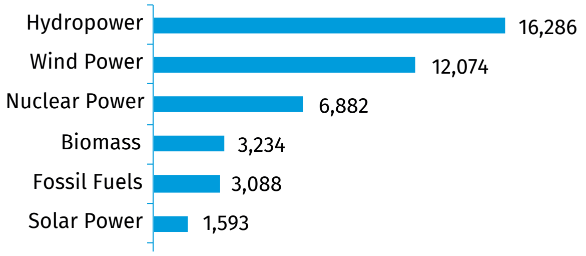
KEY FACTS

Population	10,353,442 (2020)[1]
Area	450,295 km² [2]
Topography	The terrain of Sweden could be categorized with three major regions. Götaland in the south is characterized with highlands in its interior and low-lying plains along the southern coast. The central region, Svealand, is mostly lowlands historically pushed down by glaciers, with the exception of some highlands to the west along the border with Norway. Norrland in the north, the largest and least populated region, has the highest elevations, predominately covered by the Scandinavian Mountains. This region includes Mount Kebnekaise which, at 2,111 metres, is the highest peak in the country, and is located in the far north beyond the Arctic Circle.[2]
Climate	The climate in the south of Sweden is temperate and relatively milder than other places on the same latitude. In the summer, average temperatures in the south are between 15 °C and 17 °C and in the winter, temperatures typically remain between -5 °C and 0 °C. The subarctic climate in the north of Sweden is more severe than in the south. Summers are very short and cool and winters are long and very cold. In the interior of the Norrland region, winter temperatures fall to between -40 °C and -20 °C with harsh winds and only a few short hours of daylight.[2]
Climate Change	Effects of climate change have been experienced in the last few decades in Sweden, with a general warming of average temperatures since the late 1980s. Winter temperatures have increased by between 1 °C and 2 °C, while summer temperatures are also increasing but at a slower rate. Warming temperature trends are expected to continue into the upcoming decades. Additionally, a noticeable increase of precipitation has been occurring since the 1970s with a more dramatic increase since the beginning of the 21st century. In the upcoming decades, continuous increase of precipitation gives concern of increased landslides and erosion.[3]
Rain Pattern	Precipitation happens throughout the year, however, the seasons with the most precipitation are summer and autumn. Average annual rainfall throughout the country is between 500 mm and 800 mm, but varies between regions. Lower amounts of precipitation are experienced in the eastern part of the country and on the islands along the Baltic Sea with an annual average of 400 mm. In the mountains, especially in the north-west, annual precipitation is the highest, averaging between 1,500 mm and 2,000 mm. In the south-west, most wet areas receive from 1,000 mm to 1,200 mm of rainfall per year.[4]
Hydrology	Most of the country's many rivers begin in the Scandinavian Mountains in the north and flow to the south or south-east. The longest is the Klar-Göta River, which begins in Norway and crosses the border to flow south-east through Sweden. Other major rivers are the Muonio and Torne in the north, which form the border with Finland, and the Dal, which flows south-east, cutting through the central Svealand region. The country also has many considerable lakes, which rivers drain into, the largest one being Lake Väner at 5,650 km², located in the south-west.[2]

ELECTRICITY SECTOR OVERVIEW

In 2021, total installed capacity in Sweden was 43,669 MW, of which approximately 77 per cent was with renewable energy sources. Hydropower accounted for 16,286 MW (37 per cent), wind power for 12,074 MW (28 per cent), nuclear power for 6,882 MW (16 per cent), biomass for 3,234 MW (7 per cent), fossil fuels, mostly in the form of gas turbines and cogeneration, for 3,088 MW (7 per cent), solar power for 1,593 MW (4 per cent) and waste for 512 MW (1 per cent) (Figure 1). The fastest growing energy sources in recent years have been wind and solar power. Installed capacity of wind power doubled in six years from just over 6,000 MW in 2015 and surpassed nuclear power as the second largest capacity in 2018. In the same six years between 2015 and 2021, solar power grew from 126 MW to 1,593 MW, over 1,100 per cent. In contrast, nuclear power and fossil fuels have been steadily decreasing during the same years.[5]

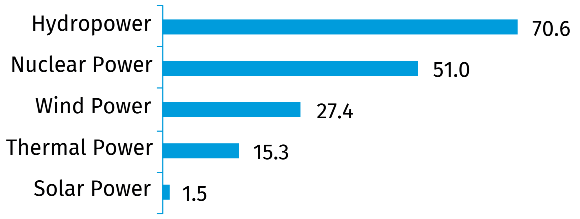
Figure 1. **Installed Electricity Capacity by Source in Sweden in 2021 (MW)**



Source: Swedenergy[5]

In 2021, total electricity generation in Sweden was 165.8 TWh. Hydropower generated 70.6 TWh (42 per cent), nuclear power generated 51.0 TWh (31 per cent), wind power generated 27.4 TWh (17 per cent), thermal power, including biomass and fossil fuels, generated 15.3 TWh (9 per cent) and solar power 1.5 TWh (1 per cent) (Figure 2). Sweden was a net exporter for the year, exporting 33.9 TWh, the majority to Finland, and importing 8.3 TWh, the majority from Norway. Domestic electricity usage was 139.8 TWh and 11.5 TWh were considered losses.[5]

Figure 2. **Annual Electricity Generation by Source in Sweden in 2021 (TWh)**



Source: Swedenergy[5]

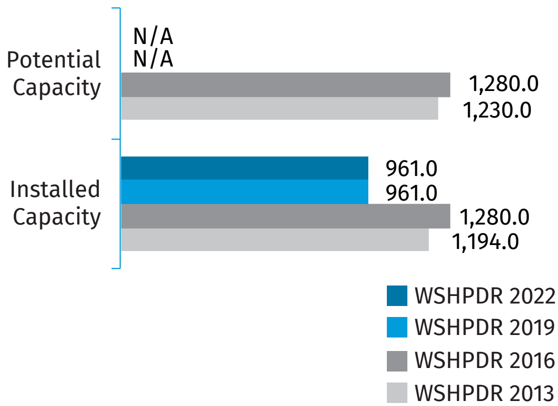
The electrification rate in Sweden is 100 per cent. The electricity sector has been liberalized since 1996, meaning that consumers can choose between several suppliers.[6] While there are many companies that supply electricity in Sweden, the largest companies that, combined, produced over 73 per cent of electricity in 2021 are Vattenfall, E.ON, Fortum, Sydkraft, Statkraft and Skelleftea.[5] Electricity distribution is also liberalized, with over 170 companies, but the same major producers are typically the major distributors. Transmission of electricity is fully state-owned with one company, Svenska kraftnät, responsible for the country's 564,000 kilometres of transmission lines. The transmission lines cross national borders at several locations so that there are interconnections with Norway, Finland, Denmark, Germany, Poland and Lithuania.[6]

The electricity market of Sweden is deregulated and electricity is traded on the Nord Pool market along with the neighbouring countries. The Swedish Energy Markets Inspectorate (SEMI) is the industry regulator responsible for supervising compliance with laws and regulations. The price of the traded electricity can differ depending on operational parameters and the mix of generating capacity. There are four bidding areas (north to south) that display slightly different prices since most of the generating capacity is found in northern Sweden, while much of the demand is found in the south.[6] The average Nord Pool system price for the year of 2020 was 10.95 EUR/MWh (11.76 USD/MWh).[7] Consumer prices of electricity in Sweden include the electricity base price, an energy tax and a value-added tax (VAT). Final prices vary with usage and in 2021 prices typically ranged between 0.17 EUR/kWh (0.18 USD/kWh) and 0.26 EUR/kWh (0.28 USD/kWh).[8]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Sweden is up to 10 MW. The installed capacity of SHP is estimated to be 961 MW.[9] These most recent accurate data for installed capacity are from 2016, but as of 2022, the Swedish Hydropower Association (SVAF) confirmed that installed capacity remained close to 1,000 MW. Exact total SHP potential capacity is unknown. While SVAF estimates that total potential could possibly be up to double of current capacity, no comprehensive feasibility study has been carried out to confirm this.[10] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019,* the installed capacity has remained the same due to lack of an updated exact amount and potential capacity has remained unknown (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Sweden (MW)**



Sources: Eurostat,[9] *WSHPDR 2019,*[11] *WSHPDR 2016,*[12] *WSHPDR 2013*[13]

The first hydropower plant in Sweden was built in the mid-1880s. Between the beginning of the 20th century and the early 1970s, the country saw a steady expansion of hydropower capacity, which provided a secure power supply for industry and also supported the electrification of the country. In 1975, the Government formulated a target of 66 TWh of annual contribution from hydropower to the energy balance by 1985, which was achieved in 1984.[11] Since then, total installed capacity of hydropower has generally levelled out with slight increases and the average generation of hydropower between the years 1984 and 2021 was 67.1 TWh.[5]

As of 2022, there were 1,959 SHP plants in Sweden (Table 1). The combined generation was just under 5 TWh, indicating that approximately 7 per cent of electricity generated from hydropower in 2021 was using SHP. While many of the large hydropower plants are located towards the northern region, most of the SHP plants are located closer to consumption in the southern region. Most of the production occurs between November and April.[10]

Table 1. **Number of Small Hydropower Plants in Sweden by Capacity**

Capacity (MW)	*Number of plants*
0 – 0.125	1,030
0.125 - 1.50	680
1.50 - 10	249
Total	**1,959**

Source: SVAF[10]

While there are currently no government targets or policies explicitly aimed at increasing the capacity of SHP in the country, there are also no specified limitations for development as long as new projects comply with environmental standards, construction regulations and dam safety requirements. There has been little expansion of the number of SHP plants in recent years and it does not seem likely that there will be a drastic increase of plants in the near future. Instead, installed capacity will most likely be increased through the modernization and improved efficiency of existing plants, as recognized by SVAF and the Swedish Energy Agency.

For a country with a long history of hydropower, the current focus is how to align existing hydropower plants with new legislation concerning environmental adherences. Large hydropower supplies a significantly higher percentage of electricity to the grid and serves as a balancing capacity for the power system.[14] Conversely, SHP has a very limited balancing capacity, but is, nonetheless, planned to remain as a contributor to the grid. This is because it helps maintain energy security while having a less substantial impact on the natural watercourses.[10] Another motivation for preserving the country's SHP is that many of the plants are considered important to Swedish cultural heritage.[15]

In order to comply with contemporary environmental standards, a number of fauna passages or bio-channels have been installed around SHP plants. These have the potential to reduce the fragmentation in the river caused by dam construction. However, as a result of many SHP plants being constructed many years ago, it is common that new ecosystems have since been established around them. This has caused owners of plants and related stakeholders to raise concerns of the true net benefits of these installations.

Despite the acknowledgement of the contribution to the energy system that SHP provides, due to, among other things, the old permits linked to many of the existing plants, many organizations are not actively promoting the development of SHP as a better alternative to large hydropower. Environmental organizations, such as the Swedish Society for Nature Conservation, are actively supporting environmental improvements such as bio-channels to existing plants as well as the eco-labelling scheme, Bra Miljöval (Good Environmental Choice) and the environmental funds generated from the purchase of eco-labelled products.[11,15]

RENEWABLE ENERGY POLICY

Sweden has long been committed to increasing the share of renewable energy in the energy sector. Out of all International Energy Agency (IEA) member states, Sweden has the second largest renewable energy share, with only Norway having a share slightly higher. Sweden was the first country to adopt a carbon tax in 1991 and has provided incentives for renewable energy production beginning in 2003 with the electricity certificate system. This is a market-based support system of certificates that supports investments in renewable energy aimed to help reach the goal of 50 per cent of electricity consumption to be with renewable energy by 2020, a goal that was reached. Norway joined the electricity certificate system in 2012 so that certificates can be easily traded in either country. Originally, the certificate system was to be in effect until 2020, but it was extended to 2030 in 2016 and then further extended to 2045 in 2017.[6]

In the 2016 Energy Agreement, targets were set regarding renewable energy. These targets included 100 per cent renewable energy in electricity generation by 2040 and to have a net-zero carbon economy by 2045. It also aimed for another 18 TWh of renewable electricity production to be added through the electricity certificate system between 2020 and 2030. The 2017 Climate Policy provided further framework for achieving these targets, and the Integrated National Energy and Climate Plan of 2020 further elaborated on the country's goals, specifying the roles which different stakeholders would play in achieving these targets.[6,16]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

There are three overarching goals set by the Government in relation to hydropower in Sweden. The first relates to the concession rights — water operators in Sweden should have concessions that are in line with the Swedish environmental legislation and European Union (EU) regulations. The second goal relates to the production with the aim to maintain both production and balancing capacity for hydropower in Sweden. The third goal is to ensure the efficient operation of hydropower.[11]

The water concessions that are linked to the hydropower power in operation today are in most cases based on older legislation. For example, according to a government report from 2014, more than 90 per cent of all hydropower concessions were granted prior to 1983 and, thus, the concession rights are based on the Water Law of 1918 or an even older legislation.[17] Many older SHP plants in Sweden have now been phased out of the Swedish green certificate support scheme. To be entitled to operate for the next 15 years, the plants are required to undergo a total refurbishment of all essential parts. In March 2018, a broad political agreement was reached between the Government of Sweden and several of the parties in the opposition with the aim of addressing the uncertain situation whereby SHP plants were facing the need to re-apply for concessions linked to potentially high legal and consultancy costs. The political agreement means that a more pragmatic approach has been chosen, according to which all hydropower in Sweden should operate based on modern permits, but existing power plants with old permits will have an opportunity to revise their permits instead of re-applying.[18] This opportunity will reduce the need for supporting documentation such as environmental impact assessments (EIA) and reduce administration requirements. This could potentially mean that new SHP initiatives could be taken.

To address the environmental impact of hydropower plants, legislations were passed in 2014 and 2019. In 2014, the National Energy Agency along with the Swedish Agency for Marine and Water Management raised the need for environmental standards to be put on hydropower plants, leading to legislation to be passed requiring it. This meant that existing plants would have to be modernized to adhere to these standards, including installing bio-channels and other mechanisms to maintain the ecological balance of the waters, many of which could be expensive. Consequently, in 2019 a new national plan was agreed upon. The Hydroelectric Environment Fund was created, which can grant plant operators up to 85 per cent of the costs of implementing the required updates as well as for licence revision.[19]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The major barriers to SHP development in Sweden include:

- There are costs involved in providing and generating the supporting documentation for new concession rights, and documentation requirements have been independent of the size of SHP plants;
- There are new strict environmental standards on hydropower plants and mechanisms to adhere to them could be costly.

The major enablers for SHP development in Sweden include:

- The green certificate scheme has been extended until 2045 and provides market-based incentives for hydropower development;
- It is recognized that modernizations of existing plants could considerably increase installed capacity and the Government is committed to ensure the further operation and modernization of these existing plants;
- Hydropower is considered a very important energy source and Sweden acknowledges the long tradition of SHP.

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United Kingdom of Great Britain and Northern Ireland

Gabrial Anandarajah, University College London Energy Institute; and International Center on Small Hydropower (ICSHP)

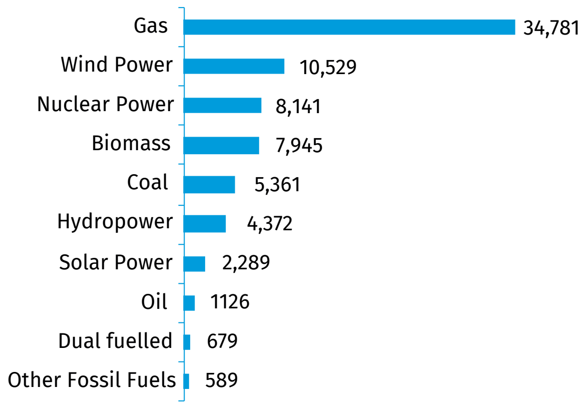
KEY FACTS

Population	67,215,293 (2020)[1]
Area	248,531.52 km² [2]
Topography	The United Kingdom of Great Britain and Northern Ireland (UK) is divided into the hilly regions of the north, west and south-west and low plains of the east and south-east. Scotland in the north is almost entirely rugged, characterized by the northern Scottish Highlands and the Southern Uplands that are separated with a narrow Midland Valley region. Northern Ireland is a western continuation of the topography of Scotland but elevations tend to be lower. Wales also has a predominately rugged terrain due to the northern and central Cambrian Mountains. England is lower and flatter in comparison with the exception of the Pennines Mountains towards the north. The southern and south-eastern regions are mostly low-lying plains. Of the top 10 highest peaks, all are located in either Wales or Scotland. The highest point is Ben Nevis reaching 1,343 metres located in the Scottish Highlands.[2]
Climate	The UK has a temperate climate, with both polar and tropical maritime influenced weather. The polar winds in the winter cause cold, sometimes below 0 °C temperatures in Scotland, while southern England experiences slightly more moderate winters. Tropical maritime and continental winds in the summer cause temperatures to often reach 32 °C, especially in the south.[2]
Climate Change	The UK has already experienced increasing temperatures with an average increase of 0.8 °C since the 1960s and all 10 of the hottest recorded years have been since 1990. In the upcoming decades heat waves are expected to become more prevalent and intense, the rise in sea level caused by melting artic ice will cause increased coastal erosion and rainfall patterns are expected to become more dramatic with a drier dry season and a wetter wet season with concerns of flooding.[3]
Rain Pattern	The mountains of Wales, Scotland, the Pennines in northern England and the moors of south-western England are the wettest parts of the country. Some of these places receive over 5,000 mm of rainfall annually making them some of the wettest locations in Europe. Other parts of the country can be very dry with the southern and south-eastern regions receiving an annual average of less than 800 mm. The wettest months tend to be October and December while the driest months are May and June, but rainfall can be evenly distributed throughout the year in some areas. In winter months, especially in the northern regions, precipitation often comes as snow.[2]
Hydrology	The longest river is the Severn (354 km) flowing through both Wales and England and the second longest is the Thames (346 km).[5] Other major rivers in England and Wales include the Humber, Tees, Tyne, Great Ouse, Mersey and Trent Rivers. The river system of Scotland is largely separate from that of England characterized by many shorter, faster flowing rivers. The two major rivers of the Midland Valley of Scotland are the River Clyde and the River Forth. The longest river in Scotland is the River Tay (188 km).[2] As a result of its industrial history, the UK has an extensive system of canals, mostly built in the early years of the Industrial Revolution.

ELECTRICITY SECTOR OVERVIEW

Electricity infrastructure in the United Kingdom of Great Britain and Northern Ireland (UK) is well developed with a 100 per cent electrification rate.[4] In 2020, total installed capacity was 75,810 MW, of which approximately 30 per cent was with renewable energy and 70 per cent with non-renewable energy. Gas-fired plants accounted for 34,781 MW (46 per cent), wind power accounted for 10,529 MW (14 per cent), nuclear power for 8,141 MW (11 per cent), biomass for 7,945 MW (11 per cent), coal for 5,361 MW (7 per cent), hydropower for 4,372 MW (6 per cent), solar power for 2,289 MW (3 per cent), oil for 1,126 MW (1 per cent) and the remaining 1 per cent was split between 679 MW of dual fuelled plants and 589 MW of other fossil fuels (Figure 1). Total installed capacity has been decreasing since its peak of 90,393 MW in 2010, almost entirely due to the closing of several coal plants amounting to over 18,000 MW and oil plants amounting to over 4,000 MW. Capacity of renewable energy sources has been increasing during the same time, although at a lower rate, with the largest increases in wind (more than 8,000 MW) and solar power (more than 2,000 MW).[5]

Figure 1. **Installed Electricity Capacity by Source in the United Kingdom in 2020 (MW)**

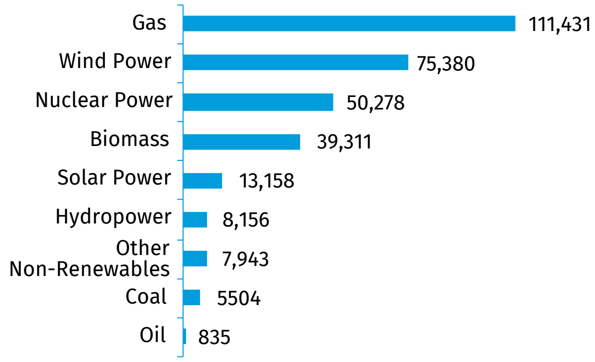


Source: DUKES[5]

In 2020, total electricity generation was 311,997 GWh, of which renewable energy (including renewable thermal energy) accounted for 43 per cent. Gas-powered plants generated 111,431 GWh (36 per cent), wind power generated 75,380 GWh (24 per cent), nuclear power 50,278 GWh (16 per cent), biomass 39,311 GWh (13 per cent), solar power 13,158 GWh (4 per cent), hydropower 8,156 GWh (3 per cent), other non-renewable sources 7,943 GWh (2 per cent), coal 5,504 GWh (over 1 per cent) and oil 835 (less than 1 per cent) (Figure 2). To satisfy a total demand of approximately 329,900 GWh in 2020, the UK imported 17,900 GWh worth of electricity from other parts of Europe. Of the electricity generated, the residential sector consumed 33 per cent, industry consumed 25 per cent, the commercial sector 20 per cent, the energy industry 15 per cent (which includes electricity used for generation and 8 per cent in losses), and the remaining 7 per cent was consumed by public administration, transport and agriculture (Figure 3).[5]

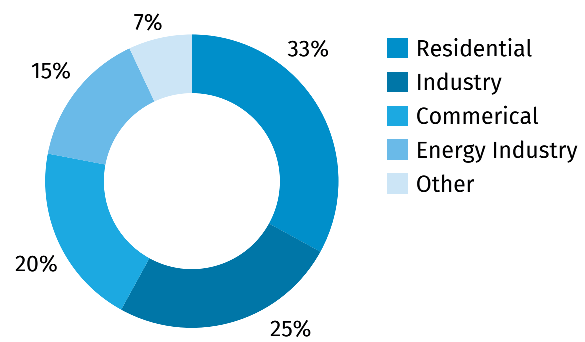
The electricity sector in the UK is fully liberalized, a process that began with the Electricity Act of 1989 and completed in the following years. Electricity suppliers buy electricity from the wholesale market or directly from generators and arrange for it to be delivered to the end customers, who can choose any supplier to provide them with electricity. The market is regulated by the Gas and Electricity Markets Authority, which operates through the Office of Gas and Electricity Markets (Ofgem).[6] Ofgem issues companies with licences to carry out activities in the electricity and gas sectors, sets the levels of return which the monopoly networks companies can make and decides on changes to market rules.

Figure 2. **Annual Electricity Generation by Source in the United Kingdom in 2020 (GWh)**



Source: DUKES[5]

Figure 3. **Electricity Consumption by Sector in the United Kingdom in 2020 (%)**



Source: DUKES[5]

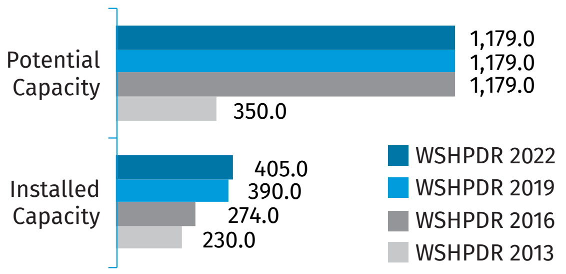
Currently, there are approximately 40 companies in the UK supplying electricity. For several years, there were six major companies that dominated the industry collectively known as the Big Six: EDF, Centrica (British Gas), E.ON, RWE nPower, Scottish Power and SSE plc. However, in 2019 E.ON acquired nPower and the Ovo Group acquired SSE and thus some refer to them now as the Big Five, but an official name is ungiven.[7] National Grid plc is responsible for the transmission network in England and Wales. In Scotland, the grid is split between two separate entities: SP Energy Network (a subsidiary of Scottish Power) is responsible for southern and central Scotland and SSE plc is responsible for northern Scotland. National Grid plc, however, remains the system operator for the whole UK grid. Nine Distribution Network Operators (DNO), operating in 12 separate regions, distribute electricity from the transmission network.[8]

Electricity costs vary across suppliers and regions. In 2021, the national average electricity tariff was 0.164 GBP/kWh (0.20 USD/kWh), similar to the years prior.[9] However, due to the global gas price increase in 2022, average electricity tariffs have increased accordingly. For example, the average tariff for British Gas in April 2022 was 0.28 GBP/kWh (0.35 USD/kWh) and the average tariff for E.ON Energy was 0.27 GBP/kWh (0.33 USD/kWh).[10,11]

SMALL HYDROPOWER SECTOR OVERVIEW

In the UK, small hydropower (SHP) is generally defined as up to 10 MW. In 2020, installed capacity of SHP was 405 MW.[12] Total potential capacity is at least 1,179 MW, indicating that approximately 34 per cent has been developed. It is worth noting, however, that the estimated potential figure is based upon studies with minimum installed capacity limits meaning that sites with capacities below these limits were not included and the total potential should be higher. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity has increased by 15 MW and potential capacity has remained the same (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in the United Kingdom (MW)**



Sources: DUKES,[12] *WSHPDR 2019*,[13] *WSHPDR 2016*,[14] *WSHPDR 2013*[15]

SHP capacity represents just under 10 per cent of total hydropower capacity in the UK. Due to its wet climate, mountainous terrain and plentiful rivers, the large majority of hydropower plants, including SHP plants, are located in Scotland, followed by Wales.[16,17] SHP development in the UK saw expedited growth in the decade since 2010 due to a feed-in tariff (FIT) implemented by the Government that was ended in October of 2019. These FITs, called the Microgeneration Certificate Scheme, were offered to SHP plants under 5 MW. Between 2010 and October of 2019, 1,216 SHP plants with a combined capacity of more than 224 MW were commissioned through this scheme.[18] A list of selected SHP plants is shown in Table 1.

Due to the costs and concerns about its environmental impact, further large-scale hydropower development potential is limited, however, there is scope for exploiting the country's remaining SHP resources in a sustainable way. The good-quality most-financially-viable sites have already been utilized or lie in protected regions of the Scottish Highlands and Snowdonia, Wales. The 2010 England and Wales Hydropower Resource Assessment Report has identified approximately 1,692 potential sites in England and Wales with a combined capacity of between 146 MW and 248 MW.[19] A separate study of Scottish SHP potential carried out in 2008 modelled 36,252 separate sites that were deemed practically and technically feasible. Of these, 1,019 sites with a potential of 657 MW were deemed financially viable. More than half of these sites were estimated to have a capacity of between 100 kW and 500 kW (Table 2).[20] Both studies, however, had lower limits in terms of the potential capacity of sites that were included. For the England and Wales study, a lower limit of 25 kW was set for remote sites and for the Scotland study there were limits of 100 kW for sites in the north of Scotland and 25 kW in the south. This means that a number of pico-hydropower sites were not included, in particular old water mills that could be modernized to generate electricity. With some estimates suggesting there could be 20,000 old water mill sites in England alone, there remains significant potential unaccounted for.[13]

Table 1. **List of Selected Small Hydropower Plants in Operation in the United Kingdom**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Glen Noe	Scotland	2.0	RWE Npower	2021
Grudie	Scotland	2.0	RWE Npower	2017
Cia Aig	Scotland	3.0	RWE Npower	2016
Derrydarroch	Scotland	2.0	Temporis Capital	2015
Upper Falloch	Scotland	0.9	Temporis Capital	2015
Maldie	Scotland	4.0	RWE Npower	2013
Black Rock	Scotland	3.5	RWE Npower	2012
Allt Fionn	Scotland	2.1	Osspower Ltd	2012
Osspower	Scotland	2.0	Temporis Capital	2012
Selset	North England	0.8	RWE Npower	2010
Inverlael	Scotland	2.5	RWE Npower	2009
Carnoch	Scotland	1.4	RWE Npower	2009
River E	Scotland	3.0	RWE Npower	2008
Douglas Water	Scotland	3.0	RWE Npower	2008
Fasnakyle	Scotland	7.7	SSE Group	2006
Kiedler	North England	6.0	RWE Npower	2006
Inverbain	Scotland	1.0	RWE Npower	2006
Kingairloch	Scotland	3.5	SSE Group	2005
Garrogie	Scotland	2.4	RWE Npower	2005
Braevallich	Scotland	2.3	RWE Npower	2005

Sources: DUKES[16]

Table 2. **Potential Small Hydropower Plants by Capacity in Scotland (MW)**

	<100 kW	*100 kW–500 kW*	*500 kW–1 MW*	*1 MW–5 MW*	*5 MW–10 MW*
Number of sites	6	537	300	170	6
Potential capacity (MW)	0.45	150.4	193.2	276.6	36.2

Source: SISTech et al.[20]

RENEWABLE ENERGY POLICY

National Renewable Energy Action Plan of 2009 set a target for 30 per cent of electricity to be sourced with renewable energy by 2020, which was met on time.[21] Having achieved its own target of 31 per cent by 2013, Scotland set the ambitious renewable electricity target of 100 per cent by 2020. This target was almost met, with over 97 per cent of electricity consumption from renewable sources in Scotland in 2020.[22] The Energy White Paper of 2020 states that the UK plans to have 100 per cent renewable energy penetration and a fully decarbonized economy by 2050. However, a year later in October of 2021, the Government announced that the plan to be decarbonized should be achieved by 2035 instead.[23]

Major polices that have been passed in the past decade relating to renewable electricity generation include: the Renewable Obligation (RO), the main support mechanism for large-scale renewable projects; FITs for smaller-scale renewable projects; and Contracts for Difference (CfD). FITs for renewable energy were announced as part of the Energy Act 2008, came into effect in April 2010 and were ended in October 2019. The tariffs applied to electricity generated from plants of no more than 5 MW utilizing hydropower, solar photovoltaics (PV), wind power or anaerobic digestion with an eligibility period of 20 years. Micro combined heat and power (CHP) installations of 2 kW or less were also eligible. After their introduction, the FITs were slowly reduced at regular intervals until they were ended at the end of the decade.[13,18]

For plants greater than 5 MW, the RO was introduced in England and Wales in 2002 and in Northern Ireland in 2005. In Scotland a different but similar policy, Renewable Obligation (Scotland), was also introduced in 2002. The RO requires electricity suppliers to source an increasing proportion of electricity from renewable sources. In order to demonstrate they have met their obligation, suppliers must obtain Renewable Obligation Certificates (ROCs), which are issued to operators of accredited renewable energy plants. Where suppliers do not present a sufficient number of ROCs to meet their obligation, they must pay an equivalent amount into a buy-out fund. In March of 2017, the Government closed down ROCs for new generating capacities in favour of the new CfD scheme, but they are still in place for those using it prior to closure.[24]

The CfD scheme was introduced in 2013 and constitutes a contract between a low-carbon electricity generator and the state-owned Low Carbon Contracts Company (LCCC). According to the scheme, generators are paid the difference between the price for electricity given the cost of investing in a particular low-carbon technology and the country's average market price for electricity. According to the Government, the aim of the new scheme is to give generating companies more exposure to market forces in order to encourage greater efficiency, to reduce uncertainty of revenues and to protect consumers from paying higher costs.[25]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

All hydropower projects must obtain three permissions prior to construction and operation: an environmental licence granted by the relevant regional environmental agency, planning permission granted by the local council or National Park Authorities and accreditation to generate and export electricity provided by Ofgem. To build a new hydropower plant, the developer has to apply to the Environment Agency for:

- an abstraction licence — if water is diverted or taken from a river or watercourse;
- an impoundment licence — if it is planned to build a dam or weir to hold back the flow of an inland water, or if it is planned to change an existing weir or structure as part of the scheme;
- a fish pass approval — if it is planned to install or modify fish passes as part of the scheme;
- an environmental permit for a flood risk activity — when the developer builds in, over or next to main rivers (for rivers and watercourses that are not main rivers the developer must apply to the lead local flood authority for consent).[26]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Barriers to SHP development in the UK include:

- Investment in new SHP plants is limited despite the renewable energy policies;
- The ending of the FIT scheme in 2019 without replacing it with other incentives for small-scale electricity generation;
- Various administrative deliverables needed including the initial financial outlays for the build and for the economic and environmental feasibility studies amongst others.[13]

Enablers for SHP development in the UK include:

- A liberalized sector allows for any company to begin generating electricity, no matter how small;
- There is still undeveloped potential in the country including the old water mills that can be modernized and incorporated into the grid;
- With the newly announced ambition to have a decarbonized energy sector in less than 15 years, SHP can be a key tool towards this goal as it has lower start-up costs and faster construction times than large projects.

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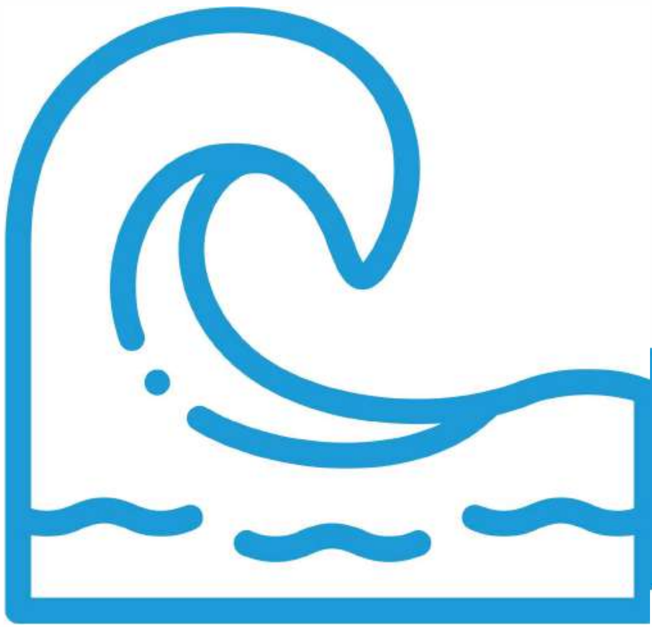


4.3. Southern Europe

Countries: Albania, Bosnia and Herzegovina, Croatia, Greece, Italy, Montenegro, North Macedonia, Portugal, Serbia, Slovenia, Spain

INTRODUCTION TO THE REGION

The electricity sectors of countries in Southern Europe are highly integrated due to the participation of all countries in the region in the Energy Community. The Energy Community seeks to harmonize the legal and regulatory frameworks governing the electricity sectors of member nations of the European Union (EU) and non-member nations, including Albania, Bosnia and Herzegovina, North Macedonia, Montenegro and Serbia, participating under the status of Contracting Parties. Additionally, all countries in Southern Europe are connected to the European Network of Transmission System Operators for Electricity (ENTSO-E), which ensures synchronous operation of their national electricity grids. Electricity access in the region is universal.

At the same time, countries in Southern Europe have adopted different strategies in developing their electricity sectors, particularly with regard to reliance on renewable energy sources (RES). Italy and Spain have the largest and most diversified electricity sectors in Southern Europe, with Italy leading the region in solar power capacity. Spain leads the region in wind power, which forms the mainstay of its electricity production and in 2022 outpaced both conventional thermal power and nuclear power in the share of the country's installed capacity and annual generation. Non-hydropower RES including wind power and solar power collectively form the second-largest source of electricity generation in Greece, after gas-fired thermal power plants, as the country has been in the process of phasing out coal power plants. Conversely, coal is the main source of electricity generation in Serbia, and thermal power from various sources also dominates the electricity sectors of Bosnia, North Macedonia and Italy. In Slovenia, nuclear power accounted for the single-largest share of annual electricity generation in 2020.

Hydropower plays an important role in the electricity sectors of all countries in Southern Europe, but its share of annual generation and installed capacity varies considerably by country. Hydropower is the leading source of electricity generation in Albania, where it accounts for nearly 100 per cent of all generation and installed capacity, as well as in Portugal, Montenegro and Croatia. Italy leads the region in both installed hydropower capacity and generation, but the role of hydropower in the country's energy mix is secondary to thermal power. In other countries of Southern Europe, hydropower plays a supplementary role.

An overview of the electricity sectors of the countries in the region is provided in Table 1.

Table 1. **Overview of Southern Europe**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Albania	3	100	100	2,275	5,208	2,162	5,186
Bosnia & Herzegovina	3	100	100	4,531	15,391	2,249	4,618
Croatia	4	100	100	5,211	12,005	2,127	5,871
Greece	11	100	100	20,400	37,989	3,170*	2,958*
Italy	60	100	100	116,383	271,648	22,695	48,952
Montenegro	1	100	100	1,029	3,744	684	1,697
North Macedonia	3	100	100	2,088	5,658	698	1,183
Portugal	10	100	100	22,421	49,324	7,129	13,811
Serbia	7	100	100	8,285	35,540	3,050	9,701
Slovenia	2	100	100	3,924	15,748	1,347	5,106
Spain	47	100	100	114,196	259,905	20,425	32,244
Total	-	-	-	**300,742**	-	**65,736**	-

Source: *WSHPDR 2022*[1]

Note: *Includes only large hydropower. Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

Most countries in Southern Europe adhere to the definition of small hydropower (SHP) established by the EU, which includes hydropower plants with an installed capacity of up to 10 MW. However, Greece and Albania define SHP as plants of up to 15 MW. Slovenia uses the up to 10 MW definition for water management purposes, and the up to 1 MW definition for the purpose of regulating and incentivizing RES, with plants of up to 1 MW receiving significantly higher operating support tariffs than plants of up to 10 MW.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Southern Europe (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Albania	Up to 15 MW	482.0	N/A	432.0	1,963.0
Bosnia & Herzegovina	Up to 10 MW	172.2	1,005.0	172.2	1,005.0
Croatia	Up to 10 MW	45.7	100.0	45.7	100.0
Greece	Up to 15 MW	247.2	2,000.0	N/A	N/A
Italy	Up to 10 MW	3,648.4	7,073.0	3,648.4	7,073.0
Montenegro	Up to 10 MW	34.7	97.5	34.7	97.5
North Macedonia	Up to 10 MW	111.4	258.0	111.4	258.0
Portugal	Up to 10 MW	415.0	750.0	415.0	750.0
Serbia	Up to 30 MW	N/A	N/A	109.0	109.0
Slovenia	Up to 1 MW	N/A	N/A	164.0	180.0
Spain	Up to 10 MW	2,145.0	2,158.0	2,145.0	2,158.0
Total	-	-	-	**7,277.4**	**13,693.5**

Source: *WSHPDR 2022*[1]

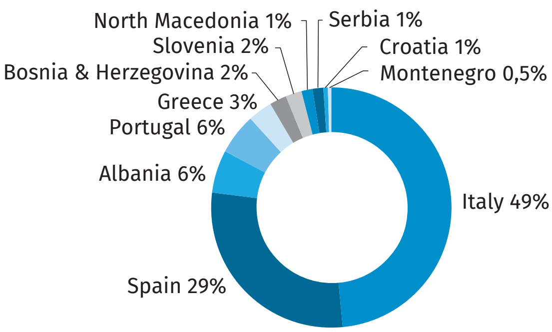
Note: *Based on installed capacity.

The total installed capacity of SHP of up to 10 MW in Southern Europe is 7,277.4 MW, while potential capacity is estimated at 13,693.5 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has increased by nearly 6 per cent as a consequence of ongoing SHP development, while the estimate of SHP potential has decreased by 7 per cent, mainly due to a lack of recent and reliable data on the SHP potential of Greece and Serbia.

Active development of SHP is ongoing across most countries in Southern Europe, with Italy adding several hundred megawatts of new SHP capacity in recent years and Albania and Bosnia and Herzegovina nearly doubling their respective SHP capacity totals. At the same time, public opposition to the development of SHP and hydropower in general is increasing in the region, fuelled by concerns over environmental impact and water scarcity. Additionally, the identified SHP potential of some countries in the region, in particular Spain and Slovenia, is approaching saturation.

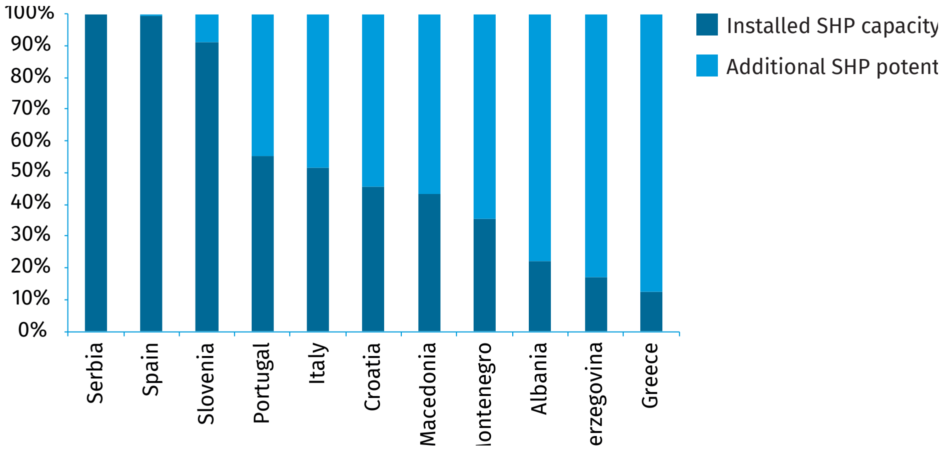
The national share of regional installed SHP capacity by country is displayed in Figure 1, while the share of total national SHP potential utilized by countries in the region is displayed in Figure 2.

Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Southern Europe (%)**



Source: *WSHPDR 2022*[1]

Figure 2. **Utilized Small Hydropower Potential by Country in Southern Europe (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP of up to 10 MW except in the case of Greece, where the local definition is used due to a lack of data on potential capacity for SHP of up to 10 MW.

Albania has an installed capacity of 432 MW for SHP of up to 10 MW, while potential capacity is estimated at 1,965 MW, indicating that 22 per cent has been developed. The installed capacity for SHP of up to 15 MW is 482 MW, provided by 122 plants. The country has nearly doubled its installed capacity for SHP of up to 10 MW between 2017 and 2019, owing in part to strong support for the sector in the form of feed-in tariffs (FITs) and guaranteed off-take of electricity.

In **Bosnia and Herzegovina**, the installed capacity of SHP of up to 10 MW is 172.2 MW, while potential capacity is estimated at 1,005 MW, indicating that 17 per cent has been developed. The country is actively pursuing SHP development, nearly doubling its installed capacity in recent years. As of 2021, there were 115 SHP plants in operation and an additional 341 SHP projects in various stages of completion. However, generation of electricity from SHP decreased dramatically between 2019 and 2020 due to changing hydrological conditions.

The installed capacity of SHP of up to 10 MW in **Croatia** is 45.7 MW provided by 39 plants, while the feasible potential capacity is estimated at 100 MW, indicating that nearly 46 per cent has been developed. There were at least 29 additional SHP projects in the country as of 2019 in various stages of approval.

Greece has an installed capacity of 247.2 MW for SHP of up to 15 MW, while potential capacity is estimated at 2,000 MW, indicating that approximately 12 per cent has been developed. There are approximately 120 SHP plants operating in the country. Despite rising SHP capacity, generation from SHP has been steadily decreasing over the last several years due to prevailing dry climatic conditions. The country plans to increase its total SHP capacity to 350 MW by 2030, and 70 MW of new SHP projects were awaiting implementation as of 2020.

The installed capacity of SHP of up to 10 MW in **Italy** is 3,648.4 MW, provided by 3,271 plants of up to 1 MW and an additional 922 plants with installed capacities of 1–10 MW. Potential capacity is estimated at 7,073 MW, indicating that approximately 52 per cent has been developed. The SHP sector in the country has been growing at a rapid pace in recent years. New SHP projects have increasingly focused on utilizing existing water supply networks such as aqueducts, with 24 such projects authorized for construction in 2020 alone. Growth in the SHP sector of Italy is driven by comprehensive support schemes including FITs, auctions and other incentives.

Montenegro has an installed capacity of 34.7 MW for SHP of up to 10 MW, while potential capacity is estimated at 97.5 MW, indicating that approximately 36 per cent has been developed. Although SHP development in the country had stagnated for several decades, the sector has revitalized starting in 2013, and 16 new SHP plants were commissioned by 2019. Fifty-five new SHP projects are in various stages of development.

The installed capacity of SHP of up to 10 MW in **North Macedonia** is 111.4 MW, while potential capacity is estimated at 258 MW, indicating that 43 per cent has been developed. There are 101 SHP plants operating in the country. The recent pace of construction has been high, with several new SHP plants commissioned per year between 2017 and 2020.

Portugal has an installed capacity of 415 MW for SHP of up to 10 MW, while potential capacity is estimated at 750 MW, indicating that 55 per cent has been developed. Previous plans had aimed to achieve a total SHP capacity of 750 MW from 250 plants by 2020, but as of 2021 these plans had not been realized. The pace of construction of new SHP plants in the country has slowed significantly since 2017. There are no concrete plans for any additional SHP projects, with ongoing construction in the hydropower sector focusing on large plants.

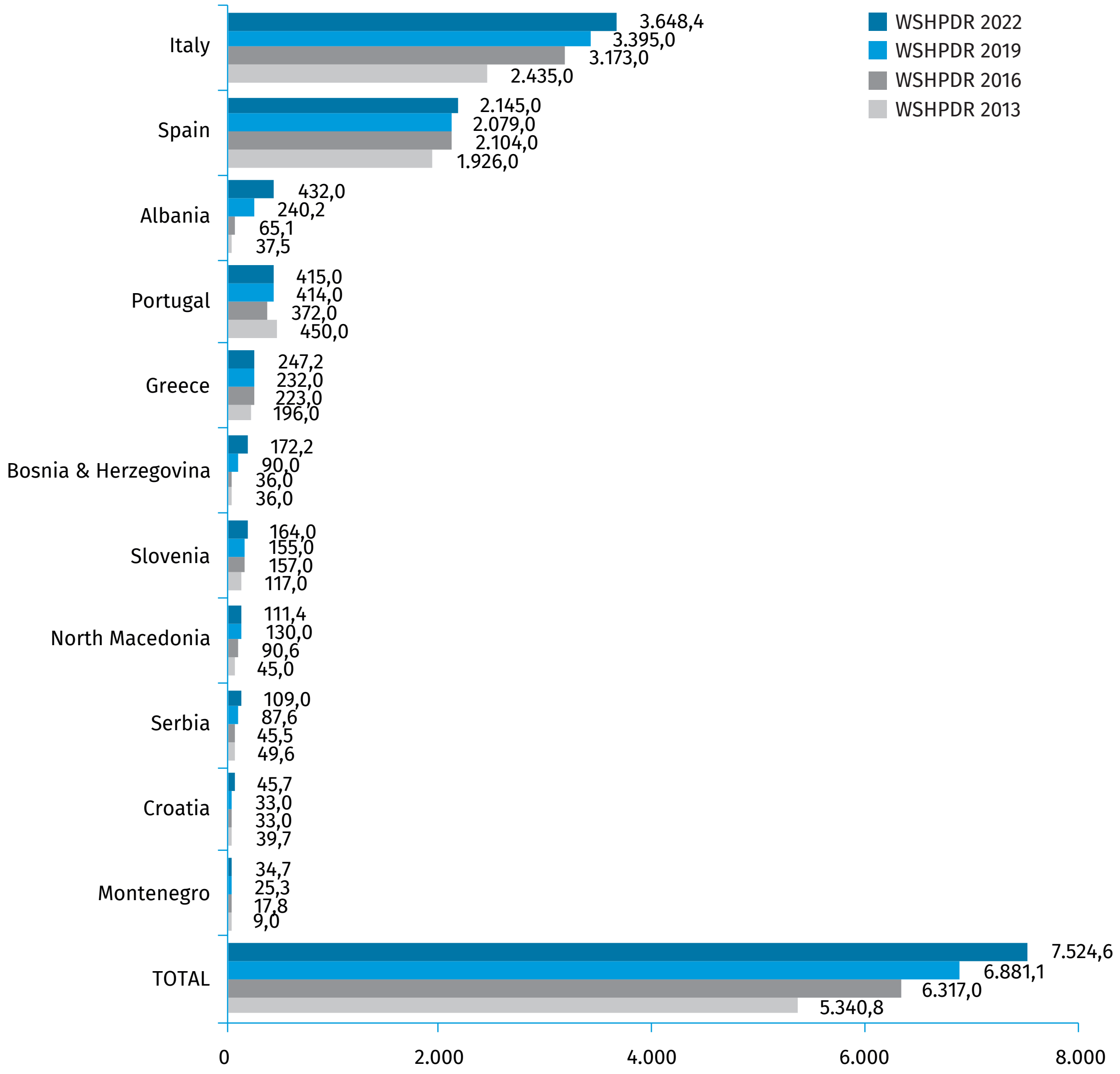
There are 138 SHP plants of up to 10 MW operating in **Serbia**, with a total installed capacity of 109 MW. There are no reliable recent estimates of the country's potential SHP capacity, although previous estimates suggested a potential of several hundred megawatts. The latest estimate of potential was carried out in the 1980s and is no longer considered representative in light of the changing hydrological conditions in the country. Nevertheless, Serbia is actively developing its SHP sector, with many new plants commissioned in 2020–2021, and efforts to produce an updated database of potential SHP sites are also underway.

The installed capacity of SHP of up to 10 MW in **Slovenia** is 164 MW, while potential capacity is estimated at 180 MW, indicating that approximate 81 per cent has been developed. A moderate expansion of the country's SHP sector is planned, with total installed capacity expected to reach 177 MW by 2040. However, strategic development plans have emphasized the refurbishment and modernization of existing SHP plants rather than new construction.

Spain has 1,098 operating SHP plants of up to 10 MW, with a total installed capacity of 2,145 MW. Potential capacity for SHP of up to 10 MW is estimated at 2,158 MW, suggesting that nearly all potential has been developed. Active development of the SHP sector in the country has been continuous since the 1980s, but it remains unclear what additional SHP projects can be realized in light of the increasingly limited remaining undeveloped potential.

Changes in the installed SHP capacities of countries in the region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in Southern Europe (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

Note: For SHP of up to 10 MW except in the case of Greece, where the local definition is used for the purpose of comparison with the previous editions of the *WSHPDR*.

Climate Change and Small Hydropower

The Mediterranean region is already experiencing a much drier climate, relative to historical observations. A decrease in generation from SHP plants has been observed in Greece since 2018. Studies suggest that by 2070, hydropower generation in Italy will decrease by 22 per cent, and a decrease of 5–43 per cent in specific river basins is expected in Spain.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Albania is currently planning to diversify its energy mix away from an almost exclusive reliance on hydropower and develop additional solar power and wind power capacities. Furthermore, there is significant social resistance to new hydropower projects, which has already led to the cancellation of plans for hydropower development in parts of the country. Nevertheless, the country has considerable untapped SHP potential, which remains to be realized.

A key barrier to SHP development in **Bosnia and Herzegovina** is the negative perception of SHP on the part of the population due to poor construction and oversight of plants leading to environmental damage, as well as due to a lack of consultation with local communities on SHP projects. Recent legislation aims to significantly restrict or prohibit SHP construction in the country. The main enabler of any future SHP development is the country's large undeveloped SHP potential.

Barriers to SHP development in **Croatia** include a lack of funding due to high upfront costs, strict regulations, a complex structure of licensing agencies and opposition from the country's tourism sector to the use of watercourses for SHP construction. At the same time, Croatia is committed to the further development of RES, and SHP potential in the country has been carefully mapped by previous studies.

Development of SHP in **Greece** is hampered by the decreasing hydropower output of existing plants, lengthy licensing procedures, an absence of a national water management plan, which has led to increased competition among water users, and the lack of interest in SHP development on the part of investors due to low profit margins. The main enabling factor for SHP development in Greece is the country's remaining undeveloped SHP potential.

Barriers to further SHP development in **Italy** include public opposition to SHP projects in some parts of the country, recent reductions in FIT support and the lengthy periods required for authorization of SHP projects. However, Italy is a regional leader in the SHP sector and a global centre of SHP research, and SHP developers in Italy can rely on significant local technical, scientific and manufacturing capacity, in addition to a well-developed framework of incentives. The remaining SHP potential in the country is significant and offers many opportunities for new projects if the momentum of development is maintained.

Although the SHP sector in **Montenegro** has revitalized over the last decade, public opposition to new SHP construction has resulted in the Government cancelling some SHP contracts. Costs and complexity of ensuring grid connections and a lack of detailed data on potential sites have posed additional obstacles to new development. Enablers for further growth in the SHP sector of Montenegro include demand for increased security of electricity supply, a competitive electricity market and the possible role of SHP projects as mechanisms of job creation, particularly in the less developed parts of the country, particularly if these projects were to be carried out by local companies.

SHP development in **North Macedonia** faces several challenges including a lack of accurate hydrological data on potential sites, cost and difficulty of grid connections, and lack of local manufacturing capacity driving high development costs. At the same time, the SHP sector benefits from FITs and access to loans from local banks, availability of local technical expertise, substantial undeveloped SHP potential and a generally favourable political and social climate for SHP development.

One of the main barriers to SHP development in **Serbia** is the lack of up-to-date information on potential sites or even a reliable overall estimate of the country's SHP potential. Additionally, lack of proper oversight of construction and operation of SHP plants in the country has led to negative environmental impact and generated public opposition to SHP construction. In this context, the most prospective sites for future SHP development in Serbia are likely existing non-powered dams as well as pressure break elements on existing pressurized water systems.

In **Slovenia,** a lack of collaboration between various stakeholders connected to SHP development, lack of human and technical capacities, and mistrust towards SHP development from the general public due to previous violations of environmental requirements by existing plants have hampered growth of the SHP. Current environmental regulations in the country favour the development of large hydropower. Nevertheless, SHP enjoys support in the form of FITs and other incentives, and ample potential for new projects exists both in terms of new stream development as well as in the modernization of existing plants.

The main barrier to SHP development in **Spain** is the almost-fully developed identified SHP potential. Competition with other water users and complicated licensing procedures have also hampered development of SHP in the country, with the additional issue of existing SHP plants running the risk of losing water use licences after a certain period and being abandoned. There are no clear enablers to further development of SHP in Spain other than the liberalized structure of the country's electricity market, which favours private electricity producers.

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Albania

Julien Jomaux and Gjergji Simaku, Ministry of Infrastructure and Energy

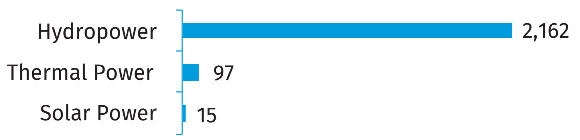
KEY FACTS

Population	2,854,191 (2019)[1]
Area	28,748 km^2[2]
Topography	The topography of Albania is mostly mountainous, with small plains along the coast and river valleys. Mount Korab, situated in the east, at the border with North Macedonia, is the highest peak at 2,751 metres above sea level.[2]
Climate	Albania lies in a transition zone between the Mediterranean and the moderate continental climates. On the coastal plain, winters are cold, cloudy and wet, while summers are hot, clear and dry. In the mountainous interior part of the country, the summers are characterized by rainfall and winters are colder. The average annual temperature is 15 °C, while the minimum average temperature is 1.6 °C and the maximum average temperature is 20.9 °C.[2]
Climate Change	The impact of climate change in Albania is expected to encompass an increase in temperatures and a decrease in precipitation, particularly, during the summer. This could lead to a reduction in water quality and quantity, negatively impacting hydropower generation.[3]
Rain Pattern	The average annual rainfall is 1,430 mm, with 1,000 mm on the coast and over 2,500 mm in the mountains. Approximately 70 per cent of the rainfall occurs from November to March.[3]
Hydrology	Albania is considered rich in water resources and its hydropower potential plays an important role in the development of the country. There are more than 150 smaller rivers and torrents forming eight main big rivers. These rivers have a south-east to north-west flow, predominantly oriented towards the Adriatic coast. The most important rivers are the Drin (340 m^3/s), Vjosa (210 m^3/s), Seman (101 m^3/s), Mat (74 m^3/s) and Shkumbin (60 m^3/s). The total average flow of all the rivers in the country is approximately 1,245 m^3/s. Despite having small flows, the considerable inclination of the Albanian rivers, due the country's mountainous terrain, makes them important for hydropower development.[4]

ELECTRICITY SECTOR OVERVIEW

In 2019, the total installed capacity of Albania stood at 2,275 MW, with 2,162 MW coming from hydropower, 98 MW from thermal power and 15 MW from solar power (Figure 1).[5] In 2019, domestic electricity generation in Albania was almost exclusively from hydropower, with a net generation of 5,208 GWh. Of the total, hydropower accounted for 5,186 GWh (99.6 per cent) and solar power for 22 GWh (0.04 per cent) (Figure 2).[6]

Figure 1. **Installed Electricity Capacity by Source in Albania in 2019 (MW)**



Source: ERE[5]

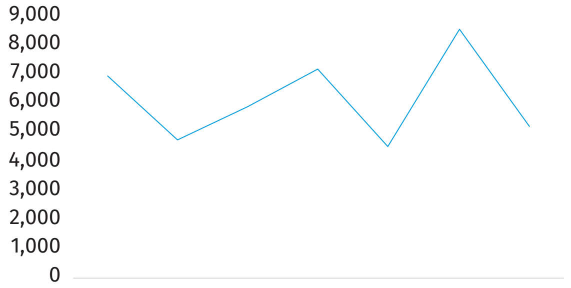
There are three different categories of hydropower plants in Albania. The first category is composed of the three largest hydropower plants, namely, Fierza, Koman and Vau i dejes, with a combined capacity of 1,350 MW. These plants are owned by the Albanian Power Corporation S.A. (KESH), the main state-owned power producer in the country. The second category are large hydropower plants operating on a liberalized market with a total capacity of 252 MW. The third category are the rest of the hydropower plants, which are generally smaller, with a total installed capacity of 560 MW.[5] Albania only has one thermal power plant, the Vlora TPP, owned by KESH, with an installed capacity of 98 MW. However, the plant has never been in operation due to several operational problems, including an issue with its cooling system. Regarding solar power, in 2019 there were eight plants with a total installed capacity of 15 MW.[5]

Figure 2. **Annual Electricity Generation by Source in Albania in 2019 (GWh)**

Source: Instat[6]

Since the electricity sector of Albania is largely dominated by hydropower, electricity generation is significantly dependent on the hydrological conditions and has been fluctuating throughout the years (Figure 3). Thus, in 2019 electricity generation decreased by 39 per cent compared to 2018.[5]

Figure 3. **Total Domestic Electricity Generation in Albania in 2013–2019 (GWh)**

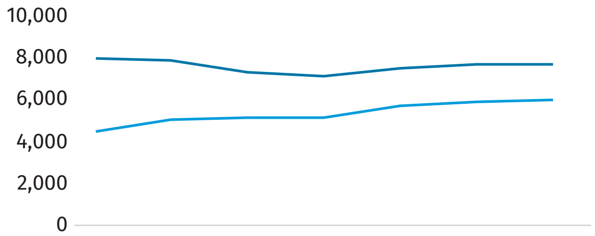


Source: ERE[5]

Albania currently has several planned projects aimed at increasing the installed electricity capacity. Thus, there are several small hydropower (SHP) plants for which construction works are planned to start or which are already in the construction phase. For solar photovoltaics (PV), two large auctions have been conducted. As of the moment of writing of this chapter, one was in the signature phase for a total capacity of 140 MW (Karavasta auction) and the other one was still in the auction phase for a total capacity of 100 MW (Spitalles auction).[7,8] In addition, there are plans to hold auctions for wind generation as well as to revive the Vlora thermal power plant by connecting it to the Trans Adriatic Pipeline (TAP).

In 2019, the net electricity consumption was 5,961 GWh, with total consumption at 7,612 GWh (Figure 4).[5] The level of electricity losses reached almost 22 per cent, representing a significant reduction compared to the previous years, but remained high when compared with the neighbouring countries.[5]

Figure 4. **Electricity Consumption in Albania in 2013–2019 (GWh)**



Source: ERE[5]

The Albanian electricity sector regulator Enti Rregullator i Energjisë (ERE) sets the electricity tariffs for consumers. The tariff for households is approximately 0.11 USD/kWh, while for industrial clients it is at 0.15 USD/kWh.[9,10]

The transmission system is composed of 400 kV, 220 kV, 150 kV and 110 kV lines with the associated substations that serve transmission and international connectivity to Montenegro, Greece and Kosovo. The operator, Operatori i Sistemit të Transmetimit (OST), is entirely state-owned. The level of interconnection in Albania is high compared to the peak load, meaning that Albania can export and import easily to the neighbouring countries.

The distribution company, Operatori i Shpërndarjes së Energjisë Elektrike (OSHEE), is also entirely state-owned. In 2020, OSHEE was unbundled into three companies: Operatori i Sistemit të Shpërndarjes (OSSH), which is responsible for the operation and maintenance of the distribution grid; Furnizuesi i Shërbimit Universal (FSHU), which is the supplier for the clients in the regulated market; and Furnizuesi i Tregut të Lirë (FTL), which is the supplier for the clients in the unregulated market.[11]

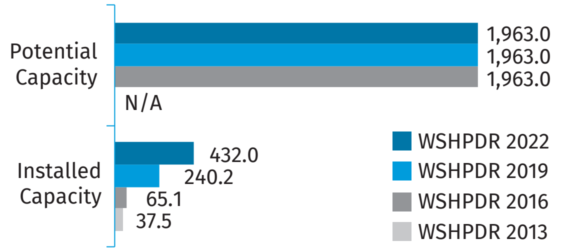
The structure of the electricity market is established through Decision 519 of 13 July 2016 on the approval of the electric power market model.[12] The electricity market in Albania is composed of a regulated and an unregulated market. The vast majority of electricity consumption in the country takes place through the regulated market, for example, through the universal service supplier FSHU, which is part of the OSHEE group. A regulated contract with the public company KESH ensures the bulk of the electricity needs for FSHU at an advantageous price. So far, only high-voltage clients and a few clients at the medium-voltage level have been able to purchase power on the unregulated market. The unregulated market predominantly serves cross-border traders and the utilities to cover the grid losses. The tariffs are set by ERE.

As of the moment of writing of the chapter, there were plans to open ALPEX, a power exchange responsible for the day-ahead and intraday exchanges.[13] In addition, OST is currently setting up a balancing market where balancing products would be purchased following market-based principles.

SMALL HYDROPOWER SECTOR OVERVIEW

In Albania, the definition of SHP is up to 15 MW. In 2019, there were 122 SHP plants with a total capacity of 482 MW (Table 1). Of these, 43 SHP plants with a combined capacity of 217 MW were connected to the transmission grid (110 kV) and 79 plants with a combined capacity of 265 MW were connected to the distribution grid. The installed capacity of SHP plants up to 10 MW totalled 432 MW, with a generation of 489.5 GWh in 2019.[5] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, this represents an 80 per cent increase in installed capacity (Figure 5). This significant increase is a result of the efficient support of the sector, including the existence of a guaranteed buyer offering a good minimal price, which has boosted the construction of new plants in the country. The potential capacity of up to 10 MW is estimated to be 1,963 MW, which suggests that a large share of the potential (78 per cent) has not yet been utilized.[14]

Figure 5. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Albania (MW)**



Source: ERE,[5] *WSHPDR 2016*,[14] *WSHPDR 2013*,[15] *WSHPDR 2019*[16]

Note: Data are for SHP up to 10 MW.

Table 1. **List of Selected Operational SHP Plants in Albania**

Name	*Installed capacity (MW)*	*Operator*
Llapaj	13.6	"Gjo.Spa.POWER" company
Bele 2	11.0	"Alb-Energy" shpk
Lumzi	11.0	MC Inerte Lumzi
Sllabinje	10.4	"Power Elektrik Slabinje" shpk
Dardhe	5.8	"Wenerg" shpk
Topojan 2	5.8	"Euron Energy" shpk
Bele 1	5.0	"Euron Energy" shpk
Orgjost I Ri	4.8	"Energal" shpk
Rrupe	3.6	"Energy partners Al" shpk
Slabinje 2	3.4	"Power Elektrik Slabinje" shpk
Topojan 1	2.9	"Alb-Energy" shpk
Cerunje-2	2.8	"Energy partners Al" shpk
Bishnica 2	2.5	"HEC Bishnica 1,2"shpk
Truen	2.5	"TRUEN" shpk
Cerunje-1	2.3	"Energy partners Al" shpk
Trebisht	1.8	"SA.GLE.Kompani" company
Fterra	1.1	"Hidro Borshi" company
Ternove	0.9	"DITEKO" shpk
Mollai	0.6	"Energii Khaci" company
Kozel	0.5	"E.T.H.H." company

Source: ERE[7]

Currently, SHP plants benefit from preferential treatment as they receive a feed-in tariff (FIT). The off-taker, FTL, which is part of the distribution company OSHEE, is obliged by law to buy all generated electricity at a tariff equivalent to the day-ahead market price in Hungary plus a premium. In 2021, the tariff was set at 60 EUR/MWh (71.7 USD/MWh).[17] The FIT support scheme is valid for a period of 15 years. In addition, SHP plants are not held responsible for imbalances until the end of 2022 or as long as the balancing market is functional.[18]

In previous years, the Energy Ministry of Albania signed a large number of contracts with hydropower developers. However, given that the country is currently seeking to diversify its electricity generation sources away from hydropower, there is no plan to sign further contracts for SHP development.

RENEWABLE ENERGY POLICY

Law 7/2017 on the promotion of the use of energy from renewable sources is the most important piece of legislation on renewable energy in Albania.[18] Under this law, small installations up to 2 MW (3 MW for wind power) are entitled to claim a FIT. Hydropower developers with a plant acceptance certificate received before the end of 2020 can also benefit from the FIT support scheme. The support scheme for installations above 2 MW without a plant acceptance certificate is to be organized through a market-based approach, for example, through auctions for additional renewable energy capacity. The winning bidder would benefit from a sliding feed-in-premium known as a contract for differences. Under this scheme, the developer receives the difference between a prefixed price and the market price for a period of 15 years.

Currently, the target for renewable energy consumption is set at 38 per cent for 2020 and 42 per cent for 2030. A new National Energy and Climate Plan (NECP) is to be published by the end of 2021, which will establish new CO_2 emissions targets as well as new targets for renewable energy generation and consumption. The new NECP is unlikely to have a major impact on SHP, nor is it expected to promote the development of new SHP plants.

The energy regulatory authority ERE, established by the Power Sector Law (Law No. 9072), is responsible for issuing licences for the generation, transmission and distribution of electricity. As per its Rules of Practice and Procedure (Decision No. 21 dated 18 March 2009), ERE guarantees equal treatment in issuing licences and resolving disputes between parties. And under the Rules and Procedures on Certification of Electricity from Renewable Energy Sources, ERE has outlined the procedures for generators to apply for green certificates and approval of project implementation.[16]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Given that there is no intention to further develop new SHP in the country besides the contracts already signed, there are currently no other financial mechanisms available for SHP projects. Nonetheless, SHP can benefit from a FIT according to law 7/2017 on the promotion of the use of energy from renewable sources.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Hydropower generation in Albania is expected to be greatly impacted by climate change.[19] In particular, reduced precipitation, especially in the summer season, may decrease the generation output of hydropower. In addition, changes in the seasonality of river flows, such as more rapid snowmelt due to higher winter temperatures, could reduce the operating time, resulting in decreased generation.

The Government is looking to diversify the country's over-reliance on hydropower to enhance energy security. Since climate change is exacerbating this risk, the diversification of the generation assets becomes even more important.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers for further development of SHP in Albania are as follows:

- Current effort to diversify from the almost exclusive reliance on hydropower by encouraging the increase of other sources of renewable energy, such as wind power and solar PV. Such diversification could reduce the impulse for new SHP development.
- Social resistance to new hydropower developments, notably for the Vjosa River.[20] In 2019, the Prime Minister announced the Government's decision to cancel the construction of all hydropower plants on the Vjosa River.[21,22] This generalized resistance might negatively impact the further development of SHP in Albania. Among the factors contributing to this resistance are: infringement on property rights of citizens living in the vicinity of the projects, effects on water quality, potential degradation of the ecosystem, loss of species diversity and genetic diversity, among others.

While in the light of the above limiting factors further SHP development in the country appears unlikely, there, nonetheless, remains a significant untapped potential, which can be considered as the key enabling factor.

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Bosnia and Herzegovina

Hamid Mehinović and Esmina Šahić, Westport Consulting

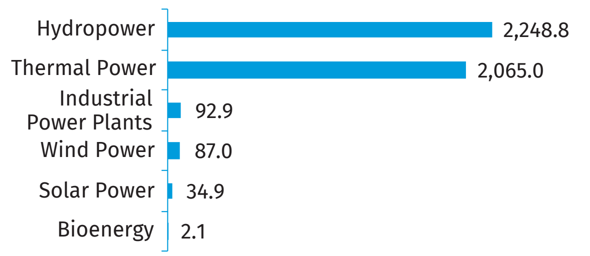
KEY FACTS

Population	3,280,815 (2020)[1]
Area	51,197 km^2 [2]
Topography	Bosnia and Herzegovina (BiH) shares a 932-kilometre border with Croatia to the north and south-west, a 357-kilometre border with Serbia to the east and a 249-kilometre border with Montenegro to the south-east. It borders the Adriatic Sea along its 20-kilometre coastline. The country's territory consists of valleys and mountains, which measure up to 2,386 metres in height, and its lowest altitude is 0 metres. The country is mainly hilly to mountainous, with an average altitude of 500 metres. Of the total land area, 5 per cent is lowlands, 24 per cent is hills, 42 per cent is mountains and 29 per cent is a karst region.[3]
Climate	The country consists of several different climate zones: 1) alpine climate in the mountain regions, 2) continental climate in the northern Pannonia lowlands along the Sava River and foothills, and 3) Mediterranean climate in the coastal and lowland regions of the Herzegovina region in the south and south-east. Due to the temperature characteristics, the territory of BiH is divided into three temperature zones: warm, moderate and cold. The warm zone corresponds to the Adriatic coast and lowland Herzegovina with mean winter temperatures of 5 °C and summer temperatures reaching 40 °C. In the moderate hilly areas, temperatures range from 0 °C in winter and 35 °C in summer. The mountainous, cold regions reach below 0 °C.[4]
Climate Change	The climate change has a significant impact in the country. Frequent flooding, severe and intense rain and drought are only some of the symptoms that impact the tourism and energy sector (particularly, hydropower) in BiH, as well as agriculture, human health, biodiversity and water resources.[4]
Rain Pattern	Annual precipitation ranges from 800 mm in the north along the Sava River to 2,000 mm in the central and south-eastern mountainous regions. Maximum rainfall occurs mostly at the end of autumn or beginning of winter, mostly in November or December.[4]
Hydrology	The waters of the country are made of the Adriatic Sea basin and the Danube River basin. The Sava River subbasin is the second largest subbasin of the Danube River basin, with approximately 40 per cent lying in BiH, whereas the rest of the watershed is shared by Croatia, Serbia and Slovenia.[5]

ELECTRICITY SECTOR OVERVIEW

The total installed capacity of Bosnia and Herzegovina (BiH) in 2020 amounted to 4,530.6 MW (Figure 1).[6] Renewable energy has been used for power generation in the country since the 1950s. While hydropower has dominated among renewable energy sources, since 2010 the relevant BiH institutions started to actively promote the use of other renewable energy technologies as well, with a focus on solar photovoltaics (PV), wind power and biomass. In 2019, the first two wind farms connected to the transmission system, Mesihovina and Jelovača, injected into the network 254 GWh. In 2020, an additional wind farm was connected to the transmission system, Podvelezje, with a total installed capacity of 48 MW.[7]

Figure 1. **Installed Electricity Capacity by Source in Bosnia and Herzegovina in 2020 (MW)**

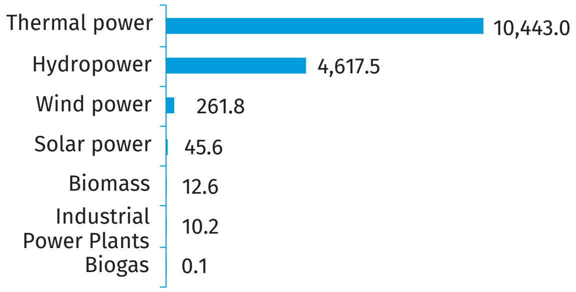


Source: SERC[6]

In 2020, electricity generation reached 15,391 GWh (Figure 2), which was 4 per cent less than in 2019 and 14 per cent less than 2018.[6] In 2020, small-scale renewable energy generation recorded a 26 per cent decrease from 2019 amounting to 399 GWh, much of which was due to a drop in small hydropower (SHP) generation.[6]

In 2020, BiH registered an almost 36 per cent share of renewable energy sources in its energy mix, which was behind its 2018 target of 38 per cent.[7] A new target for 2030 was set within the National Energy and Climate Plan (NECP) by the Ministry of Foreign Trade and Economic Relations (MOFTER) and entity Energy Ministries.

Figure 2. **Annual Electricity Generation by Source in Bosnia and Herzegovina in 2020 (GWh)**



Source: SERC[6]

BiH consists of two administrative entities, Federation of Bosnia and Herzegovina (FBiH) and Republika Srpska (RS). Additionally, the Brčko District, a self-governing administrative unit, remains under international supervision. Under the Constitution of BiH, the energy sector is managed by each administrative entity. In FBiH, the main institutions are the Federal Ministry of Energy, Mining and Industry (FMERI) and the Federation Electricity Regulatory Commission (FERK). The electricity sector is governed by the Law on Electricity and Law on Renewable Energy Sources, both adopted in 2013. The key institutions in RS include the MOFTER, State Energy Regulatory Authority (SERC), Transmission Company (Elektroprenos BiH) and Independent System Operator BiH (ISO BiH). Electricity generation, distribution system operation and supply of electricity are governed by administrative entity legislation respectively in FBiH and RS, as well as by the Brčko District. The local Government of the Brčko District is responsible for the implementation of the Electricity Law of the District, adopted initially in 2004 and amended in 2013.

The country has a 100 per cent electrification rate. The electricity sector in BiH began the process of liberalization in 2015, but to date no electricity wholesale market has been established and consequently no competitive retail market exists.[7]

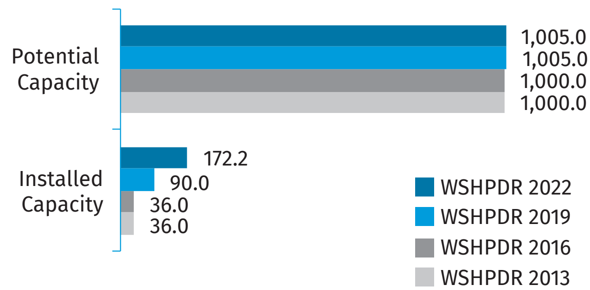
The principal means for regulating the electricity sector is through a licensing regime. Electricity-related licences in BiH are issued by the State Electricity Regulatory Commission (DERK), FERK in FBiH or the Regulatory Commission for Energy in RS (RERS), depending on the jurisdiction. DERK is responsible for regulating tariffs for the services of Elektroprenos BiH, operation of ISO BiH, ancillary services, non-qualified customers belonging to the category of households in the Brčko District and electricity distribution services in the Brčko District as well as for determining the electricity costs of the default supplier in the Brčko District. FERK and RERS are responsible for regulating tariffs for the supply of electricity to non-eligible (tariff) customers and tariffs for distribution system users.[8]

In FBiH and RS, fixed electricity tariffs are calculated by adding technology-specific premiums to a reference price. In FBiH, technology-specific conversion factors are multiplied by the reference price of 0.081 BAM/kWh (0.049 USD/kWh). In RS, absolute determined premiums are added to the reference price of 0.0541 BAM/kWh (0.033 USD/kWh). RS also offers a premium for electricity produced from renewable energy sources, regardless of whether the energy generated is either sold directly to the market or is used for own consumption. Tariffs are granted for 15 years in RS and for 12 years in FBiH.[9]

SMALL HYDROPOWER SECTOR OVERVIEW

In BiH, SHP plants are considered as those up to 10 MW in capacity and are often built on small rivers, streams and canals. In 2020, installed capacity of SHP plants amounted to 172.2 MW (Table 1).[6] This is a significant increase since the *World Small Hydropower Development Report* (*WSHPDR) 2019* when only 90 MW of installed capacity was recorded, with the difference being due to access to more accurate data and continued growth of the sector (Figure 3). No new studies on SHP potential have been recorded since the *WSHPDR 2019*. Generation from SHP in 2020 (341 GWh) was significantly lower than that in 2019 (498 GWh) due to poor hydrological conditions.[6]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Bosnia and Herzegovina (MW)**



Source: Waters of Bosnia and Herzegovina,[10] Gvero,[11] *WSHPDR 2013*,[12] *WSHPDR 2016*,[13] *WSHPDR 2019*[14]

Table 1. **List of Selected Operational Small Hydropower Plants in Bosnia and Herzegovina**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Bočac 2	Bočac	10.00	–	ZP Hidroelektrane na Vrbasu -Bočac 2 a.d.	2018
Podivič	Istocno Sarajevo, Trnovo	0.10	–	Buk d.o.o.	2018
Do	Berkovići	2.00	–	Strajko d.o.o.	2016
Ustiprača	Ustiprača	6.80	–	Hidroinvest d.o.o.	2015
Mesići-Nova	Rogatica	2.00	Reservoir	ERS-MP a.d., ZP Elektrodistribucija a.d.	2015
Žiraja	Bijelo Bučije	0.41	–	Mega elektrik a.d.	2013

Name	Location	Capacity (MW)	Plant type	Operator	Launch year
Novakovići	Kneževo	5.77	–	EHE društvo za proizvodnju, razvoj i trgovinu d.o.o	2012
SHE Sućeska R-S-2	Strgačina	1.10	–	ERS male hidroelektrane d.o.o. (Energy Zotter Bau)	2012
Kaljani	Prača	1.45	–	Energonova d.d.	2011
Bistrica B-5ª	Dobro Polje	3.87	–	Bobar taubinger elektrik d.o.o. (Anton Kittel Muhle Gmbh)	2010
Sućeska R-S-1	Strgačina	1.80	–	ERS male hidroelektrane d.o.o. (Energy Zotter Bau)	2009
Divič	Kruševo Brdo	2.28	–	Eling male hidroelektrane d.o.o.	2005
Bogatići Nova	Trnovo	10.00	Reservoir	JP Elektroprivreda BiH d.d. (28%), Elektroprivreda RS (72%)	1947
Bogatići Nova	Trnovo	9.40	–	JP Elektroprivreda BiH d.d. (28%), Elektroprivreda RS (72%)	1947
Trebinje II	–	8.00	Run-of-river	ZP Hidroelektrane na Trebišnjici a.d. Trebinje	–

Source: Waters of Bosnia and Herzegovina[11]

As of 2021, there were 115 SHP plants in operation and 341 under various stages of planning and construction (Table 2).[11] For example, the Neretvica SHP plant project consists of 15 plants with an overall capacity of 24.5 MW and a total project cost of EUR 50 million (USD 59 million. The first phase of the project includes four SHP plants with a total of 9.4 MW of installed capacity.[15]

Table 2. **List of Selected Planned Small Hydropower Projects in Bosnia and Herzegovina**

Name	Location	Capacity (MW)	Developer	Stage of development
Doboj	Republika Srpska	9.80	Technor Hydro 2 AS, Norveška	Concession agreement terminated
Kruševo	Bioštica, Olovo	9.75	JP Elektroprivreda BiH d.d.	Planned
Volujak	Gračanica	4.50	MM Energi d.o.o.	Environmental permits issued
Bistrica B-4	Foča	2.90	Bobar elektronik d.o.o. Brod na Drini	Concession agreement terminated
Lakat	–	1.70	Čalik enterji(Turska)	Preliminary design

Source: Waters of Bosnia and Herzegovina[11]

Although there has been a rapid rise of SHP in the country, there has also been a pushback from environmental groups against further SHP development in the Balkans. This is due to the larger concern that 817 hydropower plants, representing 49 per cent of all hydropower plants in the Balkan region, lie in protected areas.[16] Because of recent policy developments, it is unlikely that developers will be seeking to develop in the near future.

RENEWABLE ENERGY POLICY

Recently, relevant institutions in BiH, such as Ministry of Foreign Trade and Economic Relations of BiH, Ministry of Energy, Mining and Industry of FBiH, Ministry of Industry, Energy and Mining of RRS and Government of the Brčko District, started to engage in active renewable promotion. The National Renewable Action Plan (NREAP) of BiH, which was developed based on the FBiH and RS Renewable Energy Action Plans, set a target of a 40 per cent share of renewable energy sources in final energy consumption and a 10 per cent share in transport by 2020. The Framework Energy Strategy of BiH Until 2035 is aimed at prioritizing the key energy strategies for the years to come. Under this framework, the country aims to increase the share of renewable energy to 40 per cent with a focus on increasing deployment in the electricity sector.[17]

BiH is a Contracting Party to the Energy Community Treaty, which imposes clear obligations and deadlines to adopt, reform and implement changes related to the energy sector. These include market development and competitive landscape as well as environmental protection.

The legal and regulatory authority framework in BiH electricity sector is complex. At the state level, there are three main laws governing the electricity sector all adopted in 2004: Law on Transmission, Regulator and Electricity System Operator; Law on Establishment of Transmission Company; and Law on Establishment of the Independent System Operator.

The main support scheme for the production of electricity from renewable energy sources in BiH is a FIT. RS promotes the power production from renewable energy sources mainly through a FIT and feed-in premium. Policy makers in BiH have pushed for a reform of the support system to curb its rising cost, questioning the use of FIT in particular. Many in the Government consider FIT to be an effective but not a cost-efficient instrument for renewable energy support and that the use of the FIT is inconsistent with the goal of renewable energy market integration. Instead, large-scale renewable energy plants should be encouraged to sell their electricity to the wholesale market, with any support being additional to market revenues. The underlying rationale for this policy is to enhance the operational efficiency of renewable energy plants via an improved match of demand and supply.

In FBiH, tariffs are regulated by the Renewable Energy Sources Law of FBiH and special decrees and rulebooks. The plant operators need to obtain the status of a privileged power producer to acquire the right to a price support for the generated electricity under the legal requirements. After having concluded a power purchase agreement with the plant operator, the operator for renewable energy sources and coefficient cogeneration (RES Operator) is legally obliged to buy the total amount of electric energy from privileged producers at an incentive price. The amount of the feed-in tariff (FIT) is determined in the annex of the Decision on the determination of the guaranteed prices for electricity from renewable energy sources and efficient cogeneration and depends on the type of technology and the capacity of the power plant.[18]

In RS, tariffs are regulated by the Energy Law of RS, Electricity Law of RS and above all the Renewable Energy Sources Law of RS; there are also special decrees and rulebooks. Firstly, the plant operator needs to obtain a renewable energy source certificate and a decision on the right to support by applying to the Energy Regulator (Art. 12 of Electricity Law). The Support Scheme Operator (Art. 13 of Renewable Energy Sources Law RS) concludes a power purchase agreement at a guaranteed price. The amount of the FIT is determined in the Decision on the amount of the guaranteed prices and premium prices for electricity produced from renewable sources and efficient cogeneration and depends on the type of technology and the capacity of the power plant. The FIT is financed by an incentive fee that the final consumer is obliged to pay on the amount of consumed electricity (Art. 30 of Renewable Energy Sources Law RS).[19]

In both administrative entities, renewable energy developers enjoy other incentives, such as priority in dispatch. Both entities prioritize grid connection for renewable energy source operators. FBiH and RS both also offer other incentives for foreign investors, such as customs-free imported materials in FBiH and corporate tax exemption in RS.

In FBiH, the connection of power plants from renewable energy sources to the grid is mainly regulated by the general legislation on energy (Art. 28, § 1 of Renewable Energy Sources Law FBiH). In RS, the connection of power plants from renewable energy sources to the grid is regulated by the general legislation on energy (Electricity Law of RS, Renewable Energy Sources Law of RS), General Conditions for Delivery and Supply of Electricity, Rule Book on Methodology for Determination of the Fee for Connection to the Distribution Network and Rule Book on Conditions for Connection of the Facilities to the Electric Distribution Network of the RS. In both entities, the grid operators generally provide non-discriminatory access to the grid and renewable energy producers are given priority to connect to the grid.[19]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Due to the pressure of environmental activists, the House of Representative of FBiH adopted the Declaration on Protection of Rivers in February 2021 with the aim of completely banning the construction of SHP plants in FBiH.[19] In order for the ban to become effective, FBiH needs to amend the existing legislation. The FBiH House of Representatives gave a three-month deadline to the FBiH Government to analyse and draft the amendments to the current legislation needed for the implementation of the Declaration and ban. On top of this, the Government rejected a proposal in April 2021 that would amend the Law on the Use of Renewable Energy Sources and Efficient Cogeneration to allow 17 SHP plants to continue benefiting from a subsidy scheme until the end of their concession agreements.[20]

Although the construction of SHP plants has not been banned in RS, the entity has enacted a set of measures that seem to have a similar goal. The RS National Assembly instructed the RS Government to draft a proposal of measures for the review of all concession agreements and the status of activities envisaged by the latter to temporarily suspend the initiatives for construction of new SHP plants until the finalization of the aforementioned review, and to reassess and amend the incentives system for electricity produced from SHP plants.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Most SHP projects are financed by commercial bank loans and guarantees are topped up by the companies' own resources. Pledge registries, business registries and land registries in some countries sometimes contain information on loans taken for the construction of hydropower plants. Three greenfield projects identified in BiH have confirmed financing from multilateral development banks: Vranduk with financing from the European Bank for Reconstruction and Development (EBRD) and European Investment Bank (EIB) signed; the Brestovni Potok plant financed by the EBRD through an unidentified financial intermediary; and the Kraljuščica 1 plant near Konjic, also financed by the EBRD through UniCredit as a financial intermediary.[21]

There is also some interest from Chinese banks in BiH, however there are no commitments on paper yet. The project sponsor of the Ulog project on the Upper Neretva, the Energy Financing Team (EFT), has stated in June 2012 that it is in negotiations with the China Development Bank regarding financing.[22] Chinese companies have also expressed interest in the controversial Dabar hydropower plant, part of the Gornji Horizonti complex, which would move water from the Neretva attachment to the Trebišnjica, as well as the Buk Bijela project on the River Drina and the lesser known Trn and Laktaši plants on the River Vrbas near Banja Luka.[21]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change is expected to exacerbate problems related to low river flows. The expected summer precipitation decreases in inland areas could lead to a fall in the production of hydropower, which could also jeopardize energy security and electricity exports. Droughts have contributed to reductions in the production of hydropower. This reduction can be compensated for through thermal power generation or imports, although neither is economically viable or environmentally friendly. Furthermore, the climate crisis is expected to increase the risk of damage due to more frequent floods as well as lower the quality of potable water.[22]

Planned outputs and activities of the Climate Change Adaptation and Low-Emission Development Strategy, adopted by the council of ministers in October 2013 that are related to hydropower include:

- Improved guidelines for the construction of hydropower plants, considering the potential impact of climate change (technical assistance and capacity building programme to develop guidelines, followed by training and awareness raising);
- Improved and functioning licence control for hydropower plants (revised regulations, monitoring and enforcement programme);
- Hydrological models for various climate scenarios need to be developed to support both risk management strategies and mitigation measures.[23]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The following points summarize the main barriers to SHP development in BiH that have been identified:

- Negative environmental impacts on protected areas due to poor construction practices including water pollution, waste disposal, soil erosion impacts and habitat encroachment;
- Lack of adequate economic incentives;
- Lack of adequate consultation with local population;
- Recent adoption of the Declaration on Protection of Rivers with the aim to ban construction of SHP in FBiH;
- Strong negative reputation of SHP in the country due to perceived harmful practices.

The following points summarize the main enablers that have been identified:

- Remaining and vast undeveloped potential in the country.

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Croatia

Danilo Fras, Consultant; Goran Vasilić, Energy Eastern Europe HP GmbH

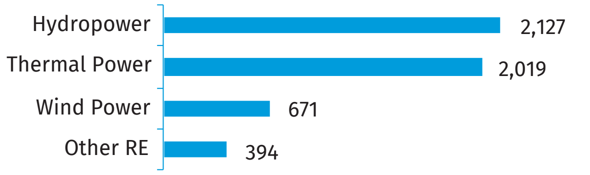
KEY FACTS

Population	4,058,165 (2019) [1]
Area	56,594 km² [2]
Topography	The topography of Croatia is divided into three distinct areas: 1) the lowland basin between the Sava and Drava Rivers and along the border with Hungary (the Pannonian Plain) in the east and north-west; 2) the mountainous karst region of the Dinaric Range in the centre and 3) the littoral region along the Adriatic coast, which runs from the Istria County in the north through Dalmatia to the Prevlaka peninsula in the south. Approximately one quarter of the territory of Croatia is arable. The highest peak is Mount Dinara at 1,831 metres, located on the border between Croatia and Bosnia and Herzegovina.[3]
Climate	The climate of Croatia varies across regions. A continental climate predominates on the Pannonian Plain and a Mediterranean one along the Adriatic coast, while variations of those two climates are present in the Central Belt of the Dinaric Mountain barrier. The coastline is marked by frequent strong winds — the colder Bura as well as the warmer Jugo.[4]
Climate Change	The average annual air temperatures in Croatia in 2019 exceeded the multi-annual average (1981–2010) by 0.7 °C (Komiža) to 1.9 °C (Gospić and Zagreb-Grič). At the Zagreb-Grič station, the average annual air temperature in 2019 was 14.2 °C, compared with the 1981–2010 average of 12.3 °C, making the 2019 annual average the warmest observed at the station since the beginning of meteorological observations in 1862.[5] The Regional Climate Model for Croatia indicates a further increase in air temperatures in the coming decades. Thus, for the period 2011–2040, the temperature in Croatia is expected to increase by 0.6 °C in winter and by 1 °C in summer. For the period 2041–2070, the model projects an increase of 2 °C in the continental part of the country, 1.6 °C in the south and 3 °C in the coastal region. Precipitation is also expected to decline in the coming decades but the patterns of change are projected to vary regionally and across seasons. Furthermore, many projections foresee a future climate with winters wetter in the north and drier in the south.[6]
Rain Pattern	The precipitation regime in Croatia reflects the diversity of topographic areas and climactic zones and the influence of the mountain barrier between them. While in the Pannonian Plain average annual precipitation reaches 800–1,300 mm per year, in the coastal region it is only approximately 700–800 mm. In the Gorska Hrvatska region, average annual precipitation ranges from 1,300 mm to 3.500 mm.[7] Areas receiving the least annual precipitation include the small, remote Croatian archipelago of Palagruža in the middle of the Adriatic Sea (304 mm) and eastern Slavonia and Baranja (Osijek, 650 mm).[8,9] An analysis of annual precipitation in 2019 indicates that precipitation values in Croatia across all surveyed stations were within the range of 103–143 per cent of the 1981–2010 average.[5]
Hydrology	The main hydrological divisions of Croatia are the Black Sea catchment basin and the Adriatic catchment basin. The Black Sea basin comprises approximately 62 per cent of the country's territory. It can be further subdivided into the Danube and the Drava basins lying within the Pannonian Plain and the Sava River basin in the Dinaric karst, which also includes its tributaries the Kupa, Bosut and Una Rivers. The Danube is the major navigable river of Croatia. Meanwhile, the Adriatic basin comprises 38 per cent of the territory of the country, and includes the Cetina, Krka, Zrmanja and Rjecina Rivers.[10,11] Major lakes in Croatia include Lake Vransko (30.7 km²), as well as the artificial reservoirs Lake Dubrava (17.1 km²) and Lake Varaždin (10.1 km²) on the Drava River and Lake Peruća (13 km²) on the Cetina River.[11]

ELECTRICITY SECTOR OVERVIEW

The total installed capacity of power plants in Croatia at the end of 2019 was 5,211 MW, with hydropower providing 2,127 MW (41 per cent), thermal power 2,019 MW (39 per cent), wind power 671 MW (13 per cent) and other renewable energy sources a total of 394 MW (8 per cent) (Figure 1). These figures exclude the installed capacity of the Krško nuclear power plant, located on the territory of Slovenia, of which Croatia owns a 50 per cent share.[12,13] Wind power in Croatia has been undergoing a rapid expansion in the last decade, by April 2021 reaching an installed capacity of 738.25 MW, up from 26.8 MW in 2009.[13,14]

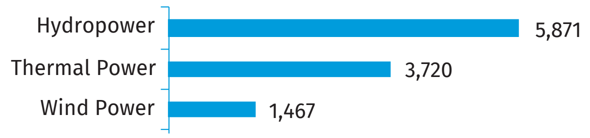
Figure 1. **Installed Electricity Capacity by Source in Croatia in 2019 (MW)**



Source: HERA[12]

Total generation of electricity in 2019 was 12,005 GWh, of which hydropower provided 5,871 GWh (49 per cent), thermal power 3,720 GWh (31 per cent), wind power 1,467 GWh (12 per cent), and other renewable energy sources 947 GWh (8 per cent) (Figure 2).[12]

Figure 2. **Annual Electricity Generation by Source in Croatia in 2019 (GWh)**



Source: HERA[12]

Access to electricity in Croatia is 100 per cent.[15] Total annual consumption of electricity realized in the transmission network in 2019 was 16,821 GWh, with system peak load at 3,038 MW and a total of 22,198 GWh of electricity transmitted. Total transmission losses were 387.9 GWh (approximately 1.8 per cent of all transmitted electricity). Imports, including electricity produced by the Krško nuclear power plant, totalled 6,163 GWh, amounting to 35.6 per cent of total consumption.[12,13]

The electricity sector of Croatia has been liberalized but remains dominated by the state-owned company Hrvatska Elektroprivreda (HEP), especially in the area of large hydropower and thermal power. The national electricity market of Croatia is fully aligned with the European Union (EU) directives governed by EU regulations. Croatia has adopted the independent transmission operator (ITO) model of market unbundling, with the Croatian Transmission System Operator (HOPS) being separate from the state-owned utility HEP, which owns the transmission network. Authorities of major importance for the energy sector include the Ministry of Environmental Protection and Energy, in charge of developing energy policy; the Croatian Energy Regulatory Agency (HERA), an independent public institution in charge of regulating energy activities; and the Croatian Energy Market Operator (HROTE), which organizes the electricity and gas markets as a public service under the supervision of HERA.[16]

The structure of the electricity market in Croatia is outlined in the Energy Act and the Electricity Market Act. In fact, there are two distinct electricity markets in the country. The initial energy market model was a bilateral one in which electricity trading was carried out based on bilateral contracts between market participants. The Rules of Organizing the Electricity Market of 2015 introduced the concept of balancing groups, enabling portfolio optimization of subjects bundled into a single balance group. The second electricity market is regulated by the Croatian Power Exchange Ltd. (CROPEX), which was created in 2016 and in 2018 was merged with the Slovenian stock market. Any producer, supplier, energy trader or eligible customer is a market participant in the Croatian electricity market. For performing energy-related activities, a licence must be obtained from HERA and an Electricity Market Participation Agreement must be signed with HROTE.[17,18] The Integrated National Energy and Climate Plan of Croatia for the period 2020–2030 with an outlook until 2050, adopted in December 2019, aims to strengthen the country's energy market and to integrate it completely with that of the EU and the international energy markets. Regulatory activities are to be steered towards simplifying market access and allowing equal and non-discriminatory access to the grid infrastructure.[19]

The average electricity price including all taxes, levies and VAT for an annual consumption of 2,500–5,000 kWh for household end users in the second half of 2020 was 0.131 EUR/kWh (0.16 USD/kWh) while the average electricity price for non-household consumers with an annual consumption of 500–2,000 MWh, excluding all recoverable taxes and levies, was approximately 0.102 EUR/kWh (0.12 USD/kWh).[20,21] The prices generally vary with the amount of electricity consumed, making it cheaper for larger consumers such as business and industry. For eligible producers taking part in the incentive system for renewable energy under the Renewable Energy Source and High-Efficiency Cogeneration Act, the weighted average price of electricity paid in 2019 was approximately 2.5 times higher than the annual average electricity price on the day-ahead market on the CROPEX electricity exchange (0.37 HRK/kWh (0.06 USD/kWh)).[12]

SMALL HYDROPOWER SECTOR OVERVIEW

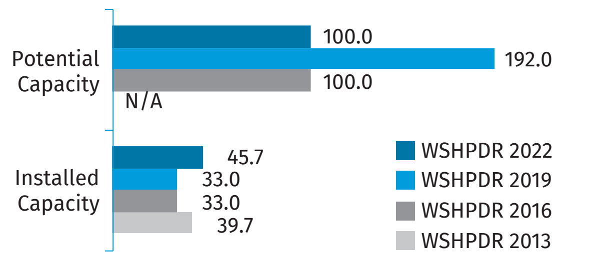
Small hydropower (SHP) plants are defined in Croatia as plants having an installed capacity of less than 10 MW, as per the EU standard.

The total natural hydropower generation potential in the Republic of Croatia is approximately 21.3 TWh, while the technical hydropower generation potential is approximately 12.4 TWh. Currently, around 49 per cent of the technical hydropower potential is utilized, which means that the remaining available technical hydropower potential is approximately 6.2 TWh. Approximately 8 per cent of the total technical hydropower potential is accounted for by the potential of small watercourses (514.92 GWh/year).[22]

The technical potential capacity of SHP plants in Croatia (not considering environmental constraints) is approximately 350 MW, while the most recent data suggest that the realistically achievable potential is 100 MW, according to the conclusions of the “Small hydropower plants in Croatia” symposium held in 2015.[23] The possibility of using a large part of the currently-unused potential will depend on the harmonization of the interests of Croatia and neighbouring countries. Part of the hydropower potential will likely remain unused due to ecological and other constraints.

As of 2019, there were 39 SHP plants operational in Croatia with a total installed capacity of 45.68 MW.[24] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed SHP capacity increased by nearly 39 per cent; however, this increase is primarily due to more accurate data on operational SHP plants becoming available (Figure 3, Table 1). Of the operational SHP plants, 14 with a total installed capacity of 5.9 MW were enrolled in the incentive scheme for renewable energy sources and two additional SHP contracts with a total installed capacity of approximately 0.8 MW were pending as of 2020.[12,25] SHP projects previously considered for development include the Dale SHP plant (6.4 MW), TE-TO Zagreb SHP plant (84.3 kW) and four SHP plants on the Sava River near Zagreb (Jarun, Šanci, Petruševec and Ivanja Reka) with a total capacity of 40 MW.[26,27] As of 2019, there were plans in Croatia for at least 29 additional SHP projects with a total planned installed capacity of 27.64 MW, in various stages of approval (Table 2).[24]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Croatia (MW)**



Source: Croatian Water Institute for Water Management,[24] *WSHPDR 2013*,[28] *WSHPDR 2016*,[29] *WSHPDR 2019*[30]

Table 1. **List of Selected Operational Small Hydropower Plants in Croatia**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Pamučna industrija Duga Resa	Mrežnica River	1.10	Run-of-river	Duga Resa Cotton Industry	1884
Jaruga	Krka River	5.60	Run-of-river	HEP	1903
Ozalj 1	Kupa River	3.54	Run-of-river	HEP	1908
Roški Slap	Krka River	1.77	Run-of-river	Hidro-Watt LLC	1909
Zeleni Vir	Curak watercourse	2.00	Run-of-river	HEP	1922
Ozalj 2	Kupa River	2.20	Run-of-river	HEP	1952
Zavrelje	Zavrelje source	2.10	Run-of-river	HEP	1953
Fužine	Ličanka River	6.50	Pumped storage	HEP	1957
Varaždin PS	Drava River	0.64	Run-of-river	HEP	1976
Golubić	Butižnica River	7.50	Run-of-river	HEP	1981
Čakovec 1	Drava River	1.10	Run-of-river	HEP	1982
Čakovec 2	Drava River	0.34	Run-of-river	HEP	1983
Krčić	Krčić watercourse	0.36	Run-of-river	HEP	1988
Dubrava 1	Drava River	1.10	Run-of-river	HEP	1989
Dubrava 2 and 3	Drava River	0.68	Run-of-river	HEP	1991
Bujan	Kupčina River	0.05	Run-of-river	Josip Bujan	1995
Lepenica	Lepenica accumulation	1.20	Reversible	HEP	1996
Mataković 1 and 2	Mrežnica River	0.02	Run-of-river	Obrt Mataković, metal machining	2007
Pleternica	Orljava River	0.23	Run-of-river	Pleternica SHP LLC	2012
Pranjčevići	Cetina River	1.31	Run-of-river	HEP	2017

Source: Croatian Water Institute for Water Management[24]

Table 2. **List of Selected Planned Small Hydropower Projects in Croatia**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Developer*
Gomirsko Vrbovsko	Dobra River	0.22	–	Nova energija LLC
Korana 1	Korana River	0.35	Run-of-river	Ekološki sistemi LLC
Odeta 1	Korana River	1.25	Run-of-river	Odeta LLC
Odeta 2	Mrežnica River	0.42	Run-of-river	Odeta LLC
Požega	Orljava River	0.12	Run-of-river	Pleternica SHP LLC

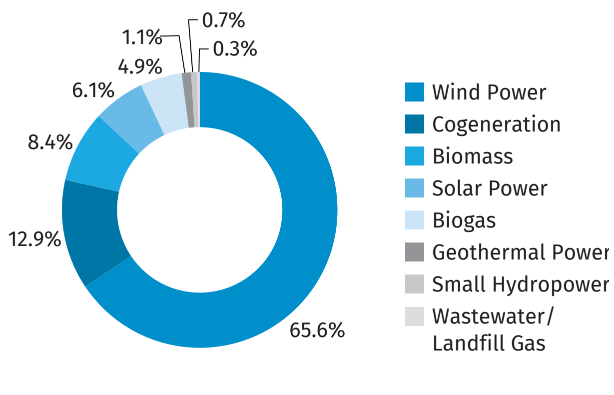
Source: Croatian Water Institute for Water Management[24]

RENEWABLE ENERGY POLICY

The Integrated National Energy and Climate Plan of Croatia for the period 2020–2030 with an outlook until 2050 was adopted in December 2019 under the mandate of the Energy Act.[19] Of the targets addressed in this Plan, decarbonization is the most significant. The two key components of the decarbonization target are a reduction in greenhouse gas emissions (at least 43 per cent for the European Emissions Trading System (ETS) sector and at least 7 per cent for the non-ETS sector) and an increased share of renewable energy sources in final energy consumption (63.8 per cent of electricity consumption, 36.4 per cent of gross final energy consumption and 13.2 per cent in the transport sector) by 2030. According to the Plan, renewable energy is expected to account for 79 per cent of all produced energy by 2050. All non-renewable energy sources, including thermal power and public and industrial cogeneration, are expected to decrease their production, with their combined share decreasing from 37.1 per cent in 2010 to 27.8 per cent in 2030 and to 21 per cent in 2050.[19]

As the share of renewable sources in the country's energy mix and the financial viability of renewable energy projects increase, the Plan aims to gradually decrease incentives paid to renewable energy producers, with the end goal of reaching a point where incentives will no longer be necessary. At the same time, continued support for the development of renewable energy sources will be provided by unburdening such projects from certain taxes and levies, removing administrative obstacles, simplifying permit issuance procedures and setting guidelines, recommendations and best practices for projects in urban areas. The national Government as well as local and regional authorities will be expected to contribute to the project's development by preparing necessary studies and documentation.[31]

Figure 4. **Share of Renewable Energy Sources in the Incentive System of Croatia in 2019 (%)**



Source: HERA[12]

The current tariff system incentivizing renewable energy sources, which reduced support for wind and solar power plants, was introduced in 2014. Under the tariff system for production of electricity from renewable energy sources and cogeneration, renewable energy producers who have obtained the status of a privileged producer and subsequently won a public tender carried out by HROTE receive a premium on the base tariff for a period of 14 years.[32] The share of each renewable source among power plants currently enrolled in the incentive system is displayed in Figure 4, with tariffs showed in Table 3.

Table 3. **Premium Tariff for Renewable Energy in Croatia**

Energy type	*Capacity (MW)*	*Incentive price (USD/kWh)*
Hydropower	<0.3	0.17
	0.3–2	0.15
	2–5	0.14
Wind power	>5	RC
Biomass	<0.3	0.21
	0.3–2	0.20
	2–5	0.19
	>5	RC
Geothermal		0.19
Biogas	<0.3	0.22
	0.3–2	0.20
	2–5	0.19
	>5	RC

Source: HROTE[32]

Note: RC stands for reference price; for each accounting period, plants that have the incentive price of RC will be paid the amount of currently valid RC.

On 1 January 2016, a new Law on Renewable Energy Sources and High-Efficiency Cogeneration came into force and introduced a premium tariff support scheme for these technologies. The Law aims for the efficient use of energy and reduction of the impact of fossil fuels on the environment. It represents the first comprehensive codification of provisions concerning the planning and promotion of renewable energy sources in the country.[33] The Law elaborates in detail the method and conditions for the implementation of new incentive models consisting of market premiums and buy-offs at a guaranteed price, setting maximum reference values and maximum guaranteed buy-off prices, contracting procedures and setting incentive quotas.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The legal framework regulating activities for investing in SHP in Croatia includes the following acts:

- Act on the Regulation of Energy Activities (Official Gazette Nos. 120/12 and 68/18);
- Energy Act (Official Gazette Nos. 120/12, 14/14, 102/15 and 68/18);
- Electricity Market Act (Official Gazette Nos. 22/13, 102/15 and 68/18);
- Law on Renewable Energy Sources and High-Efficiency

Cogeneration (Official Gazette Nos. 100/15 and 111/18);
- General Administrative Procedure Act (Official Gazette No. 47/09); and
- Other ordinances (rules) and decisions correlated to the above-mentioned acts.[34]

Permits required for construction and operation of SHP plants in Croatia include:
- An environmental permit in the case of SHP plants above 5 MW, predicated on a decision by the Ministry of Environmental Protection, Physical Planning and Construction on the need for an environmental impact assessment;
- A building permit allowing the construction of the facility;
- An energy permit, which also applies to all facilities that exploit natural resources, with the exception of solar power plants integrated into rooftops and walls of buildings.[34]

COST OF SMALL HYDROPOWER DEVELOPMENT

Based on the cost of hydropower plants commissioned in recent years, the specific investment cost of SHP development in Croatia can be estimated to range between EUR 2.2 million and EUR 3.5 million (USD 2.67–4.24 million) per installed MW.

In 2014, the Pleternica SHP plant was commissioned, with an installed capacity of 220 kW. The specific investment costs of the project stood at approximately EUR 3.5 million (USD 4.24 million) per installed MW.[35] The Velika Šuma SHP plant near the town of Umag was put into trial operation in 2016, the first in Croatia to be built on a water supply system. The installed capacity of the plant is 90 kW and the investment costs were approximately EUR 307,000 (USD 372,000), giving a specific cost of approximately EUR 3.4 million (USD 4.12 million) per installed MW.[36]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Besides the premium tariffs discussed above, financial support for renewable energy projects in Croatia includes, at the national level, the environmental protection loan scheme issued by the Croatian Bank for Reconstruction and Development (HBOR) and conducted through commercial banks, as well as financial incentives in the form of interest-free loans or subsidies offered by the Environmental Protection and Energy Efficiency Fund (EPEEF). On the international level, financial support for renewable energy development in Croatia is offered by the European Bank for Reconstruction and Development (EBRD) and the European Regional Development Fund (ERDF).[34]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

In addition to the projected shifts in average annual temperature, climate change is expected to impact the hydrological environment in Croatia in several ways. While recent observations have recorded a marked increase in average annual precipitation across Croatia, other indicative scenarios project a decrease in precipitation over the long term. In particular, the United Nations Development Programme (UNDP) climate projections for Croatia for the period 2070–2100 predict that relative to the base period (1961–1990), winter precipitation will increase by 16.5 mm, while summer precipitation could decrease by as much as 75.6 mm.[5,37] While the overall hydrological impact on a geographically diverse country such as Croatia is difficult to predict, some estimates expect a decrease in runoff in western Croatia of 10–20 per cent by the middle of the 21st century.[34]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are several barriers to the development of SHP in Croatia, including:
- Bureaucratic obstacles in the form of strict EU regulations and the complex structure of state and local agencies within Croatia responsible for issuing permits for development and operation of SHP plants;
- Pressure from the economically important tourism sector in Croatia to preserve the environmental and aesthetic integrity of rivers;
- Lack of funding due to high upfront costs and long payback periods;
- Difficulties SHP producers face in balancing responsibilities.

Enablers of SHP development in Croatia include:
- Proven commitment on the part of the Government to promote renewable energy in general;
- The knowledge base provided by previous studies that have carefully mapped the SHP potential in the country.

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Greece

John K. Kaldellis and Panagiotis Triantafyllou, University of West Attica

KEY FACTS

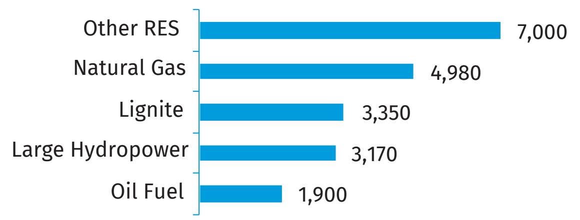
Population	10,715,549 (2020)[1]
Area	131,957 km^2 [2]
Topography	Greece is a peninsular country, with an archipelago (Aegean) containing over 2,500 islands.[3] The coastline of Greece, including the islands, measures almost 15,000 kilometres. Greece is one of the most mountainous countries in Europe, with 80 per cent of its area covered with mountains. The Pindus Mountain Range stretches across the centre of the country from the north-west to the south-east, with a maximum elevation of almost 2,650 metres. Central and western Greece features high and steep peaks intersected by many canyons and other karstic landscapes, including the Meteora and the Vikos Gorges, the latter being one of the largest in the world, plunging vertically for more than 1,100 metres. Mount Olympus is the highest point in Greece, rising to 2,919 metres above sea level.[4,5]
Climate	Greece has a Mediterranean temperate climate, with mild, wet winters and hot, dry summers. The year can be divided into two main seasons: the cold and rainy season, which lasts from mid-October until the end of March, and the warm and dry season, which lasts from April to October. The coldest months are January and February, with average minimum temperatures between 5 °C and 10 °C in coastal areas and between 0 °C and 5 °C in mainland areas. In the northern part of the country, the winter is much cooler, with temperatures occasionally falling down to -20 °C. In the months of July and August, the average maximum temperatures range between 29 °C and 35 °C.[2,4,5]
Climate Change	Climate change is already being felt in Greece, with extreme heat waves during the summer of 2021 causing maximum daily temperatures to reach 46.3 °C and massive wildfires in different parts of the country.[6] Projected changes to mean summer temperatures include increases of 1.5–2.5 °C over the 2021–2050 period, and of as much as 5 °C by 2100, relative to the baseline period 1961–1990. The length of dry spells is also projected to increase by as many as 40 additional consecutive dry days in the central parts of the country by 2071–2100.[2]
Rain Pattern	Rainfall in Greece, even during the winter, does not last for many days and winter storms usually end in mid-February. Average annual precipitation varies from 500 to 1,200 mm in the north-west and from 380 to 800 mm in the south-east.[4,5] The lowest annual precipitation is observed on the Cyclades islands.
Hydrology	The most important rivers in Greece are the Evros, Nestos, Strimon, Axios, Aliakmon, Penios, Arachthos, Acheloos, Sperchios and Alfios. The Acheloos River has a considerable water flow of approximately 300 m^3/s during December, while the flow rate of the Axios is almost 230 m^3/s in March. Finally, the flow rate of the Evros varies between 200 and 220 m^3/s from January to March. The total domestic water resources are estimated at 85 TWh/year, while the annual specific theoretical hydrodynamic potential of Greece amounts to 0.73 GWh/km^2. The technically and economically exploitable hydropower potential is estimated at 21 TWh/year.[4,7]

ELECTRICITY SECTOR OVERVIEW

The national Electricity Generation System (EGS) is divided into two main sectors: the interconnected system of the mainland, referred to as the Hellenic Electricity Transmission System (HETS), and the autonomous power plants of the Aegean Archipelago islands (also known as the Non-Interconnected Islands or NIIs).[8] With the recent completion of the first phases of the Cyclades Interconnection project by the Independent Power Transmission Operator (IPTO) of Greece, the electrical systems of Paros (including Naxos, Antiparos, Ios, Sikinos, Folegandros), Syros and Mykonos islands are now interconnected with HETS. The majority of the remaining Aegean islands (including Crete, the rest of the Cyclades, the Dodecanese and the islands of the north-eastern Aegean) are expected to be interconnected with HETS between 2021 and 2030, starting with the interconnection of Crete, which is expected to be completed by the end of 2023.[9,10]

As of December 2019, the total installed capacity of Greece was approximately 20,400 MW, comprising the installed capacity of HETS (18,200 MW) and the installed capacity of the NIIs, including Crete and Rhodes (2,200 MW). Renewable energy sources (RES), including wind power, solar photovoltaics (PV), large and small hydropower, biomass and cogeneration, provided 10,170 MW (50 per cent) of the total installed capacity, with large hydropower alone providing 3,170 MW (16 per cent) and other RES providing 7,000 MW (34 per cent). Natural gas-fired power plants operated by the Public Power Corporation (PPC) and by private companies provided 4,980 MW (24 per cent); lignite provided 3,350 MW (16 per cent), following the shutdown of the Ptolemais lignite power plant; and oil fuel-fired power plants, operated exclusively on the NIIs, provided 1,900 MW (9 per cent) (Figure 1).[11,12] By August 2021, the installed capacity of RES in Greece reached 7,609.2 MW, including 4,059.9 MW of wind power, 3,196.6 MW of solar power, 247.2 MW of SHP and 105.5 MW of biomass and biogas.[13]

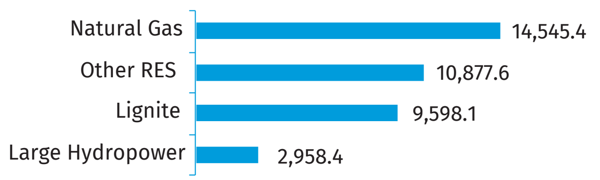
Figure 1. **Installed Electricity Capacity by Source in Greece in 2019 (MW)**



Source: Energypedia,[11] HEDNO[12]

Annual electricity generation in 2019 reached 37,989.4 GWh, excluding the interconnections' energy balance. Natural gas provided 14,545.4 GWh (38 per cent) of this total, RES (excluding large hydropower) 10,887.6 GWh (29 per cent), lignite 9,598.1 GWh (25 per cent) and large hydropower 2,958.4 GWh (8 per cent) (Figure 2).[14]

Figure 2. **Annual Electricity Generation by Source in Greece in 2019 (GWh)**



Source: IPTO[14]

Access to electricity in Greece is 100 per cent.[15] Annual electricity demand in Greece equalled 42,896.9 GWh in 2019.[16] The evolution of electricity demand over the last few decades has been non-linear. The significant increase in Gross Domestic Product (GDP) during 2000–2008 was accompanied by a corresponding increase in electricity consumption, which peaked at 57 TWh in 2008. Subsequently, the economic crisis in Greece led to a significant decline in consumer activity, with electricity demand in 2014 dropping to the level of 2000. Since then, electricity consumption has remained almost constant at 2014 levels. Given the continuing economic uncertainty, the demand for electricity is not expected to recover in the near future. However, due to consumption outpacing domestic generation, imports form a significant share of the electricity supply, reaching 18 per cent of consumption in 2020.[17] Imports from the Balkan counties have increased in recent years, due to the relatively low cost.

In recent years, a series of legislative reforms has been attempted in order to liberalize the state monopoly in the electricity sector, but the undertaken efforts have not led to major changes so far. A more significant development has been the effort to reduce CO_2 emissions in the energy sector and promote generation from RES. In line with the European Union (EU) RES targets, Greece is expected to cover 60 per cent of its gross domestic electricity consumption from RES by 2030. At the end of 2020, the RES-sourced share of consumption did not exceed 35 per cent.[14] Due to this fact and the commitments to the European Commission on reduction of CO_2 emissions, as well as the increasing environmental awareness in Greece as a whole, the current political leadership of the Ministry of the Environment and Energy (MoEE) has increased support for the transition to a more renewable electricity generation mix. This has included implementing energy transition development plans in the areas with lignite-fired power plants (mainly western Macedonia and the Peloponnese regions). Following the Decarbonization Master Plan announced by the Government of Greece, the lignite-fired power plants in Ptolemais and Amyntaio were decommissioned during 2020, while three additional lignite plants in Kardia and Megalopoli were to complete the decommissioning process by the end of 2021, leading to an aggregate removal of 810 MW of installed capacity from the Greek electricity system.[18]

Meanwhile, the RES sector has been experiencing extensive development, including the rapid addition of 2,500 MW from solar PV power plants during 2011–2013 spurred by high feed-in tariffs (FITs) for solar power, the support provided to the construction of large wind farms, particularly on the islands of the Greek Archipelago, in addition to the planned undersea interconnection of the islands with the mainland. Moreover, new investments in the RES sector have been announced, including a 2 GW cluster of solar power parks, which have attracted the interest of many European key players on the market.[11,18]

In 2019, the cost of electricity generation was based on the respective System Marginal Price (SMP) and the price of electricity to consumers was implicitly controlled by the Government. The marginal production cost for the interconnected system varied between 50 EUR/MWh (59 USD/MWh) and 90 EUR/MWh (106 USD/MWh), with an average value of 60 EUR/MWh (70 USD/MWh). Due to the impact of the COVID-19 pandemic on the electricity sector in the country, in the first months of 2020 the average wholesale monthly SMP had decreased by more than 20 EUR/MWh (24 USD/MWh) compared to the analogous period in 2019.[19]

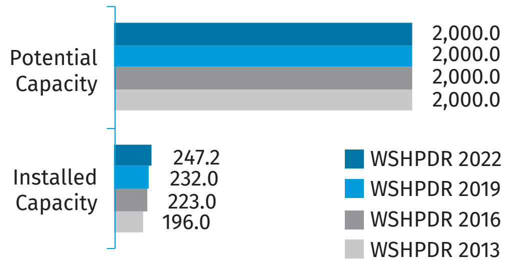
In the case of electricity production from SHP, the electricity price ranges between 85 EUR/MWh and 100 EUR/MWh (100-

118 USD/MWh), adjusted every year through a Ministerial Decree. The average electricity price of SHP in 2020 was 86 EUR/MWh (101 USD/MWh).[20]

SMALL HYDROPOWER SECTOR OVERVIEW

SHP is defined in Greece as hydropower plants of up to 15 MW of installed capacity. The installed capacity of SHP in Greece stood at 247.2 MW as of August 2021, corresponding to slightly over 1 per cent of the current national power mix.[13] Approximately 120 SHP plants operate in Greece under official licences, with installed capacities ranging from 60 kW to 10.8 MW.[21,22,23] The economically feasible SHP potential is estimated at 2,000 MW, indicating that only approximately 12 per cent of this potential has been developed. The overall annual technically feasible hydropower generation potential in Greece is estimated at 20 TWh.[24] Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP in Greece had increased by approximately 7 per cent, while the potential estimated SHP capacity has remained the same (Figure 3).[4]

Figure 3. **Small Hydropower Capacities in the WHSPDR 2013/2016/2019/2022 in Greece (MW)**



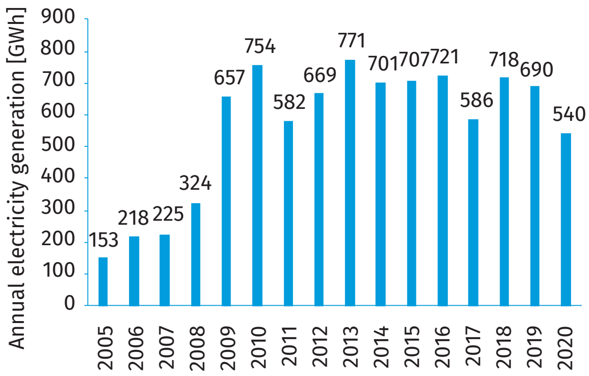
Source: *WSHPDR 2019*,[4] DAPEEP,[13] *WSHPDR 2013*,[25] *WSHPDR 2016*[26]

Note: Data for SHP up to 15 MW.

In 2009, the installed SHP capacity was approximately 182 MW, indicating a gradual increase of approximately 7 MW per year and corresponding to a construction of 5–10 new SHP plants annually. The same year, only 95 MW out of the total installed SHP capacity corresponded to projects with a capacity of more than 5 MW, while 37 MW were composed of mini- and micro-hydropower projects with an installed capacity of less than 1 MW.[21,22,23]

Annual electricity production from SHP increased from 153 GWh in 2005 to 754 GWh in 2010 and has experienced moderate fluctuation in subsequent years. In 2020, generation from SHP decreased to 540 GWh due to the prevalent dry weather conditions. The evolution of annual generation from SHP plants between 2005 and 2020 is displayed in Figure 4.[24] The estimated average load factor of SHP projects varied between 25 per cent in 2020 and 35 per cent in 2019, almost twice the corresponding value of large hydropower plants in the same period.

Figure 4. **Annual Small Hydropower Generation in Greece between 2005 and 2020 (GWh)**



Source: Sakellari et al.[24]

A large portion of the water resources in Greece is concentrated in the western and northern parts of the mainland, along with the majority of existing hydropower plants including SHP plants. Large numbers of SHP plants in Greece are located in Central Macedonia (exploiting the abundance of rivers in the region) and Epirus (owing to its rugged terrain), as well as in Western Greece. As of December 2020, 54.0 MW of SHP were installed in Central Macedonia, 46.9 MW in Epirus, 47.6 MW in Western Greece, 32.9 MW in Sterea (Central Greece), 27.9 MW in Thessaly, 24.8 MW in Western Macedonia, 6.2 MW in the Peloponnese and approximately 4.7 MW in East Macedonia-Thrace, Attica and Crete.[21,22,23]

The national SHP installed capacity target for 2030 is 350 MW. As of 2020, new SHP projects awaiting implementation in Greece totalled 70 MW. The total SHP installed capacity was expected to increase by approximately 10 MW by the end of 2021.[27,28] A partial list of existing SHP plants in Greece is displayed in Table 1, while lists of selected ongoing SHP projects and potential SHP sites are displayed in Tables 2 and 3, respectively.

Table 1. **List of Selected Existing Small Hydropower Plants in Greece**

Location	*Municipality*	*Capacity (MW)*
Ardeutiki Dioryga of River Aliakmonas (Makrochori)	Veroia	10.80
Exodos Siraggas Leontariou	Sofades	10.00
River Louros	Arta	8.70
Exodos Siraggas Mornou	Delfoi	8.50
SHP Paliouri	Zitsa	7.40
SHP Klimatias	Zitsa	7.40
Kleideres of Rema Platanias	Argithea	6.85
Eleoussa	Chalkidona	6.60
Bridge Floka Alfeios	Ancient Olympia	6.59
River Acheloos - Army Region	Agrinio	6.20
River Glafkos - Zoupata Souliou	Patra	5.50

Location	Municipality	Capacity (MW)
Roufrachti - Kerkini	Irakleia	5.00
River Smiksiotikos	Grevena	4.95
River Inachos	Makrakomi	4.50
River Aliakmonas - Abbey of Ilarionas	Kozani	4.20
River Kalamas	Filiata	4.20
Rema Malakassiotiko	Meteora	4.18
Asprorema	Almopia	4.10
Gkoura (Smiksi - Plagia - Agia Triada)	Central Tzoumerka	3.90
River Glafkos - Roufraktis	Patra	3.70

Source: Greek Association of Small Hydropower Plants,[20,27] DAPEEP[28]

Table 2. **List of Selected Ongoing Small Hydropower Projects in Greece**

Location	Municipality	Capacity (MW)
River Louros - Preveza	Arta	8.70
Makrochori II	Apostolos Pavlos	4.84
Smokovo II	Tamasio	3.20
Vermio	Veroia	1.80

Source: Greek Association of Small Hydropower Plants,[27] DAPEEP[28]

Note: Data as of 2021

Table 3. **List of Selected Potential Small Hydropower Sites in Greece**

Location	Municipality	Potential capacity (MW)	Status
Ladonas	Gortynia	10.00	Feasibility study completed
Kalamas	Souli and Filiata	5.80	Feasibility study completed
Ilarionas	N/A	4.00	Feasibility study completed
Chelidonou	Acharnes - Thrakomakedones	1.23	N/A
Psyttaleia	Piraeus	0.35	N/A

Source: Greek Association of Small Hydropower Plants,[27] DAPEEP[28]

Note: Data as of 2021

RENEWABLE ENERGY POLICY

The Government of Greece supports the expansion of RES in the domestic energy balance, in line with the EU policy on decarbonization. However, the targets established as part of this policy have been ambitious and often poorly planned, including the rapid expansion of large-scale wind power and solar power (an additional capacity of 640 MW and 930 MW, respectively, by the end of 2021). Owning to issues stemming from the current poor infrastructure of electricity networks and the negative social reactions to the establishment of large wind farms, some of the aforementioned targets may be jeopardized.[26]

Stemming from the fact that by the end of 2017 the installed capacity of solar power had reached almost 2,650 MW, exceeding the capacity targets previously set for 2020, the Government of Greece decided to limit the uncontrolled dynamics of the domestic RES market by both reducing dramatically the electricity purchase price (which in 2012 was 0.5 EUR/kWh (0.6 USD/kWh)) and impose a retroactive tax of 30 per cent on revenues from solar PV plants for the years 2012 and 2013.[29] In this context, the enthusiasm of the Government for the further development of water resources for hydropower use also decreased, as large hydropower faced persistent negative reactions from local communities and SHP was not considered capable of significantly altering the foundations of the national energy mix.[26]

In 2016, the Parliament of Greece approved a new law (Law 4414/2016) on the RES sector. The new law allows feed-in premium (FIP) schemes, competitive tenders and virtual net metering. While virtual net metering was allowed for any type of RES, access to it was limited to certain institutions such as city and regional councils, educational institutions, farmers and farming associations.[30] The previously active FIT scheme closed on 31 December 2015 and was replaced by the aforementioned law. The Government additionally granted priority to RES with regards to the use of the grid.

Law 4425/2016, regulating the MoEE alongside other Ministries, was amended by Law 4512/2018 with provisions establishing the following four markets: the wholesale market of forward electricity products (renamed the “energy financial market”), the Day-Ahead market, the Intraday market and the Balancing Market. Another key provision of the amended law was the establishment of the Hellenic Energy Exchange (“HEnEx”). Under this framework, the wholesale electricity market model (referred to as the “target model”) was introduced, aiming to gradually harmonize different national electricity markets so that a unified EU electricity market can be realized. The final stage of the integration of RES units into the target model in Greece was expected to begin at the end of 2021. Under the provisions of Law 4512/2018, the IPTO will be responsible for managing the markets and balancing the system in real time, preparing the ground for new energy trading procedures and having a significant impact on the methods used to calculate final electricity costs.[31]

COST OF SMALL HYDROPOWER DEVELOPMENT

Although SHP projects in Greece are not associated with significant environmental problems or negative social reaction as is often the case with large hydropower plants, there is also no significant state support for SHP development.[32] The initial development cost of an SHP plant ranges from 0.8 million EUR/MW to 1.5 million EUR/MW (0.94–1.76 million USD/MW) with the typical price corresponding to 1 million

EUR/MW (1.17 million USD/MW).[33,34] In its turn, the relevant annual operation and maintenance (O&M) cost is estimated at approximately 1–2 per cent of the corresponding turnkey cost for SHP plants with an installed capacity under 10 MW.

During the previous decade, state subsidies for SHP projects accounted for up to 40 per cent of the initial capital for new SHP projects.[33] Nowadays, although there are still state incentives for the implementation of new SHP projects, prices for the purchase of electricity produced from SHP are low. However, SHP projects are still considered a financially efficient investment option, as attested to by the current high investment interest.

EFFECTS OF CLIMATE CHANGE ON SMALL HYDROPOWER DEVELOPMENT

During dry years the generation of electricity from SHP in Greece has fluctuated considerably and has been on a decreasing trend since 2018 despite the growth of total installed SHP capacity. However, the future impact of climate change on Greece is uncertain. Although the length of the dry season is expected to increase over the course of the next century by as many as 40 additional days, the volume of surface runoff is also projected to increase by 16–30 per cent.[2] Greater instability in the water supply to hydropower plants can thus be expected. Additionally, hydropower development is already facing significant negative attention from local communities and environmental groups and is likely to fall under increased scrutiny if access to water resources becomes less secure, especially in cases of competing priorities in water resources allocation such as the Acheloos water transfer project.[2]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Some of the major factors decelerating expansion of SHP in the electricity market of Greece include the following:

- Lengthy administrative procedures for obtaining the licensing required for SHP construction, usually taking up to three years;
- The absence of an integrated national water management plan, which allows stakeholders competing for water resources with hydropower to use informal means and political influence to secure their access to these resources at the expense of SHP;
- Lack of interest in investment in SHP from large developers due to low profit margin; development is thus driven primarily by small companies which face challenges including limited budgets, expertise and knowledge of the SHP sector.

The main enabling factor for SHP development in Greece is the substantial undeveloped SHP potential, especially in certain regions of the country. Policy developments that could support the realization of this potential include the adoption of a careful and fair national water management plan that would balance the interests of all stakeholders in the water use sector, as well as integrated strategic plans for the development of SHP cascades on a single water course, which would allow for economies of scale to increase the economic efficiency of the construction of each individual site and attract the interest of large investors and developers.

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Italy

Emanuele Quaranta and Ioannis Kougias, European Commission Joint Research Centre

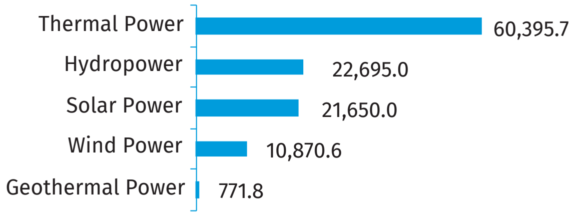
KEY FACTS

Population	60,244,639 (2019)[1]
Area	302,068 km^2[2]
Topography	The territory of Italy is mostly mountainous. The Alps form the northern boundary of the country and the Apennine Mountains stretch north to south along the length of the Italian Peninsula. The largest plain is the Po Valley (71,000 km^2) and the highest peak is Mont Blanc (4,810 metres above sea level).[3]
Climate	Northern Italy experiences cold winters and hot and humid summers. Winters in central Italy are milder, while very hot summers and very mild winters predominate in the south and on the islands. Average temperatures are from 3 °C (north) to 14 °C (south) in January and from 28 °C (north) to 30 °C (south) in July.[3]
Climate Change	An increase in temperature of up to 2 °C over the period 2021–2050, relative to the period 1981–2010, is expected due to climate change. In the worst-case scenario, the temperature increase may reach 5 °C. Summer precipitation will decrease in the central and southern regions, whereas intense precipitation events are projected to increase. Across all scenarios, the number of hot days and periods without rain will increase.[4]
Rain Pattern	Mean annual rainfall in Italy is approximately 1,000 mm. The highest values occur in the north-east (>2,500 mm). On the islands and in the south, the rainfall rarely exceeds 500 mm per year.[3]
Hydrology	There are approximately 1,200 rivers in Italy, but they are generally shorter than in other European countries due to the relatively small distance between the mountains and the sea. All rivers have catchments entirely within the country. The longest river is the Po (652 km). Other water sources are glaciers in the Alps.[3]

ELECTRICITY SECTOR OVERVIEW

Total net installed electricity capacity in Italy amounted to 116,383.1 MW as of 2020, with thermal power accounting for 60,395.7 MW (52 per cent of the total), hydropower for 22,695.0 MW (20 per cent), solar power for 21,650.0 MW (19 per cent), wind power for 10,870.6 MW (9 per cent) and geothermal power for 771.8 MW (1 per cent) (Figure 1).[5]

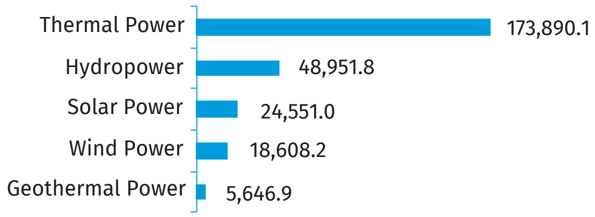
Figure 1. **Installed Electricity Capacity by Source in Italy in 2020 (MW)**



Source: Terna[5]

Net electricity generation in 2020 equalled 271,648.0 GWh, including 173,890.1 GWh (64 per cent of the total) from thermal power, 48,951.8 GWh (18 per cent) from hydropower, 24,551.0 GWh (9 per cent) from solar power, 18,608.2 GWh (7 per cent) from wind power and 5,646.9 GWh (2 per cent) from geothermal power (Figure 2).[6] Small hydropower (SHP) (0–10 MW) accounted for approximately 26 per cent of gross hydropower generation in 2020. Over the last decade, hydropower generation has fluctuated considerably, from a high of 58,545.4 GWh in 2014 to a low of 36,198.7 in 2017.[7]

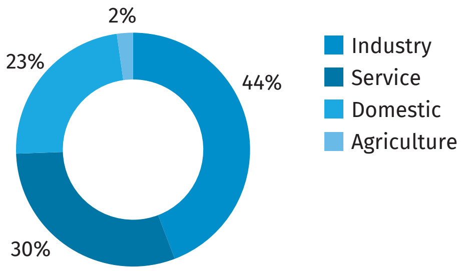
Figure 2. **Annual Electricity Generation by Source in Italy in 2020 (GWh)**



Source: Terna[6]

Minimum and maximum grid load observed in 2020 reached 17,896 MW and 55,166 MW, respectively.[8] The maximum annual grid load in recent years has moved from the winter period to summer, due to the increasing use of air conditioning in the summer. Electricity consumption in 2020 amounted to 283,814.5 GWh, exceeding generation. Imports of electricity the same year totalled 39,789.9 GWh. Domestic consumption was dominated by the industrial sector at 125,417.3 GWh (44 per cent of the total), followed by the service sector at 85,875.0 GWh (30 per cent), the domestic sector at 66,211.6 GWh (23 per cent) and the agriculture sector at 6,310.5 GWh (2 per cent) (Figure 3).[6] Access to electricity in Italy is 100 per cent.[9] However, the existing transmission and distribution networks suffer from congestion at several points. With transmission and distribution losses in 2020 amounting to approximately 3 per cent of gross generation, investments are needed to improve the aging energy infrastructure in order to increase the efficiency and resilience of the networks and to secure power supply for users.[6]

Figure 3. **Share of Electricity Consumption by Sector in Italy in 2020 (%)**



Source: Terna[6]

As a result of liberalization of the energy market, the production, transmission and distribution of electricity In Italy are managed by different companies. These sectors are regulated by the Authority of Electricity and Gas (AEEG, Law 481/1995) and competition is encouraged. Terna S.p.A. is the Transmission System Operator (TSO) and owns 99.7 per cent of the National High-Voltage Transmission Grid, which spans 72,844 kilometres. Since 2014, 11 other companies have been involved in low-voltage grid management at the regional scale. The number of companies generating electricity stood at 16,109 in 2020, an increase of over 3 per cent relative to the 15,579 generation companies operating in 2019. Finally, 12 large companies are active in the distribution subsector. In particular, E-distribuzione S.p.A. accounted for both the largest share of electricity provided to domestic and industrial users (85 per cent) and the share of users provided with electricity (85 per cent).[10]

The regulated wholesale electricity market in Italy was introduced in 2004. The electricity market, commonly called the Italian Power Exchange (IPEX), enables producers, consumers and wholesale customers to enter into hourly electricity purchase and sale of contracts. The market, regulated by the Energy Market Manager (GME), mainly consists of the Day-Ahead Market (MGP) where electricity for the following day is traded, the intraday auction market (MI) based on seven sessions and a platform for ancillary services (MSD) in collaboration with the TSO. In 2019, retail electricity prices in Italy for domestic users were on average 233 EUR/MWh (270.6 USD/MWh) and 96 EUR/MWh (111.5 USD/MWh) for industrial users.[11,12]

The long-term plans of Italy for the development of the energy sector are focused on the reduction of reliance on fossil fuels for electricity production and improving the security of the energy supply, which in the case of Italy is highly sensitive to the global political instability (for example, the Libyan civil war resulted in a 32 per cent reduction of oil imports by Italy from Libya). Consequently, the diversification of energy sources and the promotion of renewable energy sources (RES) are key national objectives.

SMALL HYDROPOWER SECTOR OVERVIEW

Italy is one of the three major producers of hydropower in Southern Europe. The development of hydropower in Italy in the 20th century was dominated by the construction of conventional plants that rely on large dams (reservoir-type hydropower), which induce changes in the landscape and significant alteration of river flow. However, conventional reservoir-type hydropower plants are close to saturation in the country. The remaining unexploited hydropower potential is thus mainly represented by SHP and by the modernization of the existing plants, including reservoir-type plants, in order to satisfy the targets of the Integrated National Energy and Climate Plan.[13] The SHP sector has become increasingly important during the last decade thanks to government policies that have fostered the installation of new SHP plants and have resulted in an expansion of SHP development exceeding expectations.

SHP plants in Italy are classified according to their minimum and maximum capacity:

- Micro-hydropower: P < 0.1 MW;
- Mini-hydropower: 0.1 MW ≤ P < 1 MW;
- SHP: 1 MW ≤ P < 10 MW.

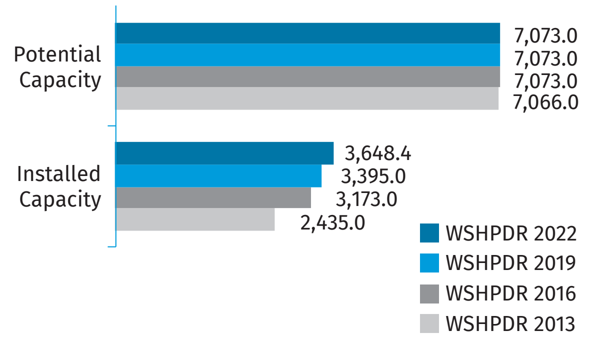
The gross hydropower generation potential in Italy, calculated on the basis of hydrological and topographical factors, is estimated at approximately 200 TWh/year, of which 38 TWh/year is accounted for by SHP. Net hydropower potential, based on technical and economic feasibility of hydropower development as well as the potential of existing plants, is estimated at approximately 50 TWh/year, which is also the annual hydropower generation target set by the National Energy Strategy of Italy (2017) for 2030. This goal will be realized primarily by supporting the renovation of large hydropower plants (some of which were built 100 years ago) as well as the construction of SHP plants.[14] Estimates of the technical SHP generation potential range between 12.5 TWh and 20 TWh, while potential SHP capacity, including currently operational plants, is estimated at 7,073 MW.[3,15]

As of 2020, there were 3,271 micro- and mini-hydropower (up to 1 MW) plants in operation in Italy with a cumulative installed capacity of 902.1 MW, in addition to 922 SHP (1–10 MW) plants with a cumulative installed capacity of 2,746.3 MW. The total installed capacity of all SHP plants up to 10 MW in 2020 was thus 3,648.4 MW, indicating an increase of approximately 2 per cent over the previous year's total of

3,575.1 MW.[5] SHP plants (up to 10 MW) produced a total of 12,195 GWh in 2020.[7]

Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP in Italy has increased by over 7 per cent, owing to the rapid development of SHP in the country in recent years. Thus, since 2018, 576 new micro-, mini- and small hydropower plants were constructed, representing a nearly 16 per cent increase. The estimate of potential capacity of SHP in Italy has remained unchanged due to lack of current and accurate survey data (Figure 4).[3] A list of 20 recently constructed SHP plants is displayed in Table 1.

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Italy (MW)**



Source: Terna,[5] *WSHPDR 2019*,[3] *WSHPDR* 2016,[15] WSHPDR *2013*[16]

Table 1. **List of Selected Existing Small Hydropower Plants in Italy**

Plant Name	*Location*	*Capacity (MW)*	*Head*	*Plant type*	*Operator*	*Launch year*
Badia	Mella River	0.280	3.6	N/A	INIZIATIVE MELLA S.R.L.	2021
OP Monte Argento	Nera River	0.100	7.0	N/A	ERG HYDRO S.P.A.	2021
Bassana	Mella River	0.280	2.1	N/A	INIZIATIVE MELLA S.R.L.	2020
Calcagna	Mella River	0.170	1.4	N/A	INIZIATIVE MELLA S.R.L.	2020
Urago DMV	Oglio River	0.330	3.2	N/A	IN.BRE. S.P.A.	2020
Palosco DMV	Oglio River	0.290	5.7	N/A	IN.BRE. S.P.A.	2020
Exilles	Galambra Creek	2.490	508.0	N/A	SIMI S.R.L.	2019
Turano DMV	Turano River	0.100	49.6	N/A	ERG HYDRO S.P.A.	2019
Santa Maria Magale	Nera River	0.300	4.3	N/A	ERG HYDRO S.P.A.	2019
Moncalieri	Piemonte	4.500	N/A	Run-of-river	IREN ENERGIA S.P.A.	2015
Casnigo	Lombardia	5.265	N/A	Run-of-river	ENERCOS SPA	2012
Marebbe - Enneberg	Trentino Alto Adige	0.736	N/A	Run-of-river	OFF.ELETT. S.VIGILIO DI MAREBBE SPA	2012
Valdagno	Veneto	0.160	N/A	Run-of-river	IMPIANTI AGNO SRL	2011
Recoaro Terme	Veneto	0.132	N/A	Run-of-river	IMPIANTI AGNO SRL	2011
Posina	Veneto	0.070	N/A	Run-of-river	IMPIANTI ASTICO S.R.L.	2011
Valle Aurina - Ahrntal	Trentino Alto Adige	7.968	N/A	Run-of-river	AURINO ENERGIA SRL	2011
Vignola	Emilia Romagna	1.050	N/A	Run-of-river	CENTRO-ELETTRICA SPA	2011
Brennero - Brenner	Trentino Alto Adige	0.400	N/A	Run-of-river	COOPERATIVA CENTRALE ELETTRICA FLERES SOC. COOP. A R.L.	2011
Bellano	Lombardia	4.580	N/A	Run-of-river	HYDRO ENERGY POWER S.R.L.	2011
Monno	Lombardia	3.520	N/A	Run-of-river	AZIENDA ELETTRICA OGLIOLO SRL	2011

Source: Frosio Next[18]

Gestore dei servizi energetici S.p.A (GSE) is the organization responsible for regulating the RES sector in Italy. Among other functions, it issues authorizations for construction of new plants based on RES, including SHP plants. In 2019, 239 SHP plants were authorized, for a total installed capacity of 103.6 MW, an average capacity of 430 kW per plant (Table 2).[19]

Table 2. **Small Hydropower Plant Authorization Procedures in Italy in 2019**

GSE procedure	*Total installed capacity (MW)*	*Number of plants*	*Average plant capacity (MW)*
1	21.5	5	4.30
2	10.0	77	0.13
3	3.1	6	0.52
4	2.5	1	2.50
5	14.7	3	4.90
6	10.0	91	0.11
7	1.6	3	0.53
8	23.1	5	4.62
9	16.2	46	0.35
10	0.9	2	0.45
Total	**103.6**	**239**	

Source: GSE[19]

One of the ongoing trends in SHP development in Italy is the installation of hydropower plants on water distribution networks, especially in aqueducts. In 2020, 24 SHP plants to be installed on aqueducts were authorized for construction, with a total installed capacity of 3.26 MW.[20] A list of several plants authorized for construction on aqueducts in 2020 is provided in Table 3.

Table 3. **List of Selected Ongoing Small Hydropower Projects in Italy**

Location	*Capacity (kW)*	*Plant type*	*Developer*	*Authorization year*
Magasa	42.36	Aqueduct	Comune di Magasa	2020
Berzo Demo	49.95	Aqueduct	Comune di berzo Demo	2020
Erice	54.00	Aqueduct	Siciliacque spa	2020
La Thuile	64.70	Aqueduct	Comune di La Thuile	2020
Salbeltrand	79.00	Aqueduct	Comune di Civio Lombardia	2020

Source: GSE[20]

Note: As of 2020.

SHP growth in Italy has been driven by comprehensive feed-in tariffs (FITs) introduced in 2008, set at 0.22 EUR/kWh (0.26 USD/kWh) for 15 years, with subsequent modifications.[21] For hydropower plants up to 1 MW, the FIT is an alternative to Green Certificates (GC), while hydropower plants above 1 MW receive both the incentive and the GC.[14,22] The GC, which conventionally certifies the production of 1 MWh of renewable energy, is issued by the GSE at the request of the owner of a plant powered by an RES and is a negotiable share with a value of 1 MWh. These incentives have been effective at promoting the construction of new SHP plants. However, the Government of Italy, which has borne the financial cost of these incentives, has recently started a gradual reduction of FITs for SHP.

The current FITs are set by the Renewable Energy Source (FER) Decree of 2019. While the FIT rates under the new decree are significantly lower compared to the previous rates (a reduction of between 15 per cent and 65 per cent depending on the installed capacity), the duration of the contract is longer by 5–15 years, providing additional security to potential investments. The FIT rates for SHP under the new decree are provided in Table 4.[21]

Although it is still an important source of electricity, substantial additional development of hydropower in Italy is not expected in the coming years. The Government's plan for large hydropower mainly involves the refurbishment of existing plants. Construction of new large plants is constrained by the absence of suitable sites and by the extensive environmental impact expected from such projects, which is difficult to mitigate in a densely-populated country such as Italy. Likewise, SHP development is also not expected to expand despite the significant unexploited potential, with wind and solar power likely to take the lead in RES development in the coming years.

Table 4. **Feed-in Tariffs for Small Hydropower Plants in Italy in 2019**

Category	*Feed-in tariff in EUR/MWh (USD/MWh)*	*Duration (years)*
Run-of-river plants:		
1 < P ≤ 400 kW	115 (118)	20
400 < P ≤ 1,000 kW	110 (133)	25
P > 1,000 kW	80 (97)	30
Reservoir plants:		
1 < P ≤ 1,000 kW	90 (109)	25
P > 1,000 kW	80 (97)	30

Source: GSE[21]

At the same time, Italy has been and remains a global center of research on hydropower, with a particular focus on SHP. Due to the wide-spread diffusion of old mills, research on water wheels has been very active at the Polytechnic University of Turin, and water wheels have proven to be effective and fish-compatible hydropower converters for very low-head sites, typically below 30 kW[23,24]. For high-head sites, the research conducted at the University of Padua is worth mentioning on Pelton turbines, while studies on Cross Flow turbines have taken place at the University of Palermo.[25,26] The hydrological aspects of hydropower operation, eco-hydraulic studies on fish passages and plant sustainability are also under investigation at various institutions.[27,28,29] Efficient and innovative technologies are also being developed by private companies, especially for SHP plants on low-head sites and aqueducts. Examples include the VLH turbine and the Mariucci turbine.[30]

Several research projects ongoing as of 2021 include the RIBES project on river flow regulation and fish behaviour in hydropower contexts and the RELAID project on dams. The University of Perugia is cooperating with industry on sediment dilution studies, while the University of Salerno is testing rainwater-powered pico-Pelton turbines to be used for domestic purposes (Rain Eco Power).[31] Finally, the University of Naples is working on the REDAWN project focused on turbines in water distribution networks.[32]

The expansion of the RES sector as a whole, in line with the European Union (EU) and international targets, may prove beneficial to system integration (between electricity, hydropower and gas systems in particular), which should be implemented on a trial basis, including with a view to researching the most efficient long-term storage methods for renewable energy. The National Energy and Climate Plan (NECP) of Italy estimates that the number of permanent staff in the field of hydropower development is likely to grow from 15,294 in 2017 to 16,380 in 2030.[13]

RENEWABLE ENERGY POLICY

In 2019, Italy submitted a 10-year Integrated NECP under the terms of EU Regulation 2018/1999 on the Governance of the Energy Union and Climate Action. Based on its NECP, Italy intends to accelerate the transition from traditional fuels to RES by promoting the gradual phasing out of coal for electricity generation in favour of an energy mix based on a growing share of RES and, for the remainder, gas-fired thermal power.[13] Making this transition a concrete reality requires the planning and construction of replacement plants and the necessary infrastructure.

Italy is committed to the reductions of greenhouse gas emissions, agreed to at the EU and the international level. For those sectors covered by the EU Emissions Trading System (EU ETS)—primarily the thermoelectric sector and energy-intensive industries—measures adopted in pursuit of emissions reduction include the phasing out of coal by the end of 2025, contingent upon replacement plants and necessary infrastructure being constructed on schedule, a high CO_2 allowance price and a significant acceleration of RES deployment and energy efficiency measures in manufacturing processes.[13] The CO_2 allowance price on the EU ETS reached 65 EUR/ton (75.5 USD/tonne) in October 2021, more than doubling its value since October 2020.[33] The high carbon price provides a competitive advantage to hydropower and other RES in Italy as these technologies are associated with reduced greenhouse gas emissions and are thus exempt from carbon taxation.

Moreover, RES will play an important role in reaching the goal of reducing CO_2 emissions by 40–70 per cent by 2050 compared to the 2010 emissions levels. This target was established at the G7 summit in June 2015 and is expected to lead to the decarbonization of the economy of Italy over the course of the following decades. The target share of energy from RES in the gross final consumption of energy in Italy by 2030 is 30 per cent for the economy as a whole and 22 per cent for the transport sector, with the goal of entirely eliminating fossil fuels in electricity production by 2050.[13]

The FER Decree of 2019 divides power plants that can access incentives into four groups based on the plant type, RES type and category of intervention:

- Group A includes the new construction, full reconstruction, reactivation or enhancement of on-shore wind farms as well as newly-built solar photovoltaic (PV) systems;
- Group A-2 includes newly built solar PV systems whose modules are installed to replace roofs of buildings and rural structures;
- Group B includes new (greenfield) hydropower plants, those undergoing complete reconstruction (excluding plants on aqueducts) and the reactivation or upgrading of plants utilizing gas residues from purification processes;
- Group C includes plants subject to total or partial refurbishment: on-shore wind farms, hydropower plants and plants utilizing gas residues from purification processes.[21]

There are two different ways of accessing the incentives depending on the power of the plant and the group to which it belongs:

- Registration on a priority list: plants with an installed capacity greater than 1 kW (20 kW for solar PV) and less than 1 MW belonging to Groups A, A-2, B and C must be registered on a priority list;
- Participation in auctions: plants with an installed capacity greater than or equal to 1 MW belonging to Groups A, B and C must participate in auctions, through which the quota of available power is assigned in accordance with incentive levels.

An annual capacity threshold for incentives for hydropower of 80 MW has been introduced.[21]

There are two different incentive mechanisms, depending on the power of the plant:

- The All-inclusive Tariff (TO) consisting of a single tariff, corresponding to the tariff due, which also remunerates the electricity collected by the GSE;
- An Incentive (I), calculated as the difference between the tariff due and the hourly energy price, since the energy produced remains available to the operator.

For power plants up to 250 kW, it is possible to choose one of the two modes, with the possibility of switching from one mode to the other no more than twice during the entire incentive period. Plants with a power capacity greater than 250 kW, on the other hand, can only access the Incentive (I) mechanism.[21]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP plants with a capacity larger than 100 kW are required to undergo a Strategic Environmental Assessment (SEA).[34] The Decree on Fisheries of 1931 sets the main regulatory framework for aquafauna in Italy, but is rarely applied. In line with this law, additional protections regulating the impact of hydropower on aquafauna are set by provincial governments rather than the national Government.[35] For example, the Piedmont Province, where many SHP plants are located, has comprehensive regulations requiring all weirs and barrages to be equipped with fish passes.[36]

COST OF SMALL HYDROPOWER DEVELOPMENT

The cost of construction for SHP plants in Italy typically range from 3,000 EUR/kW to 11,700 EUR/kW (3,463.5– 13,507.5 USD/kW). Cost for small projects (up to 1,000 kW) is typically much higher per kW than for larger projects with an installed capacity of several MW or above, particularly with regard to personnel costs.[37] Construction costs can be reduced by retrofitting and repowering existing structures.[30]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

According to models of future climate change, the hydropower potential in Italy is projected to decrease due to lower precipitation and water availability. Studies predict reductions in generation potential of 22 per cent by 2070 relative to the beginning of the 21st century, as well as a 30 per cent reduction in summer runoff in the Italian Alps between 2016 and 2065 and a consequent reduction of generation by run-of-river plants of approximately 3 per cent over the same time horizon.[38,39] Nevertheless, this decreasing trend is expected to be compensated for by additional generation realized through the refurbishment of existing plants. While Italy is expected to remain a key regional player in providing ancillary services, this role will be mainly fulfilled through reliance on its extensive pumped hydropower capacity.[40]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main barriers to SHP development in Italy include the following:

- The recent adoption of the new FER Decree of 2019 has significantly decreased FITs for SHP compared to 2016. Payback periods have consequently been extended, which is likely to discourage investors.
- The authorization process in Italy takes 2–3 years on average. Permits (water concessions, construction licenses, etc.) are granted by different departments. Moreover, there is no substantial difference between the water concession for SHP and for large hydropower plants. Finally, the recent introduction of a threshold on the annual installed capacity (and consequently the ranking procedure for competitive plants) has further slowed down the authorization process.
- Social mobilization against SHP is increasing in Italy, especially in the northern part of the country (the Alps). Even though the impact of SHP on aquatic ecosystems and local communities is smaller compared to large dams, it is not insignificant when the ratio of generated power to impact is taken into account, as well as the cumulative impact of SHP cascades located along a single watercourse There are examples of new SHP plants that have been stopped or whose construction was delayed because of this opposition.

Enabling factors for SHP development in Italy include:

- A well-developed incentive system, albeit with reduced benefits;
- Untapped small hydropower potential, e.g. at existing barriers, old mills and in aqueducts;
- Extensive local industrial and scientific capacity for innovative SHP projects;
- Despite the recent negative perception of SHP among some parts of the population, many examples of sustainable SHP projects exist in Italy, such as the rehabilitation of historic mills, and the installation of SHP plants on existing structures such as previously non-powered dams, water distribution networks and navigation locks, that significantly reduce any additional impacts. There are likewise examples of SHP projects that have generated benefits and income flows for local communities, such as those in the Valle Maira (Piedmont) region.[30]

Given the recent expansion of SHP plants in Italy and the disturbance on riverine ecosystems, an emphasis must be placed on combining the energy/financial needs of various stakeholders with environmental preservation. The SHP technology is likely to gain a higher social value in the next decades if the environmental and hydrological footprint associated with the hydropower exploitation of surface water takes a higher priority in civil infrastructure planning. Furthermore, the hidden potential in existing infrastructures and facilities should be considered.[41]

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Montenegro

Goran Sekulić, University of Montenegro

KEY FACTS

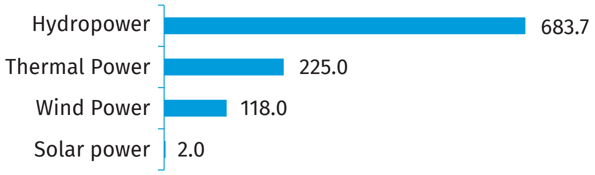
Population	622,028 (2019)[1]
Area	13,810 km^2[2]
Topography	The northern part of Montenegro is dominated by high mountains, descending through the central part with large depressions, ending in a coastal plain varying in width from several hundreds of metres to several kilometres from the coast. The lowest part of the central inland area are the valleys of the Zeta River, comprising the Zeta-Bjelopavlići Plain. The Tara River Gorge is the lowest canyon in Europe, with a depth of 1,300 metres. The mountain ranges in the north include 37 peaks with heights above 2,000 metres. One of the highest peaks is the Bobotov Kuk, reaching 2,523 metres.[2]
Climate	The southern region of Montenegro has a Mediterranean climate, with hot and dry summers and relatively rainy winters. The central and northern regions have the characteristics of a mountainous climate, although the influence of the Mediterranean Sea is also evident. The highest average temperature is in July with 18.9 °C and the lowest is in January with –1.5 °C.[3]
Climate Change	Climate projections indicate that by 2040, the annual temperature will increase by 1.5-2 °C throughout the country. By 2070, the average annual temperature will rise by up to 3 °C, while the projected increase by 2100 is 5.5 °C. The annual average rainfall is expected to decrease, especially during the summer months, coupled with an increase in precipitation in the winter months in some parts of the country. It is expected that by 2070 the average annual rainfall will be reduced by 20 per cent over the entire territory.[3]
Rain Pattern	Annual precipitation across the country is very irregular, ranging from approximately 800 mm in the far north to approximately 5,000 mm in the far south. The mean annual precipitation in the country is 1,138 mm. Rainfall is the highest in November, with an average of 123 mm. It is the lowest in August, with an average of 66.3 mm.[4]
Hydrology	The main rivers within the Adriatic Sea basin are the Morača, Zeta, Cijevna and Bojana; and within the Danube River basin they are: the Piva, Tara, Lim, Ibar and Ćehotina. The largest onshore surface water body is Lake Skadar, which is shared between Montenegro and Albania.[4]

ELECTRICITY SECTOR OVERVIEW

The main energy resources used in Montenegro for producing electricity are hydropower and thermal power from coal, with some wind power capacity as well. According to the latest report from the Energy Regulatory Agency, in Montenegro there was 1,028.7 MW of installed capacity in 2019. Of the total, hydropower plants accounted for 683.7 MW of installed capacity, thermal power for 225.0 MW, wind power for 118.0 MW and solar power for 2 MW (Figure 1).[5,6,7] Since 2013, installed capacity increased by 96.0 MW. The hydropower capacity comes from two large plants, Piva (342 MW) and Perucica (307 MW), as well as 23 small hydropower (SHP) plants (34.7 MW).

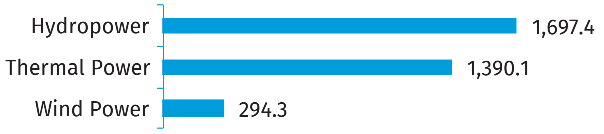
In 2018, the production of electricity amounted to 3,743.90 GWh, which is in the highest level reached within the previous 10-year period. Compared to the average generation achieved over the past decade, electricity generation in 2018 increased by almost 21 per cent. This resulted in a 15 per cent higher generation than planned, with hydropower exceeding the planned generation by almost 22 per cent. In 2018, renewbale generation made up 61 per cent of the toal, including 57 per cent (2,138.14 GWh) from hydropower.[5] In 2019, electricity generation reached 3,381.8 GWh, of which 59 per cent was from renewable energy sources (Figure 2).

Figure 1. **Installed Electricity Capacity by Source in Montenegro in 2019 (MW)**



Source: Energy Regulatory Agency,[5,7] Balkan Green Energy News[6]

Figure 2. **Annual Electricity Generation by Source in Montenegro in 2019 (GWh)**



Source: Energy Regulatory Agency[7]

Montenegro has a 100 per cent electrification rate. As a candidate country for the European Union (EU) accession and a contracting party of the Energy Community Treaty, it has an obligation to follow EU policy for energy and environment. The Energy Law (2016) is fully in line with the Third Energy Package, as well as its bylaws.[8]

The main electricity generator in Montenegro is Elektroprivreda Crne Gore (EPCG). In July 2017, a former strategic partner with the Government, Italian company A2A, initiated a withdrawal procedure by exercising the put option after its contract expired on 1 July 2017. The Government decided to purchase A2A shares, increasing its ownership stake to 88.6 per cent in total. In 2009, Crnogorski elektroprenosni sistem (CGES) was established, becoming the independent transmission system operator, and in 2016 the Crnogorski elektrodistributivni sistem (CEDIS) was established, becoming the independent distribution system operator. This has unbundled the transmission and distribution responsibilities from EPCG.

The electricity network of Montenegro consists of transmission and distribution capacities, which include: high (HV), medium (MV) and low voltage (LV) power lines, as well as transformer stations. The transmission system consists of 110 kV facilities, 110/x kV substations, 110 kV lines, as well as facilities, substations and lines of voltage level higher than 110 kV. A 375 km-long High Voltage Direct Current (HVDC) undersea electricity cable was put into operation at the end of December of 2019 (Trans-Balkan Corridor Project).[9] It connects Italy and Montenegro through converter stations on both coasts and 400 kV overhead lines in Montenegro. Furthermore, interconnection lines to Serbia and Bosnia and Herzegovina are under construction. The realization of the HVDC undersea electricity cable project enabled a 400 kV line ring to be formed, which will contribute to the safety and stability of the transmission system and relieve the 110 kV voltage level system. The structure and geographic disposition enable good connections with the neighbouring systems of Serbia (two 220 kV lines and one 110 kV line), Bosnia and Herzegovina (one 400 kV line, two 220 kV lines and two 110 kV lines), Albania (one 400 kV line and one 220 kV line) and Kosovo (one 400 kV line).[7]

Due to the complexity and large area occupied by the distribution system, the Montenegro territory is divided into seven regions. The distribution system consists of 35 kV facilities, 35/x kV substations and 35 kV lines, as well as facilities, substations and lines of lower voltage levels. According to the data available for 2019, the total length of the distribution network was 19,561.4 km. The distribution system is in its final phase of replacement of the old electricity meters with smart meters, which can provide a real-time data exchange with the data centre. Additionally, the reconstruction of a LV network is ongoing. As a result, the electricity losses from the distribution network (complete losses, technical and so-called commercial losses) are steadily decreasing, from 15.6 per cent in 2016 to 13.2 per cent in 2019.[7]

The electricity market of Montenegro was opened based on the decisions of the Energy Regulatory Agency (RAE) and the Energy Law of 2003. Since 2017, the electricity prices for small customers and households are determined by the Energy Law of 2016 (Table 1). All other customers must either buy electricity from the market or choose a supplier. The retail price for distributed consumer categories is calculated based on the active electricity, the engagement of the transmission and distribution capacities, the transmission and distribution network losses, as well as fixed fees for the electricity system operators. RAE is responsible for setting the allowed revenue for the system operators and prices related to the network charges.

In 2019, the average realized price of electricity, which includes the fee for encouraging renewable energy sources for customers connected to the distribution system, was 0.091 EUR/kWh (0.11 USD/kWh) (excluding VAT). On 1 June 2019, the Government passed a decree on a fee for stimulating the production of electricity from renewable sources and highly efficient cogeneration, which abolished the fee for encouraging renewable energy sources for customers whose consumption is less than 300 kWh.[7]

Table 1. **Regulated Electricity Tariffs in Montenegro as Defined by Energy Law of 2016**

Consumption category	*Price (EUR/kWh (USD/kWh))*
35 kV	0.05 (0.06)
10 kV	0.07 (0.09)
Distribution customers at 0.4 kV whose power is measured	0.10 (0.12)
Distribution customers at 0.4 kV whose power is not measured, two-tariff measurements	0.08 (0.10)
Distribution customers at 0.4 kV whose power is not measured, one-tariff measurements	0.10 (0.12)

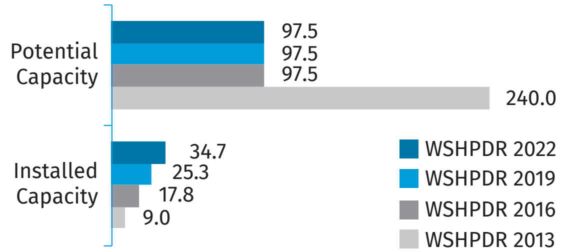
Source: Electricity Regulatory Agency[10]

SMALL HYDROPOWER SECTOR OVERVIEW

In Montenegro, SHP is defined as hydropower plants with installed capacity of less than 10 MW. At the end of 2019 there were 23 SHP plants in operation, from which 7 are 30 or more years old and 16 were built in the last 10 years. As a result, in 2019, the overall installed SHP capacity was 34.74 MW with annual generation of 80.34 GWh.[7] Compared to the

World Small Hydropower Development Report (WSHPDR) 2019, the installed capacity increased by approximately 37 per cent, with the change being due to recently concluded 36 concession contracts for 55 new SHP sites (Figure 3). A total of EUR 13 million was put aside for these contracts in 2018, with a further EUR 30 million allocated for 2019.[15] The potential capacity figure compared to the *WSHPDR 2016* and *WSHPDR 2019* has remained unchanged.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Montenegro (MW)**



Source: Energy Regulatory Agency,[7] *WSHPDR 2013*,[11] *WSHPDR 2016*,[12] *WSHPDR 2019*[13]

The development of the power system in Montenegro in the 20th century, in addition to the construction of large power plants, was marked by the construction of SHP plants. Since 2013, after a break of almost 24 years, a new stage of intensive SHP construction has begun with the introduction of incentive measures for the use of renewable energy sources (Table 2). From then until the end of 2019, 16 SHP plants were put into operation, which increased the total projected utilization of the hydropower potential of smaller watercourses to approximately 0.108 TWh.[14] Fifty-five further SHP projects are under development (Table 3).[15]

Table 2. **List of Selected Operational Small Hydropower Plants in Montenegro**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Turbine type*	*Operator*	*Launch year*
Bistrica Majstrovina	Bijelo Polje	3.06	695.5	Run-of-river	2x Francis	DOO Hydro Bistrica Podgorica	2018
Šeremet Potok	Andrijevica	0. 79	105	Run-of-river	1x Pelton	DOO Nord Energy Andrijevica	2018
Piševska rujeka	Andrijevica	1.08	360	Run-of-river	1x Pelton	DOO Igma Energy Andrijevica	2017
Babino polje	Plav	2.21	1743.5	Run-of-river	1x Pelton	DOO Kronor Podgorica	2017
Šekular	Berane	1.68	1198.5	Run-of-river	1x Pelton	DOO Hidroenergija Montenegro Podgorica	2016
Jara	Plav	4.56	2232.7	Run-of-river	2x Pelton	DOO Kronor Podgorica	2016
Bistrica	Berane	5.60	164	Run-of-river	2x Pelton	DOO Hidroenergija Montenegro Podgorica	2015
Rmuš	Berane	0.47	194	Run-of-river	1x Pelton	DOO Hidroenergija Montenegro Podgorica	2015
Spaljevići 1	Berane	0.65	105	Run-of-river	1x Pelton	DOO Hidroenergija Montenegro Podgorica	2015
Orah	Berane	0.95	110	Run-of-river	1x Pelton	DOO Hidroenergija Montenegro Podgorica	2015
Jelovica 2	Berane	0.62	45	Run-of-river	1x Pelton	DOO Hidroenergija Montenegro Podgorica	2015
Vrelo	Bijelo Polje	0.62	943.7	Run-of-river	1x Pelton	DOO Synergy Podgorica	2015
Bradavec	Andrijevica	0.95	250	Run-of-river	3x Pelton	DOO Igma Energy Andrijevica	2015
Jezeršti-ca	Berane	0.84	360	Run-of-river	1x Pelton	DOO Hidroenergija Montenegro Podgorica	2014
Lijeva rijeka	Podgorica	0.11	410.8	Run-of-river	Banki	EPCG AD Nikšić	1955
Šavnik	Šavnik	0.20	26	Run-of-river	Francis	EPCG AD Nikšić	1955
Glava Zete	Danilovgrad	4.48	221.5	Run-of-river	Kaplan	DOO Zeta Energy Danilovgrad	1955
Slap Zete	Danilovgrad	1.71	7	Run-of-river	Kaplan	DOO Zeta Energy Danilovgrad	1952
Rijeka Mušovića	Kolašin	1.95	160	Run-of-river	Pelton	EPCG AD Nikšić	1950
Rijeka Crnojevića	Rijeka Crnojevića	0.65	25	Run-of-river	1x Michell–Ossberger	EPCG AD Nikšić	1948
Podgor	Cetinje	0.48	54	Run-of-river	Michell–Ossberger	EPCG AD Nikšić	1940

Source: Sekulić[15]

Table 3. **List of Selected Ongoing Small Hydropower Projects in Montenegro**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Turbine type*	*Developer*	*Planned launch year*	*Stage of development*
Vrbnica	Plunica	6.50	251	Run-of-river	1x Pelton	MHE Vrbnica DOO	2021	70%
Jelovica 1	Berane	3.15	180	Run-of-river	1x Pelton	Hidroenergija Montenegro DOO	2020	90%
Mojanska 1	Andrijevica	1.78	113	Run-of-river	1x Pelton	Small Hydro Power Plant Kutska DOO	2020	90%
Kutska 1	Andrijevica	1.66	81.5	Run-of-river	1x Cross-flow	Small Hydro Power Plant Kutska DOO	2020	90%
Mojanska 2	Andrijevica	1.10	110	Run-of-river	1x Pelton	Small Hydro Power Plant Kutska DOO	2020	90%

Source: Sekulić[15]

As detailed in the Energy Development Strategy until 2030, EPCG is planning to undertake reconstruction of existing SHP plants with a combined capacity of 11.4 MW. The Strategy includes data from the 2001 Water Master Plan, which estimates the overall theoretical hydropower potential of Montenegro to be between 10.6 TWh and 10.8 TWh and the technical potential between 5.0 TWh and 5.7 TWh.[12] However, upon taking data from the previous on-site hydrometric measurements at locations on small rivers into account, it appears that these data are an underestimation. By 2014, three series of one-year measurements were finished at approximately 40 locations on 35 rivers.[16] The programme continues and today hydrometric measurements are ongoing. The state of the hydrometric measurement network is continuously improving in terms of the number of automatic stations and the quality of the equipment. Therefore, it is expected that the estimated hydropower potential on individual water streams will become more reliable.[16]

Under the National Renewable Energy Action Plan (NREAP) objectives, it was intended that by 2020, the installed capacity of SHP plants would amount to a total of 97.5 MW, with an annual generation of 287 GWh (Table 4). This would require a 280 per cent increase compared to the current installed SHP capacity. With the newly approved reconstruction projects expected to increase the installed SHP capacity to 94.8 MW, the country is close to achieving this objective.[17] Given the lack of accurate data on the total SHP potential of the country, the current chapter uses the 97.5 MW target as the minimum estimate of available SHP potential.

Table 4. **National Goals for the Construction of Small Hydropower up to 2020 in Montenegro**

Plant size	*Capacity (MW)*	*Generation (GWh)*
< 1 MW	11.2	35
1–10 MW	86.3	252
Total	**97.5**	**287**

Source: Ministry of Economy[12]

RENEWABLE ENERGY POLICY

The existing generation portfolio relies on hydropower and coal, however, the Strategy for Energy Development in Montenegro up to 2030 foresees intensive usage of wind power, solar power and biomass as well as other renewable energy sources as a priority. Hydropower is planned to remain the dominant source, with wind power contributing significantly as well. Moreover, the NREAP up to 2020 was adopted in 2014, taking into account the Energy Community Ministerial Council Decision D2012/04/MC-EnC, which obliged Montenegro to adopt the Renewable Energy Directive 2009/28/EC and establish a national target of 33 per cent of the total energy consumption and 51.4 per cent of the total electricity consumption from renewable energy sources by 2020.[12] The NREAP also defines the targets for different types of renewable energy. Installed capacity from the hydropower plants was planned to total 826 MW by 2020, with an annual generation of 2,050 GWh.[13]

In Montenegro, electricity from renewable sources is supported through a feed-in tariff (FIT). The operators of plants that generate electricity from renewable sources can obtain the status of a privileged producer and thereupon acquire the right to a price support for the generated electricity under the legal requirements. Every year in January, a new incentive fee is adopted, which is applied to the end customers, who bore the costs from renewable energy sources. The amount of the incentive fee to encourage the production of electricity from renewable energy sources and cogeneration in 2018 was 0.0047 EUR/kWh (0.0057 USD/kWh). The Energy Market Operator (COTEE), who is legally obliged to buy electricity from privileged producers, pays the incentive for a period of 12 years after having concluded a formal agreement. The exact amount is determined in the Tariff System Decree and mainly depends on the type of renewable energy technology.[12]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

In order to improve and accelerate the authorization process for the renewable energy sources, a new and simple procedure for authorizing the construction of SHP plants with an installed capacity of up to 1 MW was established. The FITs for SHP are based on the annual electricity generation and favour the construction of smaller facilities (Table 5). The same flat rate FIT is also implemented for the refurbished SHP plants.[14]

Table 5. **Feed-in Tariffs for Small Hydropower Plants in Montenegro**

Power at plant's exit (P_{PE})	*Incentive price (EUR/kWh (USD/kWh))*
P_{PE} < 1MW	0.10 (0.13)
1 ≤ P_{PE} < 3 MW	0.10 (0.13)–(0.7 * P_{PE})
3 ≤ P_{PE} < 5 MW	0.09 (0.11)–(0.24 * P_{PE})
5 ≤ P_{PE} < 8 MW	0.08 (0.10)–(0.18 * P_{PE})
8 ≤ P_{PE} < 10 MW	0.07 (0.08)

Source: Ministry of Economy[18]

Note: The first column represents the installed capacity reduced by losses from the turbine, generator and transformation. The second column shows the incentive price calculated based on the power at the plant's exit.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change will modify the seasonality of inflows and the annual volumes of water exploitable for hydropower generation in Montenegro, which will affect the management and revenue of hydropower plants. A decrease in the water balance in all river basins in Montenegro has been observed, and further reduction of rainfall and snowfall will drastically affect the availability of surface waters. By the end of the 21st century, the average annual flow is expected to decrease by 27 per cent. Adaptation measures should focus on the application of an integrated approach to water resources and systems management and on strengthening cross-sectoral planning and activity.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Despite the measures and actions undertaken by the Government to improve the legislative and developmental processes for SHP, many obstacles for developing an attractive environment for investment still remain.

Grassroots activists in Montenegro have campaigned against hydropower, which has led to the Government entering into negotiations on the termination of contracts for the construction of seven SHP plants in four northern municipalities.[19] Furthermore, corruption allegations have been brought forward against the Prime Minister, President as of the moment of writing of this chapter, who signed a concession for the construction of an SHP plant to the company owned by his son.[20]

The following points summarize the main barriers to SHP development that have been identified:

- Public opposition against hydropower, including SHP, due to environmental consequences;
- Government negotiations to terminate SHP contracts in response to public opposition;
- Recent corruption allegations regarding SHP concession contracts;
- No accurate data available on potential water flow and site capacity;
- Complex procedure for obtaining opinions and permits from numerous relevant state institutions;
- Complicated procedure of connecting to the electricity distribution network, as well as an increase in costs in the cases when the connection point is located very far from the power plant.[10,20]

The following points summarize the main enablers for SHP development in Montenegro that have been identified:

- The need for increased security of electricity supply;
- Rise of a competitive energy market in the country;
- Potential for job creation in the less developed parts of the country through SHP projects;
- The need to increase energy efficiency.

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North Macedonia

Sotir Panovski and Gordana Janevska, University St. Kliment Ohridski

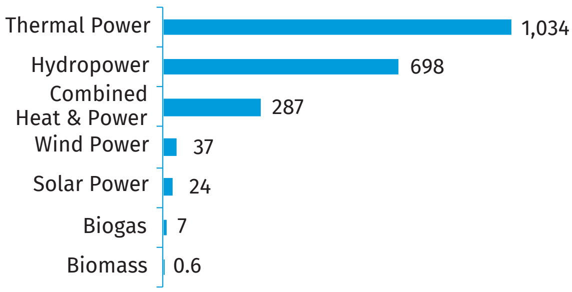
KEY FACTS

Population	2,976,255 (2019)[1]
Area	25,713 km^2 [2]
Topography	North Macedonia is a landlocked country, located in the Balkan Peninsula in South-Eastern Europe. It has a mountainous territory covered with deep basins and valleys. The country is bisected by the Vardar River; there are also three large lakes, each divided by a frontier line. The highest point is Mount Korab at 2,753 metres above sea level and the lowest point lies at 50 metres above sea level at the Vardar River.[2]
Climate	The climate of North Macedonia is transitional from Mediterranean to continental. It is characterized by warm and dry summers and autumns (June–October), with July and August being the warmest months with temperatures exceeding 40 °C in some regions. Winters (December–February) are relatively cold with heavy snowfall. The coldest month is January with an average temperature of 0.3 °C. Average annual temperatures range from less than 0 °C in January to 20 °C in July and August.[3]
Climate Change	North Macedonia, as a signatory to the United Nations Framework Convention on Climate Change, has agreed to provide information on its nationally defined contributions to the objectives of the Paris Agreement.[4] The new methodology will integrate climate change into the new spatial plan.[5] It is projected that the average temperature in North Macedonia will increase by 1.0 °C in 2025, 1.9 °C in 2050, 2.9 °C in 2075 and 3.8 °C in 2100, while precipitation is expected to decrease by 3 per cent in 2025, 5 per cent in 2050, 8 per cent in 2075 and 13 per cent in 2100 in comparison with the 1961-1990 period.[6]
Rain pattern	Average annual precipitation varies between 1,700 mm in the western mountainous region and 500 mm in the eastern part of the country. The wettest months are November, December, April and May.[3]
Hydrology	In North Macedonia, there are four river basins (the Vardar, Crn Drim, Strumica and South Morava) and three natural lakes (Ohrid, Prespa and Dojran). There are 21 large reservoirs and 120 smaller reservoirs and artificial lakes. The water level in these surface waterbodies mainly depends on precipitation and snowmelt.[5] The National Hydrometeorological Service performs hydrometric measurements and observations of surface waters using 110 hydrological stations.[7]

ELECTRICITY SECTOR OVERVIEW

Electricity production in North Macedonia mainly originates from lignite and large hydropower. In 2019, the total installed capacity stood at 2,088 MW, including almost 50 per cent from thermal power, over 33 per cent from hydropower, almost 14 per cent from combined heat and power plants, less than 2 per cent from wind power, 1 per cent from solar photovoltaics (PV) and less than 0.5 per cent from biogas and biomass combined (Figure 1). Compared to 2018, the total installed capacity increased by 10.9 MW.[8]

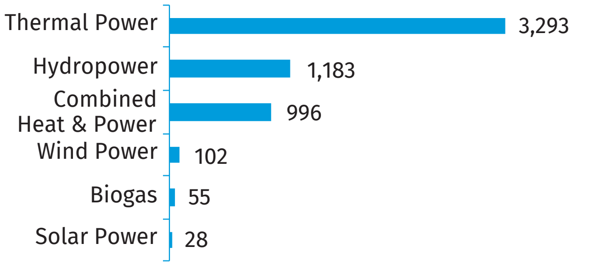
Figure 1. **Installed Electricity Capacity by Source in North Macedonia in 2019 (MW)**



Source: ERC[8]

Electricity generation in 2019 totalled 5,658 GWh. Thermal power plants contributed over 58 per cent, hydropower 21 per cent (including 263 GWh from small-scale plants), combined heat and power plants almost 18 per cent, wind power less than 2 per cent, biogas 1 per cent and solar PV 0.5 per cent (Figure 2).[8] North Macedonia is also dependent on imports for its electricity supply. In 2019, 24 per cent of electricity supply (1,826 GWh) was imported from four neighbouring countries: Serbia, Bulgaria, Greece and Albania. In 2019, 20 traders/suppliers imported electricity in North Macedonia. The Hungarian Electricity Market (HUPX) is considered a reference market for comparing the movements of the wholesale electricity market in North Macedonia. In 2019, the average import price was 54.7 EUR/MWh (64.3 USD/MWh).[8]

Figure 2. **Electricity Generation by Source in North Macedonia in 2019 (GWh)**



Source: ERC[8]

The most important renewable resource in North Macedonia is hydropower, with large hydropower accounting for 28 per cent of total installed capacity and small hydropower (SHP) for 5 per cent. The share of wind power in the country's energy mix will increase in the future, adding to the current capacity of 36.8 MW from Bogdanci, the first wind park in the country. Electricity generation from solar power plants is also increasing. Finally, several biogas plants are also in operation with a total installed capacity of 6.99 MW.[8]

Construction of the following hydropower projects is planned: Galiste (78 MW) by 2035, Globocica II (20 MW) by 2035, Veles (96 MW) by 2030, Gradec (75 MW) by 2030, Cebren (458 MW) by 2029, Vardar Valley SHP 1 plants (45 MW) by 2025, Vardar Valley SHP 2 plants (152 MW) by 2030 and other SHP projects (135–160 MW) by 2021. By 2040, additional capacities of 86 MW of wind power, 13 MW of biomass thermal power and 92.5 MW of SHP (including those under construction or with the status of a temporary preferential producer) will be built under the feed-in tariff system (FIT).[9]

The electrification rate in North Macedonia is close to 100 per cent with some remote areas still lacking access to the grid. The distribution grid is operated by EVN Macedonia, which, according to the Energy Law, is responsible for grid development and upgrading.

As a candidate country for the European Union (EU) membership and a contracting party in the Energy Community, North Macedonia is committed to applying the EU Community Acquis in domestic legislation. Thus, the Energy Law adopted in 2018 transposed the EU Third Energy Package in the electricity and natural gas sector, as well as the Renewable Energy Directive.[10]

In 2019, the electricity market of North Macedonia was fully liberalized. On the electricity market, in accordance with the Energy Law, two new entities appeared, namely the EVN HOME DOO Skopje responsible for providing electricity supply as a universal service, and the MEMO DOOEL Skopje entrusted with the organization and management of the electricity market.[10] Electricity transmission is performed by the state-owned Electricity Transmission System Operator (MEPSO). The electricity transmission system connects the larger production capacities and the country's two electricity distribution systems. The power transmission network operates at the 400 kV and 110 kV voltage levels. Electricity distribution is performed by two separate legal entities, with the distribution network covering the following voltage levels: 110 kV, 35 kV, 20 kV, 10 kV, 6 kV and 0.4 kV.[8]

The support for renewable energy sources will continue to develop in line with the Directive 2009/28/EC, which is transposed with the adoption of the Energy Law and by-laws. The Energy Law contains requirements for a competitive bidding process for FITs, which will enable support for renewable energy producers and market integration of renewable energy sources.[9] The strategy foresees further development of the distribution system network to integrate more renewable energy sources, as well as continuous improvement of the network reliability.

The electricity market reform implemented in 2019 enabled all consumers to freely choose an electricity supplier at prices and tariffs approved by the Energy Regulatory Commission.[8] Average electricity rates are shown in Table 1.

Table 1. **Average Electricity Selling Prices in North Macedonia**

Tariff type	*Average selling price (USD/kWh)*		
	2018	*2019*	*2021*
Consumers – 35 kV	0.044	0.043	0.093
Consumers – 10(20) kV	0.051	0.050	0.093
Other I level	0.059	0.057	0.075
Other II level	0.170	0.170	0.182
Households 1T	0.087	0.087	0.059
Households 2T	0.080	0.080	0.117

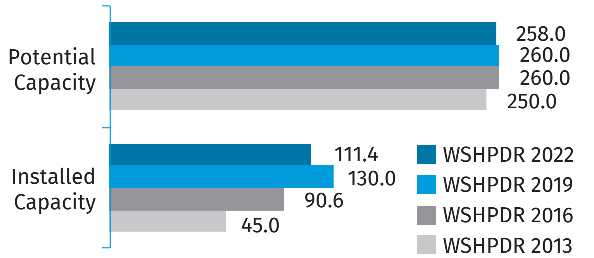
Source: ERC[8,11]

SMALL HYDROPOWER SECTOR OVERVIEW

North Macedonia defines SHP as hydropower plants with an installed capacity of 10 MW or less.

In 2019, the installed capacity of SHP in North Macedonia was 111.43 MW (5.34 per cent of the total installed capacity) from a total of 101 plants generating 263 GWh.[8] Out of the total number of SHP plants, 90 sell the produced electricity at the FIT, while the remaining 11 plants sell the produced electricity on the electricity market. SHP currently accounts for 16 per cent of the total installed hydropower capacity.[8] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity decreased by 14 per cent, whereas the potential decreased only slightly, both changes being based on more accurate data (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in North Macedonia (MW)**



Source: ERC,[8] Republic Committee for Energy,[12] *WSHPDR 2013*,[13] *WSHPDR 2016*,[14] *WSHPDR 2019*[15]

In 2007, a concession for the construction of SHP plants in North Macedonia began, with approximately 120 SHP projects signed until 2021. The concessions for the use of water for electricity generation are based on the DBOT model (Design–Build–Operate–Transfer). In accordance with tender documentation, water concessions are granted for a period of 23 years beginning on the day of signing of a concession agreement. The concessionaire has the right to apply for an extension of the concession period. The projects include the Vardar Valley SHP 1 project consisting of multiple SHP plants with a combined expected capacity of 45.0 MW (start year 2025), the Vardar Valley SHP 2 project with a combined expected capacity of 152.5 MW (start year 2030) as well as other SHP projects started in 2019 for a total SHP capacity (including existing plants) of a maximum of 135–160 MW (Table 2). Additionally, the capacity of the water supply systems could be used for SHP development if justified based on economic and technical aspects.[9]

Table 2. **Most Recently Commissioned Small Hydropower Plants in North Macedonia**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Turbine type*	*Operator*	*Launch year*
Topolka 315	Caska	2.160	214	Pelton	MHE Topolki Dooel Skopje	2020
Topolka	Caska	2.880	226	Pelton	MHE Topolki Dooel Skopje	2020
Kovacka 23	Makedonski Brod	0.990	123	Francis	Actuel energy group DOO Skopje	2020
Kovacka 22	Makedonski Brod	0.504	98	Francis	Actuel energy group DOO Skopje	2020
Kovacka 21	Makedonski Brod	0.504	100	Francis	Actuel energy group DOO Skopje	2020
Topolka 317	Caska	1.997	126	Francis	MHE Topolki Dooel Skopje	2019
Filternica	Bitola	0.408	52	Francis	JP Strezevo Bitola	2019
Dovledjik	Bitola	0.472	63	Francis	JP Strezevo Bitola	2019
MHEC Odrenska reka 106	Tetovo	0.360	166	Pelton	Super nuova energy DOO Tetovo	2019
MHEC Odrenska reka 105	Tetovo	0.360	135	Pelton	Super nuova energy DOO Tetovo	2019
MHE Lukar 3	Kavadarci	0.250	95	Francis	MHEC Lukar DOOEL Kavadarci	2019
MHE Lukar 2	Kavadarci	0.250	94	Francis	MHEC Lukar DOOEL Kavadarci	2019
MHE Lukar 1	Kavadarci	0.250	95	Francis	MHEC Lukar DOOEL Kavadarci	2019
MHE Gabrovska reka	Tetovo	1.800	390	Pelton	Nord energy group DOO	2019
MHE Padiska 14	Gostivar	0.480	103	Francis	MHE Padiska DOO Skopje	2019
Konska 184	Gevgelija	0.990	113	Francis	Actuel energy group DOO Skopje	2018
MHE Recica i Grmesnica	Ohrid	0.720	123	Francis	Energomont-MZT-DOO Bitola	2018
MHE Vranovska reka 312	Caska	0.792	144	Francis	MHE Topolski DOO Skopje	2018
MHE 267 Semnica`	Bitola	0.800	152	Francis	Energomont-MZT-DOO Bitola	2017
MHE so r.b. 115 na Banjanska r	Cucer - Sandevo	0.293	95	Francis	Hidroenergija s. Batinci Studenicani	2017

Source: Republic Committee for Energy,[12] ERC[16]

The Government of North Macedonia has supported the construction of SHP plants as a renewable energy source through FITs (Table 3).[17]

Table 3. **Feed-in Tariffs for Small Hydropower in North Macedonia**

Monthly quantity of distributed electricity (kWh)	*FIT (EUR/kWh (USD/kWh))*
≤ 85,000	0.120 (0.14)
> 85,000 and ≤ 170,000	0.080 (0.09)
> 170,000 and ≤ 350,000	0.060 (0.07)
> 350,000 and ≤ 700,000	0.050 (0.06)
> 700,000	0.045 (0.05)

Source: Ministry of Economy[17]

SMALL HYDROPOWER PROJECTS AVAILABLE FOR INVESTMENT

A study of SHP potential in North Macedonia was conducted in 1982. Its findings suggest the possibility to construct 406 SHP plants with a total installed capacity of 258 MW, with individual capacities ranging from 50 kW to 5 MW and an average annual electricity generation of 1,094 GWh. This study, in fact, serves as a technical base for granting concessions for SHP construction in North Macedonia.[12] Of the listed sites, approximately 100 are under concession. Table 4 shows a sample of five SHP sites from this study.

Table 4. **List of Selected Small Hydropower Sites Available for Development**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site*
Bela reka	Crna reka	2.340	200	New
Satoka	Crna reka	0.645	115	New
Gradeshka	Crna reka	0.522	93	New
Gradeshka	Crna reka	1.000	144	New
Buturica	Crna reka	1.135	208	New

Source: Republic Committee for Energy[12]

RENEWABLE ENERGY POLICY

Increase of the share of renewable sources in the country's energy mix and improvement of energy efficiency are two of the key strategic goals set by the Government for the energy sector.[8,9,10] The support for renewable energy will continue to develop in line with the Directive 2009/28/EC, which was transposed with the adoption of the Energy Law.[10] The share of renewable sources in total electricity production in 2019 was projected to reach 23.9 per cent, however, the actual share for that year stood at 24.2 per cent.[8]

North Macedonia ratified the Paris Agreement and is also converting its legislative and regulatory framework according to the EU 2030 Climate and Energy Framework. The Intended Nationally Determined Contribution (INDC) of North Macedonia includes reduction of CO_2 emissions from fossil fuel combustion by 30 per cent (or by 36 per cent at a higher level of ambition) by 2030 compared to the business-as-usual scenario. The Law on Environment incorporates articles that stipulate general obligations and responsibilities regarding greenhouse gas inventories and the national plan for climate change action.

Renewable energy is covered in the Energy Law and relevant by-laws, including the Decree on measures to support the production of electrical energy from renewable energy sources, the Rulebook on renewable energy sources and the Rulebook for preferential producers that use a FIT.[10,17,18,19] The Strategy for Energy Development of the Republic of North Macedonia until 2040 envisages two types of financial mechanisms to support renewable energy: FITs and feed-in premiums.[9] According to the Decree on measures to support the production of electrical energy from renewable energy sources, all feed-in premiums are to be granted via a tendering procedure. The highest level of support should be achieved in the period 2020–2025 in all three scenarios. The maximum total renewable energy capacity to receive support is set at 570 MW, including the capacity that existed in 2017. The largest supported capacity is for solar PV at 200 MW, followed by SHP at 160 MW and wind power at 150 MW.[17]

FITs for wind power are 0.089 EUR/kWh (0.10 USD/kWh), for biomass thermal 0.150 EUR/kWh (0.18 USD/kWh) and for biogas 0.180 EUR/kWh (0.21 USD/kWh). A premium is awarded to preferential producers for 20 years in the case of wind power plants and for 15 years in the case of solar PV plants.[17]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The development of SHP in North Macedonia is regulated by the Energy Law and relevant by-laws, as well as the Law on Waters, the Law on Concessions and Public Private Partnership and the Law on Construction.[9,17,18,19,20,21,22] In 2020, the Ministry of Economy published the Handbook on the procedures for the development and construction of power plants for electricity production from renewable energy sources — hydropower plants, which aims to provide detailed guidance to investors.[23]

COST OF SMALL HYDROPOWER DEVELOPMENT

Based on the experience of the authors of this chapter and according to a simple calculation of profitability of investment into SHP projects (as a ratio between invested funds and money received from generated electricity), the average payback period in North Macedonia can be estimated at approximately 5–7 years.

In 2019, 90 SHP preferential producers who used the FITs, with a total installed capacity of 80 MW and generation of

170 GWh, were paid EUR 9,063,665 (USD 10,986,793). The average price for produced electricity was approximately EUR 0.813 (USD 0.99) per kWh.[8]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

The Government of North Macedonia has signed several direct agreements with the European Bank for Reconstruction and Development (EBRD) to support loan agreements with several concessionaires. This possibility is available to all investors who signed the agreements and are seeking loans from different financial institutions.[10,15]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The production of electricity from hydropower mostly depends on the hydrological conditions. In 2019, the production from SHP significantly reduced due to the unfavourable hydrological conditions: from 202 GWh in 2018 to 169 GWh in 2019. At the moment, the Government or the Ministry of Economy do not take special measures to address the impact of climate change on SHP.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are no significant barriers precluding SHP development in North Macedonia, but rather some factors that can pose certain limitations:

- There is a need for more accurate hydrological data for an extended time period, because the previous estimates of the capacity potential have been criticized for overestimating the volume of water at some sites;
- There is also a need for connection to the distribution grid, since most of the potential SHP sites are located in rural areas with either no connection or no stable quality network;
- The grid connection cost is often very high, with the average price for the 10 (20) kV cable line at 25,000–30,000 EUR/km (29,400–35,300 USD/km) and for the 35 kV cable line at 30,000–35,000 EUR/km (35,300–41,200 USD/km). The price refers to the total value including design and construction, with the lower level of the price range referring to lighter terrain, plains and fields and the higher level to mountainous terrains with hard surface and partly rocky terrain;
- Since 2020, the construction of new SHP plants should be carefully assessed to avoid the risk of disproportionate environmental impact compared to electricity generated;
- The equipment (turbines, generators, hydromechanical equipment, transformers, glass fibre-reinforced plastic (GRP) pipes, control system) need to be procured from abroad.

The factors that can be considered as enablers for SHP development include:

- There is a significant SHP potential, including the capacity of the water supply systems and coastal SHP, which could be used for plant development if justified based on economic and technical aspects. According to the analysis and opinion of the authors, there are real opportunities for building approximately 110 SHP plants of different types;
- There is a favourable political, social and energy climate for the development of SHP in North Macedonia;
- Availability of bank loans for financing SHP projects as well as FITs;
- Availability of engineering staff as well as construction and maintenance companies experienced in SHP projects.

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Portugal

Laura Stamm, International Center on Small Hydropower (ICSHP)

KEY FACTS

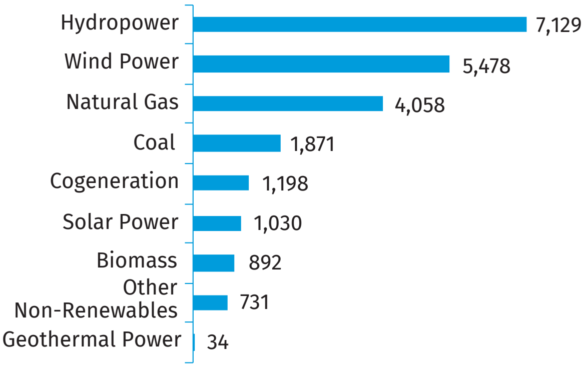
Population	10,297,081 (2020)[1]
Area	92,225.6 km^2 [2]
Topography	The northern and central regions of Portugal have higher elevations with several mountain ranges, whereas the southern region is lower and flatter. In the very north of the country are the Larouco Mountains to the east and the Trás-os-Montes to the west. The Montemuro Mountains, also in the northern region, form south of the Douro River basin and north of the Mondego River basin. In the northern central region is the prominent Estrela Mountain range where the highest altitudes are found and the highest point of the mainland, Serra de Estrela at 1,993 metres, is located. The southern region is largely low-lying plains with marshy coastlines. The Azores Islands in the Atlantic Ocean are of volcanic origin and are the location of the country's highest point, Mount Pico, at 2,351 metres.[2,3]
Climate	The climate has Atlantic, Mediterranean and continental influences. The north, especially north-west has a mild and wet climate with cool winters, warm summers and a lot of rainfall. The interior experiences colder winters and hotter summers, with the exception of very high altitudes that do not reach very high temperatures. The Estrela Mountain region experiences temperatures below 0 °C in winter and snow remains on the peaks throughout most of the year. The southern region has a mild temperate climate with an average range of 10 °C in winter and 24 °C in summer.[2]
Climate Change	The major concerns of climate change in Portugal are rising temperatures and declining annual precipitation. Since the 1970s average temperatures have been increasing at a rate of approximately 0.3 °C per decade and rainfall has been decreasing at a rate of approximately 25 mm per decade. These trends are expected to continue into the next decades and accelerate towards the end of this century. By 2100, temperatures may increase by between 2 °C and 4 °C and rainfall may decrease by an estimated 30 per cent.[3]
Rain Pattern	Precipitation varies between regions and seasons. The north receives the most rainfall, with an average range of 1,000 mm to 2,000 mm per year with some areas receiving more than 2,500 mm per year. Central and southern regions receive an average of 600 mm per year, with some drier pockets inland. Most of the precipitation happens during the winter between November and February, whereas June to August are the driest months.[2,3]
Hydrology	The largest rivers in Portugal begin in Spain and flow through the country to empty into the Atlantic Ocean. These rivers are the Douro in the northern region, The Tagus in the central region and the Guadiana in the south. The largest river exclusively within the country's boundaries is the Mondego which rises in the Estrela Mountains and flows west to the Atlantic. Other important rivers within the country are the Vouga, Sado and Zêzere. Many rivers in the central and southern regions have seasonal variation of flow with extremely low flows during the dry summer season.[2]

ELECTRICITY SECTOR OVERVIEW

In 2020, the total installed capacity in Portugal was 22,421 MW, of which 65 per cent was with renewable sources and 45 per cent with non-renewable sources. Hydropower accounted for 7,129 MW (approximately 32 per cent) of the total installed capacity, wind power for 5,478 MW (24 per cent), natural gas for 4,058 MW (18 per cent), coal for 1,871 MW (8 per cent), cogeneration for 1,198 MW (5 per cent), solar power for 1,030 MW (5 per cent), biomass for 892 MW (4 per cent), other non-renewable sources for 731 MW (3 per cent) and geothermal power for 34 MW (less than 1 per cent) (Figure 1).[4]

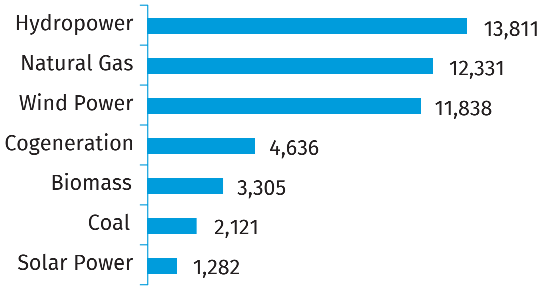
The total electricity generated in continental Portugal in 2020 was 49,324 GWh, of which 62 per cent was from renewable sources and 38 per cent from non-renewable sources. Hydropower generated 13,811 GWh (28 per cent), natural gas 12,331 (25 per cent), wind power 11,838 GWh (24 per cent), co-generation 4,636 GWh (9 per cent), biomass 3,305 GWh (7 per cent), coal 2,121 GWh (4 per cent) and solar power 1,282 GWh (3 per cent). In the same year, 6,397 GWh of electricity was imported and 4,942 GWh of electricity was exported. Total electricity consumed for the year was 50,779 GWh.[5]

Figure 1. **Installed Electricity Capacity by Source in Portugal in 2020 (MW)**



Source: DGEG[4]

Figure 2. **Annual Electricity Generation by Source in Portugal in 2020 (GWh)**



Source: APREN[5]

The electricity sector of Portugal is liberalized, a process that began at the end of the 20th century and was completed around 2014. The market began to open gradually in 1995 and by 2006 all consumers were able to choose their electricity suppliers.[6] Before complete privatization in 2013, Energias de Portugal (EDP) was the main utility company in the country but is now one of many companies, while still holding a considerable market share, especially in regards to distribution.[7] While any company is allowed to generate or distribute electricity, only one company has exclusive rights for all transmission in the country, the Rede Eléctrica Nacional (REN). Since the end of the privatization process of REN that occurred between 2007 and 2014, the State Grid of China has been its largest shareholder with a 25 per cent share.[8]

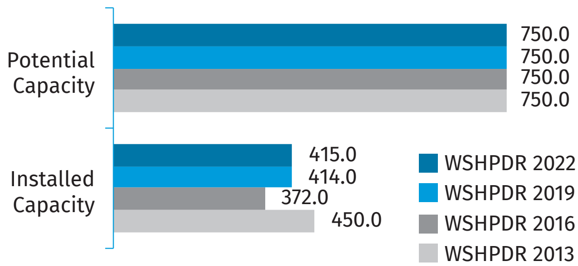
The Iberian Electricity Market (MIBEL) includes both Spain and Portugal. Spot market trading is managed by the Iberian Market Operator of Spain (OMIE) and future market trading is managed by the Iberian Market Operator of Portugal (OMIP).[9] The energy market of Portugal is regulated by the Energy Services Regulatory Authority (ERSE), the sectorial regulator for gas and electricity and an independent legal entity of public law, financially and administratively autonomous according to Decree-Law No. 97/2002 and updated with Decree-Law No. 84/2013.[10] The General Directorate of Energy and Geology (DGEG) oversees the energy sector as a whole and plays an integral role in the implementation of energy legislation and policies.

The electrification rate of Portugal is 100 per cent.[11] There are two types of markets that determine electricity tariffs and consumers are able to choose which market they would like to pay on. The free market is unregulated and prices are determined by the electricity suppliers and are part of the customer's contract. The regulated market is based upon supply and demand, fluctuating hourly. Both types share the same network access tariff base approved by ERSE plus a supplement according to the type. There is a social tariff determined by ERSE available for low-income consumers with contracts under 6.9 kW, which is the same discount regardless of the market the costumer pays on.[6] While free market prices depend on individual companies, the average hourly price on the regulated market in January 2022 was EUR 0.202 (USD 0.21) per kWh.[12]

SMALL HYDROPOWER SECTOR OVERVIEW

In Portugal, small hydropower (SHP) is defined as plants with a capacity of 10 MW or less. At the end of 2021, installed SHP capacity was 415 MW, which generated 845 GWh of electricity for the year.[13] Although there are no accurate or complete studies for SHP potential, the country's National Renewable Energy Action Plan (PNAER) 2013–2020 was aiming for a total of 750 MW capacity from 250 plants by 2020, suggesting that, at a minimum, this potential exists.[10] Current capacity constitutes approximately 50 per cent of this target. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity has increased by 1 MW and potential capacity has remained the same (Figure 3).

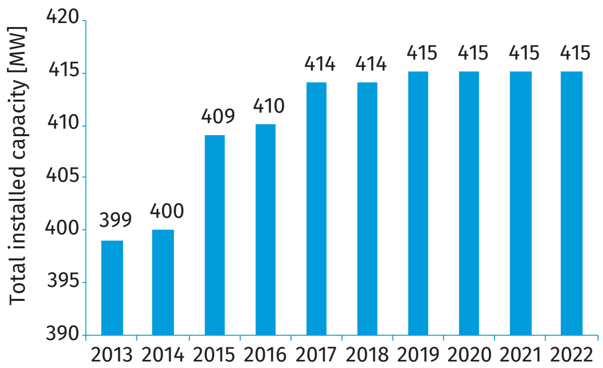
Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Portugal (MW)**



Sources: *WSHPDR 2019*,[10] DGEG,[13] *WSHPDR 2016*,[14] *WSHPDR 2013*[15]

SHP constituted approximately 6 per cent of all hydropower installed capacity as well as generation in 2020. As part of the PNAER, Portugal was aiming for an annual average generation of 1,511 GWh from SHP by 2020, corresponding to a total installed capacity of 750 MW from 250 plants.[10] As of 2021, this goal was unmet (Figure 4) and both actual installed capacity and annual generation reached approximately 55 per cent of their respective goals.

Figure 4. **Small Hydropower Capacities in Portugal in 2013–2022**



Source: DGEG[13]

Due to the country's topography and climate, most of the SHP plants are concentrated in the northern region which is characterized by a mountainous terrain and high annual precipitation. However, even in the rainy regions there is great seasonal variability in generation. During the dry summer months, hydropower plants in all regions experience a lower flow and electricity generation than during wetter months such as January and February.[13]

While no upcoming SHP projects in Portugal have been announced, the National Plan for Dams with High Hydropower Potential has been underway since 2007, defining the construction of 10 new large dams, some of which have already been cut. As of 2022, construction of the Tâmega hydropower complex is still undergoing and is expected to be finished by 2024. This project will be the largest hydropower project in Portugal and will comprise three plants with three water reservoirs on the Tâmega River in the northern region. When completed, total installed capacity will be 1,158 MW with 880 MW worth of pumped storage. The objective for this major project is to lessen energy dependence on imports from other countries while also moving towards the decarbonization of the electricity sector.[16]

RENEWABLE ENERGY POLICY

A key challenge for the energy sector of Portugal is to reduce energy dependence on imports, a goal which can only be achieved by developing renewable energy sources. Currently, renewable energy sources constitute a 31 per cent share of the energy sector and a 65 per cent share of the electricity sector.[4]

The PNAER 2013–2020 set targets for renewable energy sources. These targets included to have 31 per cent of final energy consumption be from renewable energy as well as to have 59 per cent of renewable energy sources in the electricity sector. Both of these targets were met on time with 33 per cent of renewable sources in final energy consumption and 65 per cent in the electricity sector in 2020.[17] Targets set in the country's National Energy and Climate Plan (PNEC) for 2030 include 47 per cent of renewable energy in final energy consumption, which was an interim plan towards the Road Map for Carbon Neutrality 2050 (RNC2050) plan. The RNC2050 establishes a pathway towards carbon neutrality by 2050, calling for a 99 per cent reduction in carbon emissions compared to 2005. The plan expects a 100 per cent reliance on renewable energy in the electricity sector to be done by heavy investments in all renewable energy sources, but especially in wind and solar power. The end of using coal for electricity is anticipated to be around 2029 and gas in 2040.[18] To facilitate the transition on the electricity grid, all renewable energy with the exception of hydropower above 30 MW has non-discriminatory priority. A framework for a feed-in-tariff (FIT) existed up until 2012, but this has since been dismantled and new plants are to be remunerated in the wholesale electricity market.[19]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

There is no regulation published on establishing the residual flow. Yet, there are indications that the ecological flow in Portugal should be, on average, 5–10 per cent of the modular flow. Also, this flow should be variable during the year to enable a better adjustment to the differences in the natural hydrological regime and to the spawning seasons. The residual flow would be the sum of the ecological flow with the flow necessary for the existing uses such as irrigation and water supply.[10]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Portugal is in a slow stage of development of its SHP sector with only a few power plants being developed in the last decade. Major barriers include:

- A lengthy, costly and unpredictable licensing procedure, which can take, on average, between 3 and 11 years;
- Legal constraints, particularly in regard to more stringent environmental requirements, such as the Water Framework Directive, can lead to a limitation of the technical characteristics and potentially the profitability of a project;
- Inadequate financial incentives such as FITs;
- Limitations on energy exports are an obstacle to the increase of renewable energy sources.

Major enablers for SHP include:

- There is still untapped potential availability in the country;
- SHP is socially preferred over large dam construction due to reduced environmental and economic impacts;
- A liberalized market allows any company to enter the industry to generate electricity;
- With the ambitious aspiration to have a fossil fu-

el-free electricity sector in less than 20 years, SHP can be a key tool towards this goal as it has lower start-up costs and faster construction times than large projects;
- The political environment is supportive and committed to increasing the share of renewable energy in the mix.

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Serbia

Slobodan Cvetković and Rastislav Kragić, independent experts

KEY FACTS

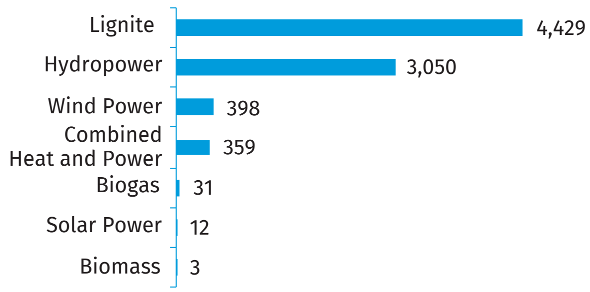
Population	6,945,235 (2019)[1]
Area	88,509 km²[2]
Topography	The northern part of Serbia is characterized by plains lying at elevations of up to 100 metres above sea level. The central part of the country is covered in hills and mountains, belonging to the Dinaric Alps, the Carpathian Mountains and the Rhodope Mountains. Important mountains in Serbia include Kopaonik, Stara Planina, Tara, Zlatibor, Golija, Suva Planina and Zlatar. The highest point in the country is Đeravica (2,656 metres) in the Prokletije Mountains.[2,3]
Climate	The climate of Serbia is predominantly continental, with local diversity due to geographic location, relief, terrain exposition, presence of rivers, vegetation and urbanization. The south-western part of the country includes both the Mediterranean and continental climates. The climate of Serbia is characterized by warm summers and cold winters, with an average annual temperature range of over 22 °C.[2]
Climate Change	The current trend of average annual temperature increase in Serbia is 0.6 °C per 100 years. The estimated rate of decrease of annual surface flows is 30 per cent per 100 years, but varying depending on the region. The smallest changes in surface flows are expected in the south-western part of the country, while the biggest decline is expected in the eastern part.[2]
Rain Pattern	The precipitation regime in Serbia is very heterogeneous on a regional scale. Annual precipitation ranges from approximately 500 mm in the north to over 1,000 mm in the mountain regions, with average precipitation nationwide of approximately 730 mm per year. Precipitation is highest in June and lowest in February and March.[2]
Hydrology	The majority of the territory of the Republic of Serbia (92 per cent) belongs to the Black Sea drainage basin, 5 per cent belongs to the Adriatic drainage basin and the remaining 3 per cent belongs to the Aegean basin. The Danube River flows for 588 kilometres through the territory of Serbia and along the border with Croatia and Romania. Other main rivers in Serbia are tributaries of the Danube, including the Sava (flowing from the west) and Tisa (flowing from the north). The Drina River, on the border with Bosnia and Herzegovina, is the biggest tributary of the Sava River. The longest river flowing exclusively through the territory of Serbia is the Velika Morava River, with a total length of 185 kilometres.[3]

ELECTRICITY SECTOR OVERVIEW

The total installed capacity of Serbia in 2020 was 8,285 MW (excluding the installed capacity of the Autonomous Province of Kosovo and Metohija), of which 4,429 MW (53 per cent) was provided by lignite thermal power plants, 3,050 MW (37 per cent) by hydropower plants, 398 MW (5 per cent) by wind power plants, 359 MW (4 per cent) by combined heat and power (CHP) plants and the remaining 49 MW (less than 1 per cent) by other energy sources, including solar power, biomass and biogas (Figure 1).[4]

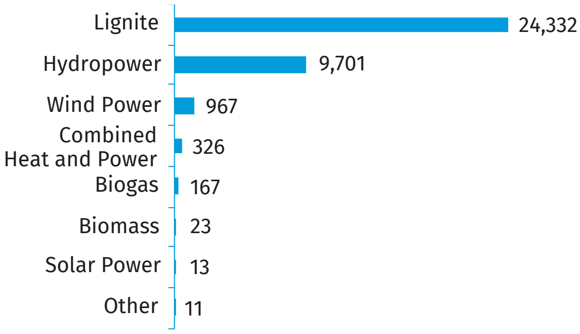
Generation of electricity in Serbia in 2020 reached 35,540 GWh, of which coal-fired thermal power plants produced 24,332 GWh (68 per cent), hydropower plants 9,701 GWh (27 per cent), wind power plants 967 GWh (3 per cent), CHP plants 326 GWh (1 per cent) and biomass, biogas, solar power and other sources provided a combined total of 214 GWh (less than 1 per cent) (Figure 2).[4] In 2020, Serbia imported 5,002 GWh of electricity and exported 5,943 GWh.[5]

Figure 1. **Installed Electricity Capacity by Source in Serbia in 2020 (MW)**



Source: AERS[4]

Figure 2. **Annual Electricity Generation by Source in Serbia in 2020 (GWh)**



Source: AERS[4]

Access to electricity in Serbia is 100 per cent in both urban and rural areas.[6] Electricity consumption in 2020 amounted to 29,039 GWh, of which household consumption accounted for 13,718 GWh (47 per cent).[4]

In line with its goal of full membership in the European Union (EU), the Republic of Serbia ratified the Energy Community Treaty with the EU in 2006, committing to transposing EU legislation on the energy sector.[7]

The basic law regulating the electric power sector in Serbia is the Energy Law, first adopted in 2004 and with significant amendments passed in 2011, 2014 and 2021.[8,9] Among other changes, the aforementioned amendments implemented the unbundling of the public energy company Elektroprivreda Srbije (EPS) into separate companies individually responsible for the generation, transmission and distribution of electricity. EPS is the largest power producer in Serbia. The transmission system operator (Elektromreža Srbije) and the distribution system operator (Elektrodistribucija Srbije), previously part of EPS, currently operate as independent entities.

The electricity system of Serbia is controlled by an independent regulatory body, the Energy Agency of the Republic of Serbia (AERS). Electricity suppliers, which can be private or state-owned companies, trade on the free electricity market. Producers and final customers of electricity are free to choose their supplier and contract electricity purchases.

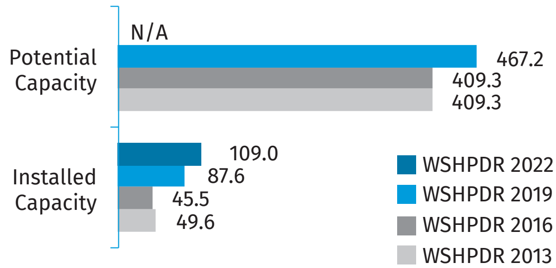
Average electricity tariffs for end users with low-voltage connections in Serbia in 2020 were 7.14 RSD/kWh (0.068 USD/kWh) for households, 6.80 RSD/kWh (0.065 USD/kWh) for public lighting and 9.39–12.21 RSD/kW (0.09–0.12 USD/kWh) for 0.4 kV stage I and stage II connections (before VAT). Tariffs for households with an annual consumption of 2,500–5,000 kWh were 0.074 EUR/kWh (0.08 USD/kWh).[4]

SMALL HYDROPOWER SECTOR OVERVIEW

While the term "small hydropower (SHP) plant" is not used in any energy legislation in Serbia, the Decree on Incentive Measures for Privileged Electric Power Producers, adopted in 2013, established incentive measures for hydropower plants of up to 30 MW installed capacity.[10]

As of December 2020, the total installed capacity of SHP plants of up to 10 MW in Serbia was 109 MW from 138 plants.[4,11] While the *World Small Hydropower Development Report (WSHPDR) 2019* overestimated installed SHP capacity in Serbia, the installed capacity of SHP plants in the country has increased since 2019 as a result of the commissioning of new plants. Up-to-date figures on potential SHP capacity in the country are not available (Figure 3).[12]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Serbia (MW)**



Source: AERS,[4] MRE,[11] *WSHPDR 2019*,[12] *WSHPDR 2013*,[13] *WSHPDR 2016*[14]

Note: Data are for SHP up to 10 MW.

Estimates of SHP potential in Serbia are largely based on results of studies conducted in the late 1980s, including the Cadastre of Small Hydropower Plants published in 1987. These studies identified a total of 870 potential sites in Central Serbia and Vojvodina for SHP up to 10 MW, with a total capacity of 467.2 MW.[15,16,17,18] However, the studies did not consider environmental, social, and economic criteria as well as the cumulative impacts of SHP plants. Additionally, the impact of SHP plants on the environment has been a topic of increasing concern for environmentalist groups in Serbia and the public at large.[18] Consequently, a project to produce a new cadastre of potential SHP sites that would account for these factors was launched in 2016. The project has been endorsed by the European Commission and is still in the process of being implemented.[19]

The installed capacity of small hydropower plants in Serbia has increased in recent years, but no SHP plants of above 10 MW capacity have been built since 2010.[11] Provisions in the Energy Law have established the Privileged Power Producer (PPP) status for renewable energy producers, enabling PPPs to access feed-in tariffs (FITs) and other incentives, as well as the Preliminary Privileged Power Producer (PPPP) status for developers who commit to constructing renewable energy projects within three years of being granted the PPPP status and who are then eligible to access incentives including FITs at the level set when receiving the status.[8] As of December 2020, 121 SHP plants up to 10 MW, with a total capacity of 77.27 MW, had been granted PPP status.[11] A list of the most recently commissioned plants is displayed in Table 1.

Table 1. **List of Selected Existing Small Hydropower Plants in Serbia**

Name	*Location*	*Capacity (MW)*	*Launch year*
Šljivovica	Priboj	1.300	2021
Jovanovići	Arilje	0.515	2021
Ravni	Uzice	0.470	2021
Lozno	Novi Pazar	0.320	2021
Tlamino	Bosilegrad	0.260	2021
Rogopeč 1	Ivanjica	1.763	2020
Reka	Bosilegrad	0.815	2020
Manjak	Vladicin Han	0.470	2020
Duavica	Vranje	0.341	2020
Pršići	Brus	0.138	2020

Source: MRE[20]

Plans for the construction of an additional 50 SHP plants up to 10 MW were laid out in the National Renewable Energy Action Plan (NREAP) of Serbia in 2013.[19,21] Several ongoing SHP projects recently granted the PPPP status are listed in Table 2.

Table 2. **List of Selected Ongoing Small Hydropower Projects in Serbia**

Name	*Location*	*Capacity (MW)*	*Planned launch year*
Brusnik	Arilje	1.264	2024
Jeliće	Tutin	0.128	2024
Piskanja	Raska	2.800	2023
Pročovci 3	Trgoviste	0.910	2023
Bučalo	Vranje	0.240	2022

Source: MRE[20]

RENEWABLE ENERGY POLICY

In 2014, Serbia introduced a new system of support measures for projects for electricity generation from renewable energy sources (RES) through secondary legislative documents building on the existing Energy Law. These documents outline conditions for granting the FIT and the commercial and procedural provisions for producing electricity from RES. These provisions included the definition of RES; capacity limits for FIT eligibility as well as the period of eligibility, set at 12 years from the FIT application process; and the disbursement procedure for FITs, based on a specific contract between the electricity producer and the public supplier.

The FIT incentive system for generation from RES was in force between 2010 and 2021. During this period, 272 projects with a total installed capacity of 520 MW received the PPPP status.[20] In April 2021, the Parliament of Serbia adopted the new Law on the Use of RES, which among other measures defined a system of market premiums as the primary measure of support for RES projects, largely replacing the FIT system. The market premium is paid on top of the sale price of electricity on a per kWh basis. Unlike the FIT, the market premium is not set in advance but is arrived at through a system of auctions and changes continually.

FITs will remain as the support measure for small plants, defined as those with a capacity of less than 500 kW (less than 3 MW in the case of wind farms).[22] As of 2020, FITs for SHP plants up to 200 kW of capacity were 0.133 EUR/kWh (0.150 USD/kWh and for SHP plants of 200–500 kW they were 0.112-0.133 EUR/kWh (0.126-0.150 USD/kWh).[4]

Additionally, the new RES law allows households and companies to produce electricity as prosumers by producing electricity from solar panels and other RES for own use and for sale to the electricity market. Finally, provisions in the new RES law have prohibited the construction of hydropower plants in protected natural areas and recognized new forms of renewable energy, including "green" hydrogen.[22]

The Republic of Serbia ratified the Green Agenda for Western Balkans with the EU in Sofia in November 2020. Serbia has obliged to implement activities outlined in the Agenda, including actions on climate change, energy, mobility, circular economy, depollution, sustainable agriculture and food production, and biodiversity.

In March 2021, the Parliament of Serbia adopted the Law on Climate Change. This law established the system for limiting greenhouse gas (GHG) emissions; the adoption of a low-carbon development strategy and the procedures for monitoring, reporting and continual improvement of the strategy; the programme for adaptation to climate change; and a system of issuing permits for GHG emissions to the plant operators, including monitoring, reporting, verification and accreditation of verifiers, administrative fees, supervision and other issues relevant to limiting GHG emissions.[23] Serbia is additionally preparing a National Energy and Climate Plan for 2021–2030 with a vision to 2050, as well as an Energy Development Strategy until 2040 with a projection to 2050.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Licensing requirements for the construction and operation of SHP plants in Serbia include a location permit, construction permit, water permit, operating permit, energy licence and the right to engage in power generation.[24] An environmental impact assessment (EIA) may be required for SHP plants exceeding 2 MW or those situated in a protected natural area and additional supporting documents may also be required during the associated administrative procedures. Environmental issues must be considered in the planning, construction and utilization of SHP plants, as outlined in relevant legislation harmonized with the EU regulatory frameworks including the Law on Nature Protection, Directives on the Environmental Impact Assessment and the Strategic Environmental Assessment, the Water Framework Directive, Council Directive 92/43/EEC on the conservation of natural habitats and of wild fauna and flora, Nature 2000 and the Aarhus Convention. This body of legislation collectively mandates that environmental impacts including changes in water quality, sedimentation, impacts on wildlife, landscape and the flow regime of the watercourse must all be taken into consideration during development projects such as SHP construction.[25] A regulation for determining the minimum sustainable flow in rivers according to the Law on Waters has not yet been adopted.[26]

Finally, in line with the Aarhus Convention, the public must be involved in the planning, assessment and decision-making regarding the operational regime of SHP plants. In the past, environmental damage attributed to the construction and operation of SHP plants in Serbia, stemming from poor enforcement of regulations, has resulted in protests by local communities, including those targeting SHP plants at Stara Planina and Rakita, among others, and leading to a prohibition on SHP construction in protected natural areas by the Law on the Use of RES and amendments to the Law on Nature Protection.[22,27,28] Thus, the wider eco-social context of Serbia must be systematically taken into consideration as part of SHP construction and operation.

COST OF SMALL HYDROPOWER DEVELOPMENT

Total investment costs for SHP plants in Serbia typically consist of the following elements[29]:

- preparation and construction work (40–70 per cent of total cost);
- cost of hydromechanical equipment (1–2 per cent);
- cost of electro-mechanical equipment of (20–40 per cent);
- cost of connection to the electric power system (up to 20 per cent);
- other costs, including cost of administration, purchase, design and supervision (5–10 per cent).[29]

Most of the equipment installed as part of the SHP plant construction process in Serbia is not manufactured locally and must be imported.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Models of the impact of climate change on discharge in mountainous catchments in Serbia predict significant seasonal shifts in the monthly precipitation volume and discharge under both moderate and extreme climate change scenarios, relative to the 1971–2000 baseline period. In particular, while no significant changes are predicted on an annual basis, increases in precipitation and discharge in the winter months of up to 50 per cent are possible by the end of the 21st century, increasing the flood risk during this period. Corresponding reductions of discharge and precipitation during the warm period are considered likely to impact several economic sectors, including hydropower generation.[30]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Since 2019, SHP projects have encountered delays in implementation and increased scrutiny from the public and non-governmental organizations. The obstacles to SHP development in Serbia include the following:

- Long and complicated administrative procedures related to the issuance of necessary permits for SHP plants;
- Lack of supervision and control from authorities during the construction of SHP plants and their operational regime;
- Lack of corresponding expertise within authorities, especially at the local level;
- Previous failures in construction and operational work of SHP plants leading to the endangerment of wildlife such as fish and birds, negative impacts on the flow regime and landscape, and other negative outcomes;
- The lack of public consultation and exchange of information between all stakeholders, including the local and regional authorities, the investor, the local community, and the non-governmental sector, among others, and the resultant resistance to SHP development from civil society organizations and the public.

The main opportunity for future SHP development in Serbia lies in their installation on multipurpose hydro-technical systems, where such development is appropriate. These include:

- Outputs for environmental and regulatory flows on non-powered dams;
- Elements of pressurized water systems such as pressure break tanks, where installation of SHP plants is conducive to the pressure regulation function of the system.

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Slovenia

International Center on Small Hydropower (ICSHP)

KEY FACTS

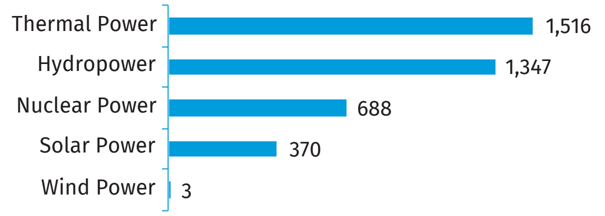
Population	2,102,419 (2020)[1]
Area	20,271 km²[2]
Topography	The terrain of Slovenia is predominantly elevated and is divided into four major regions. The largest and highest region is the Alps situated in the north and north-west. It is there where the highest peak, Triglav at 2,864 metres, is located. Just south of the Alps is the Karst Plateau region, featuring several caves and underground rivers. In the north-east and east of the country are the Subpannonia lowlands with rolling hills. The smallest region is the Slovene Littoral along the south-western border with Italy, featuring river valleys and a small rocky coastline.[2]
Climate	Slovenia has a temperate climate with variations between regions. The northern mountainous region is cooler with continental influences. Winters are cold, with typically below freezing temperatures, and summers are cool, with temperatures remaining close to 20 °C. The south is warmer with Mediterranean influences. Summers are hot with an average temperature of 27 °C in July and winters are mild, rarely dropping below 10 °C.[2]
Climate Change	There have been notable effects of climate change in Slovenia in the past 50 years. Since 1961, the average temperature has increased by 1.7 °C, which is more than the European average. Additionally, annual precipitation has decreased by between 10 and 15 per cent with a 55 per cent decrease in snow depth. By 2100, temperatures are expected to increase by an additional 1–4 °C, especially during winters. Precipitation patterns are expected to continue changing, but the exact amounts are difficult to predict. Generally, rainfall could decrease during summer and autumn and increase during winter and spring.[3]
Rain Pattern	Rainfall varies by region and season. Rainfall is the highest in the western Alps, reaching over 3,000 mm per year, central regions have approximately 1,400 mm per year and the south-eastern region has the lowest rainfall, with an annual average of 800 mm. Rainfall is highest during the autumn and winter months for almost all parts of the country, except for in the east, where the most rainfall happens during the summer months.[3]
Hydrology	Many of the rivers in Slovenia begin in the north and flow south-east to empty into the Danube River and ultimately, the Black Sea. Major rivers include the Drava and Mura in the north-east that begin in Austria, the Sava that begins in the north-western Alps and cuts south-east through the central region and the Soča, the only major river that flows south-west and empties into the Gulf of Venice. Rivers typically have a strong, fast flow due to the country's steep slopes.[2]

ELECTRICITY SECTOR OVERVIEW

In 2020, total installed capacity in Slovenia was 3,924 MW. Of this, thermal power accounted for 1,516 MW (39 per cent), hydropower for 1,347 MW (34 per cent), nuclear power for 688 MW (18 per cent), solar power for 370 MW (9 per cent) and wind power for 3 MW (0.08 per cent) (Figure 1).[4] The fastest growing source of energy has been solar power, accounting for 87 per cent of newly connected capacity between 2019 and 2020.[5]

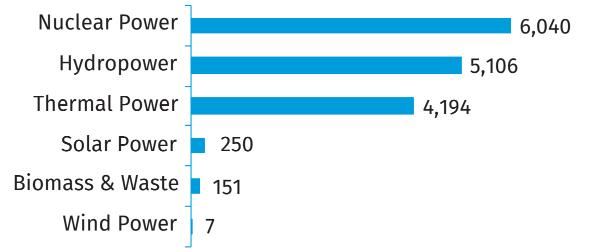
In 2020, total electricity generation in Slovenia was 15,748 GWh, of which 35 per cent was using renewable energy. Nuclear power generated 6,040 GWh (38 per cent), hydropower 5,106 GWh (32 per cent), thermal power 4,194 GWh (27 per cent), solar power 250 GWh (2 per cent), biomass and waste 151 GWh (1 per cent) and wind power 7 GWh (0.04 per cent) (Figure 2). In the same year, Slovenia imported 7,120 GWh, mostly from Austria, and exported 6,103 GWh, mostly to Croatia and Italy. Total consumption of electricity by end users was 12,506 GWh, of which 8,947 GWh was consumed by all types of businesses and 3,559 GWh was consumed by households. Losses due to transport in transmission and distribution systems were 849 GWh.[5] The electrification rate of Slovenia is 100 per cent.

Figure 1. **Installed Electricity Capacity by Source in Slovenia in 2020 (MW)**



Source: Ministry of Infrastructure[4]

Figure 2. **Annual Electricity Generation by Source in Slovenia in 2020 (GWh)**



Source: Energy Agency[5]

The Energy Agency is the country's market regulator responsible for ensuring the transparency of market operations, determining methodologies for the energy sector and issuing guarantees of origin and commercial green certificates for the production of electricity from renewable energy sources. Borzen is the market organizer tasked with promoting the development of the country's electricity market and market mechanisms in accordance with the European Union (EU) guidelines. It also contributes to the proper functioning of the country's power system, the alignment of Slovenian and EU legislation and integration of the country's electricity market into the integrated European electricity market.[6]

In Slovenia, while the sector allows private companies to supply electricity, the large electricity producers are owned by the state. The majority of the country's power plants are owned by either of the two publicly owned parent companies, Holding Slovenské Elektrárne (HSE) and GEN Energija. The one nuclear power plant is owned by Nuklearna Elektrarna Krško (NEK), which is equally shared between Slovenia and Croatia.[7] Small electricity producers (up to 10 MW), distribution companies and energy market suppliers can be publicly, privately or mixed owned. The transmission system is fully operated by the state-owned company ELES. The total length of the transmission electric network in Slovenia is 2,859 kilometres. It connects major producers, big consumers and neighbouring countries Austria, Croatia and Italy, with plans to include Hungary in the near future.[5] The total length of the distribution network is approximately 65,000 kilometres (70 per cent is a low-voltage network), which efficiently covers the country's territory and also reaches existing small producers.[6]

The electricity sector is governed through the Energy Act of 2014, which was last amended in 2015. The act replaced the previous one from 2007 in order to properly implement EU directives and comply with new decisions of the Constitutional Court of Slovenia regarding how network charges are determined. The current law clarifies the principles of energy policy, energy market operation rules and manners, measures to achieve a secure energy supply and improve energy efficiency and energy saving. It also promotes the usage of renewable energy sources, giving further framework for a support scheme for such energy production that was initially introduced in 2009.[5,6]

In the decade that the support scheme has been in operation, 3,839 facilities have been included in it. The large majority, or over 3,200, has been solar power plants, but has also included various hydropower, biomass, wind power and cogeneration of combined heat and power (CHP) plants. In 2020, 962.2 GWh of electricity was generated by the plants included in the support scheme and an additional 44.62 MW was added to the grid due to new projects supported by the scheme. Compared to 2019, electricity production by plants included in the support scheme increased by 1.5 per cent and compared to 2018, by 2.6 per cent.[5]

The electricity market of Slovenia was opened on 1 July 2007. As such, electricity prices for general industrial and household consumers now depend on the wholesale market in Slovenia and in the EU. In 2020, Slovenia joined the interregional day-ahead market with Austria, Croatia and Italy as well as the single intraday market with Austria and Croatia, with plans to do so with Italy in the future. Wholesale electricity is traded quickly and easily through these markets, ultimately determining the base prices. In 2020, the average wholesale price for electricity was 37.55 EUR/MWh (39 USD/MWh). Within the country, electricity prices for final consumers include the base price, a network charge, levies, excise duties and a value-added tax (VAT). The average final price for the typical household in 2020 was 0.157 EUR/kWh (0.16 USD/kWh). The final price for businesses ranged between approximately 0.06 EUR/kWh (0.07 USD/kWh) and 0.16 EUR/kWh (0.17 USD/kWh) depending on type of business customer and usage.[5]

SMALL HYDROPOWER SECTOR OVERVIEW

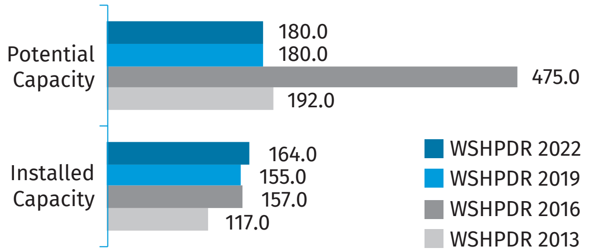
This chapter is using the definition of small hydropower (SHP) as hydropower plants of up to 10 MW. However, there are different definitions of SHP in Slovenia. From the water management perspective, SHP is defined as a hydropower plant with an installed capacity of less than 10 MW. From the perspective of electricity generation from renewable energy sources, there are four categories:

- Micro: less than 50 kW;
- Small: between 50 kW and 1 MW;
- Medium: between 1 MW and 10 MW;
- Large: more than 10 MW.[6]

The installed capacity of SHP plants in Slovenia in 2020 was 164 MW.[4] The total technically and economically feasible potential of SHP in Slovenia is estimated to be approximately

180 MW, indicating that 91 per cent has already been developed.[6] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019,* total installed capacity has increased by 9 MW and potential has remained the same (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Slovenia (MW)**



Sources: Ministry of Infrastructure,[4] *WSHPDR 2019,*[6] *WSHPDR 2016,*[8] *WSHPDR 2013*[9]

Between 2019 and 2020, approximately 0.95 MW of SHP was newly connected to the grid, accounting for almost 2 per cent of all newly connected capacities for the year. The majority of SHP in Slovenia is produced by small electricity production companies and in 2020, these companies accounted for 127 MW of the installed SHP.[5] The major companies, HSE and GEN Energija, typically operate large hydropower but there are a few SHP plants owned by them as well. While it is difficult to obtain up-to-date data about the small production companies and their projects, the newest SHP plant that is operated by Dravske elektrarne Maribor, owned by HSE, was the 0.023 MW Rogoznica plant commissioned in 2019.[10]

The last comprehensive analysis and planning of potential SHP projects on the national scale was carried out by the Energy Directorate in 2007. The study identified 33 SHP sites with capacities of 1–10 MW and 6 sites with smaller capacities. Most of these sites, however, are not in line with the objectives of the Water Framework Directive (e.g., achieving good ecological status) and are located in protected areas of the Natura 2000 EU network.[6]

The National Renewable Energy Action Plan 2010–2020 (NREAP 2010–2020) set the goal of increasing the installed capacity of SHP plants to reach 177 MW by 2020, a goal that is 93 per cent reached.[11] The major challenge for SHP development is to harmonize renewable energy and the ecological objectives. Slovenia has many sites protected under Natura 2000, which stipulates special care to be taken in regards to the environment at these sites, often preventing infrastructure development including hydropower plants. The regulatory basis does, however, include the guidance for the Alpine Space and Danube Basin with the consideration of Article 4.7 of the Water Framework Directive and Article 6.4 of the Habitats Directive. Both the Water Framework Directive and the Habitats Directive offer the clause that, for new development to take place, public interest should be considered and the overall sustainable development benefits of new electricity production must outweigh the environmental damage and that such societal benefits would not be achieved in a different, more ecologically sustainable way.[12] The main principle to be followed is that the higher the ecological value of a water stretch (waterbody), the higher the energy output should be. Therefore, regulations favour the development of larger hydropower.

Consequently, the national plans for the upcoming decades do not strongly push for SHP development. The Integrated National Energy and Climate Plan of 2020 states that priority should be given to upgrading and modernizing existing SHP plants. However, it also foresees a possible increase of SHP installed capacity to reach a total of 177 MW by 2040. The same plan foresees a much higher increase of large hydropower installed capacity, possibly reaching up to 1,979 MW by 2040.[13] Similarly, development of SHP is not addressed in the Slovenian Network Development Plan 2021–2030, which outlines four scenarios of future energy development with varying levels of optimism for renewable energy shares. Most scenarios envisage an increase in large hydropower, while none of the scenarios include SHP. The fourth scenario includes the largest increase of hydropower, foreseeing an additional 562 MW of large hydropower spread between five hydropower plants to be incorporated into the grid by 2030.[5]

Despite the fact that no explicit plans to expand SHP exist in Slovenia, there is still feed-in financial support provided to SHP projects through two schemes—operating support (OS) and guaranteed purchase (GP). Both are provided for a period of 15 years for new projects. The level of support is defined each year and does not affect plants which are already included in the support scheme (Table 1).[14]

Table 1. **Financial Support of Hydropower Projects in 2020**

Scale of the project	*Tariffs (EUR/MWh (USD/MWh))*	
	Operating support	*Guaranteed purchase*
< 50 kW	53.44 (55.88)	105.47 (110.28)
50 kW – 1 MW	40.58 (42.43)	92.61 (96.83)
1 MW – 10 MW	27.89 (29.16)	82.34 (86.09)
> 10 MW	22.12 (23.22)	N/A

Source: Borzen[14]

RENEWABLE ENERGY POLICY

In compliance with the EU Directive 2009/28/EC, Slovenia published the National Renewable Energy Action Plan (NREAP) in 2010, which covered topics such as the national policy on renewable sources of energy, the expected gross final energy consumption in the period between 2010 and 2020, individual targets and trajectories for each renewable energy source, measures for achieving the binding target shares of renewable energy sources and an estimation of the costs of carrying out measures as well as of the impacts on the environment. The plan defined the target of 25 per cent of renewable energy in final energy consumption by

2020. The actual renewable energy share in final energy consumption in 2020 was 22 per cent, approaching the goal but not meeting it. Specific renewable energy targets for annual generation included for hydropower to generate 5,121 GWh, biomass and waste 676 GWh, solar power 139 GWh and wind power 191 GWh and for renewable energy to reach 39.1 per cent of total electricity generation.[15] Actual generation in 2020 shows that the solar power target was greatly surpassed, the biomass and waste and wind power fell considerably short of their targets and hydropower reached 99 per cent of its target. Overall renewable energy electricity generation missed the target by 4 percentage points.[5]

The competent authority responsible for the energy sector is the Energy Directorate within the Ministry of Infrastructure. In the NREAP measure No. 38 "Proactive role of the state in identifying environmentally acceptable locations for exploiting hydropower potential", it is stated that the Ministry of the Environment and Spatial Planning will ensure the processing of already received petitions to initiate the procedure for allocating water rights for the SHP projects. The Ministry of the Economy will undertake a study of the costs and benefits of existing SHP plants, as a basis for sustainable criteria, wherein it takes account of the environmental, social and economic impacts.[14]

More recently, the country has adopted the Development Strategy 2030 in 2017 and the Integrated National Energy and Climate Plan in 2020, both of which lay down the outlook for the energy sector for the upcoming decades. The key objectives of these plans include for renewable energy to reach 27 per cent in final energy consumption and 43 per cent in electricity generation by 2030. The plans also seek to improve energy efficiency and security to lead the path towards a decarbonized economy. Individual targets for renewable energy include for generation of solar power to reach 1,866 GWh in 2030 and 5,361 GWh in 2040, wind power to reach 248 GWh in 2030 and 577 GWh in 2040 and hydropower to reach 4,966 GWh in 2030 and 7,014 GWh in 2040. The future of biomass depends on whether installed capacity of it can transform to be purely biomass or remain as a cogeneration input in existing thermal power plants.[13]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The major barriers to SHP development in Slovenia include:

- A lack of the efficient collaboration between sectors, with each sector following its own objectives and not properly applying the principles of the sustainable development;
- A lack of human and financial resources, which translates into inadequate data management, lack of supervision and stronger position of water management objectives in spatial planning and land use, inadequate maintenance of the water infrastructure and watercourses and also unclear and non-straightforward decision making;
- There is mistrust surrounding new SHP development, especially in the nature protection sector, since many of the existing SHP plants do not follow obligations of ensuring the environmental flow and meeting other requirements related to the aquatic ecosystem protection;
- There exists inadequate technical, economic, environmental and risk awareness on the investors' side, especially the smaller ones, who are not always aware of the fact that investment in SHP projects with full consideration of all technical, safety and environmental aspects can require considerable time and financial resources.[6]

The major enablers for SHP development in Slovenia include:

- There are feed-in financial incentives such as operating support or guaranteed purchase offered;
- Total SHP potential capacity has not yet been reached, leaving room for feasible SHP development;
- According to the national plans, there is opportunity in upgrading and modernizing existing SHP plants.

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Spain

Cayetano Espejo Marín and Ramón Garcia Marín, Universidad de Murcia; and Laura Stamm, International Center on Small Hydropower (ICSHP)

KEY FACTS

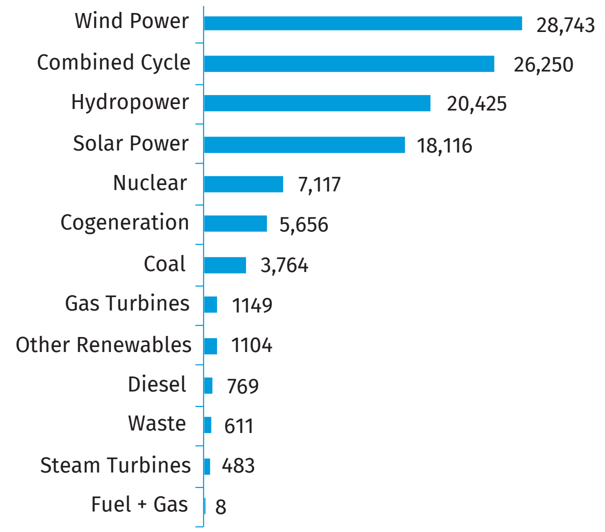
Population	47,351,567 (2020)[1]
Area	505,000 km^2 [2]
Topography	Spain has a diverse terrain characterized by a central plateau surrounded by various mountain ranges. The Meseta Central Plateau, with an average elevation ranging from 500 metres to 700 metres above sea level, is divided in the middle by the Central Sierra Mountains. To the north of the plateau are the Cantabria Mountains, to the north-east and east is the Iberian Cordillera and to the south are the Sierra Morena Mountains. The Pyrenee Mountains run along the north-eastern and eastern boundaries of the country bordering with France and the Baetic Cordillera runs parallel to the southern coast. Coastal plains run along the Mediterranean Sea to the south. The Balearic Islands in the Mediterranean are a part of the Baetic Cordillera and the Canary Islands in the Atlantic Ocean are of volcanic origin. The highest point on the mainland is Mulhacen at 3,481 metres and the highest point of the whole territory is Teide Peak on the Canary Island of Tenerife at 3,718 metres.[2]
Climate	The climate varies between regions due to the peninsula's size and diverse terrain. The north of Spain has a temperate maritime climate influenced by the Atlantic Ocean with cool winters, warm summers and heavy rainfall. Winters remain mild along the coasts but are cold in high elevations. The central region has a temperate continental climate influenced by the Mediterranean with mountains creating pockets of humid and arid zones. The south has a warm, Mediterranean climate occasionally affected by the hot, dry North-Saharan airstream. Summers are hot, often reaching above 30 °C and winters are mild.[2,3]
Climate Change	Climate change is expected to affect the country's average temperatures and rainfall. There has been a noticeable increase in average and minimum temperatures since the 1970s in most of the country. In the southern plateau region, maximum temperatures have also increased with significance, up to 1.62 °C. Warming is expected to continue, especially in the summers and in inland regions and by the end of the 21st century, temperatures are expected to have increased by between 3 °C and 6 °C. Rainfall patterns are expected to become more extreme. In the northern rainy zone precipitation will most likely further increase and in the southern semi-arid zone precipitation will most likely further decrease.[3]
Rain Pattern	Average annual rainfall in Spain has a wide range and can be categorized into three zones. The rainy zone covers the northern and north-eastern regions where annual rainfall is above 1,000 mm, surpassing 2,000 mm in some areas. The dry zone covers most of the country, covering the Meseta Central Plateau region and spanning east to the coast and border with France. Average rainfall in this zone is approximately 500 mm per year. Semi-arid zones receive the least amount of rainfall and can be found in the south of the mainland near the coast and much of the Canary Islands. Average annual rainfall in the semi-arid zones is less than 300 mm and, in some parts, barely reach 150 mm.[3]
Hydrology	There are approximately 1,800 rivers in Spain, though many stay dry for much of the year. There are five major rivers, most of which begin in the interior mountains and flow westwards to empty in the Atlantic Ocean. The Tagus, Douro and Guadiana Rivers begin in Spain but flow through Portugal to reach the ocean while the Guadalquivir remains in the country's territory to reach the Atlantic in the south. The Ebro River is the longest river within the country's boundaries and is the only major river that empties into the Mediterranean. Beginning in the high altitudes of the north-eastern Pyrenee Mountains and flowing southwards, it is also the river that has the most continuous flow regardless of the season.[2]

ELECTRICITY SECTOR OVERVIEW

As of April 2022, total installed capacity in Spain was 114,196 MW comprising several sources. Wind power accounted for just above 25 per cent (28,743 MW), combined cycle accounted for 23 per cent (26,250 MW), hydropower for 18 per cent

(20,425 MW), solar power for 16 per cent (18,116 MW), nuclear for 6 per cent (7,117 MW), cogeneration for 5 per cent (5,656 MW), coal for 3 per cent (3,764 MW), gas turbines for 1 per cent (1,149 MW), other renewable sources for 1 per cent (1,104 MW) and the remaining 2 per cent was split between diesel (769 MW), waste (611 MW), steam turbines (483 MW) and fuel+gas power plants (8 MW) (Figure 1).[4] Of total capacity, 57 per cent was from renewable sources and 43 per cent from non-renewable sources. Compared to the installed capacity at the year-end of 2020, the total has increased by 3,371 MW and the renewable energy share has increased by 3 per cent, primarily as a result of the increase of solar power by more than 4,100 MW, the increase of wind power by more than 1,200 MW and the decrease of coal by approximately 1,900 MW.[4]

Figure 1. **Installed Electricity Capacity by Source in Spain in 2022 (MW)**

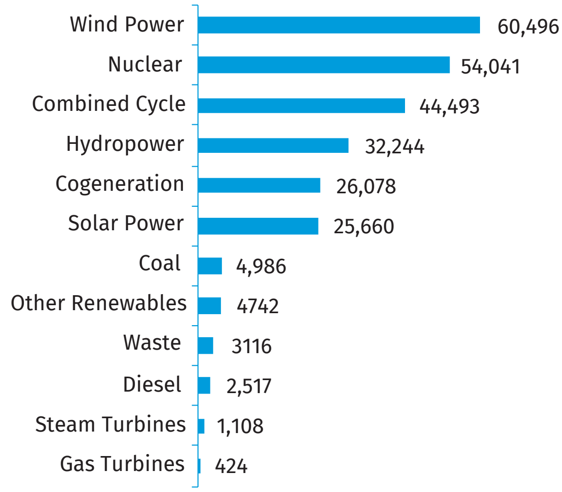


Source: REE[4]

Total electricity generation in Spain for the year of 2021 was 259,905 GWh. Of the total, approximately 23 per cent was generated by wind power (60,496 GWh), 21 per cent by nuclear power (54,041 GWh), 17 per cent by combined cycle (44,493 GWh), 12 per cent by hydropower (32,244 GWh), 10 per cent by cogeneration (26,078 GWh), 10 per cent by solar power (25,660 GWh), 2 per cent by coal (4,986 GWh), 2 per cent by other renewables (4,742 GWh), 1 per cent by waste (3,116 GWh), 1 per cent by diesel (2,517 GWh) and the remaining 1 per cent was made up of steam turbines (1,108 GWh) and gas turbines (424 GWh) (Figure 2).[5]

The electricity sector in Spain is fully liberalized, a process that began with the Electric System Planning Law (LOSEN) of 1994 and completed with the Electricity Sector Law of 1997. This was in accordance with the European Union (EU) Common Standards Directive 96/92/EC, which was passed in 1996 calling for all EU members to liberalize their energy markets.[6] This allowed any company to generate or distribute electricity and for consumers to be able to choose their supplier. Although there are more than 300 electricity companies in the country, three major companies controlled over 65 per cent of the market share in 2019: Endesa (32 per cent), Iberdrola (24 per cent) and Naturgy (9 per cent).[7] All electricity transmission remains the responsibility of one company, the Red Eléctrica de España (REE), who manages the country's 44,687 kilometres of high-voltage lines.[8]

Figure 2. **Annual Electricity Generation by Source in Spain in 2021 (GWh)**



Source: REE[5]

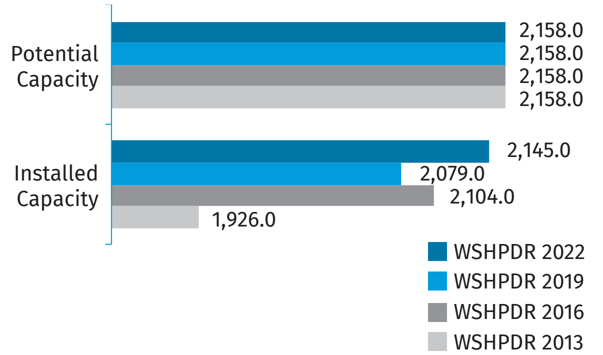
The Ministry of Ecological Transition and Demographic Challenge and the Secretariat of Energy within it oversees the energy sector as a whole and is responsible for implementing energy legislations and policies.[9] The National Commission of Markets and Competition (CNMC) is responsible for regulating the sector, supervising market competition and ensuring transparency for consumers. The CNMC also cooperates internationally as a member of the Council of European Energy Regulators (CEER) and represents Spain in the European Agency for the Cooperation of Energy Regulators (ACER).[10] The Iberian Electricity Market (MIBEL) includes both Spain and Portugal. Spot market trading is managed by the Iberian Market Operator of Spain (OMIE) and future market trading is managed by the Iberian Market Operator of Portugal (OMIP).[11]

The electrification rate in Spain is 100 per cent.[12] There are two types of markets that determine electricity tariffs and consumers are able to choose which market they would like to pay on. The free market is unregulated by the Government and prices are determined by the electricity company in which a fixed rate would be established on the consumers' contracts. On the regulated market, the Voluntary Small Consumer Price (PVPC) is offered to consumers with contracts of 10 kW or less and prices are changed hourly, fluctuating with supply and demand. Roughly half of the country's households choose the fixed rate and half choose to pay the PVPC, however, recently more households are beginning to switch to the fixed rate.[13] As of April 2022, the PVPC price was approximately 0.283 EUR/kWh (0.30 USD/kWh).[14] Since there are hundreds of electricity companies within the country, the free-market tariffs can vary greatly. The tariff offered by the country's largest company, Endesa, in 2022 was 0.23 EUR/kWh (0.24 USD/kWh).[15]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Spain is an installed capacity up to 10 MW. In 2021, the SHP installed capacity was 2,145 MW from 1,098 plants throughout the country.[16] The SHP potential is estimated at 2,185 MW.[11] In comparison with the *World Small Hydropower Development Report* (*WSHPDR*) *2019*, installed capacity has increased by 66 MW (3 per cent) and the SHP potential remained the same (Figure 3). The increase of installed capacity is due to an additional 39 MW in Andalusia, 8 MW in Galicia, 8 MW in the Basque Country, 4 MW in Castilla La Mancha, 4 MW in Castile and León, 4 MW in Catalonia and a decrease of 1 MW in Aragon since 2017.[16]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Spain (MW)**



Sources: *WSHPDR 2019*,[11] CNMC,[16] *WSHPDR 2016*,[17] *WSHPDR 2013*[18]

Most of the SHP activity in Spain is concentrated in four autonomous communities of the country: Galicia, Catalonia, Aragon and Castile and León. Together they represent almost 62 per cent of SHP installed capacity and over 70 per cent of SHP electricity generation in the country (Table 1).[16]

SHP development first entered Spain at the end of the 19th century and was a favourable form of power generation until its peak in the mid-20th century. In 1964 there were 1,740 SHP plants in the country, however, large hydropower was then seen as more economically beneficial. The popularity of SHP declined and plants were dismantled, so that by 1978, 735 SHP plants remained. SHP development made a comeback in the 1980s after the Energy Conservation Law 82/1980 was passed stating benefits of hydropower up to 5 MW. The same year a hydropower feasibility study was carried out that found in addition to what was already developed at the time, there was a 34,000 GWh potential for all hydropower, of which 6,700 GWh was untapped SHP potential.[19]

Table 1. **Installed Small Hydropower Capacity and Generation by Region in Spain in 2021**

Region	*Capacity (MW)*	*Share of total (%)*	*Generation (GWh)*	*Share of total (%)*
Andalusia	180	8.4	136	2.6
Aragon	257	12.0	633	12.1
Asturias	76	3.5	214	4.1
Canary Islands	1	0	3	0.1
Cantabria	72	3.4	184	3.5
Castilla La Mancha	127	5.9	363	7.0
Castile and León	258	12.0	626	12.0
Catalonia	289	13.5	798	15.3
Valencia	31	1.4	26	0.5
Extremadura	23	1.1	18	0.4
Galicia	521	24,3	1,545	29.7
La Rioja	27	1.3	72	1.4
Madrid	44	2.1	67	1.3
Murcia	14	0.6	47	0.9
Navarre	167	7.8	348	6.7
Basque Country	58	2.7	124	2.4
Total	**2,145**	**100.0**	**5,206**	**100.0**

Source: CNMC[16]

RENEWABLE ENERGY POLICY

The resurgence of the SHP sector in Spain was due to the Government's support of the producers of renewable energy. This began with the Energy Conservation Law 82/1980 that suggested reducing fossil fuel consumption and encouraging the adoption of renewable energy with mention of hydropower under 5 MW and solar power.[20] It was then added to by the Royal Decree 2366/1994 which included all other forms of renewable energy and changed hydropower to 10 MW as an important energy source that should be developed more.[21] The Electricity Sector Law 54/1997 set a special regulation for sources of renewable energy with an installed capacity below 50 MW and recognized the environmental benefits of these sources by granting financial benefits including premium pricing, so that renewable energy sources can compete with traditional sources of energy.[22]

The Royal Decree 436/2004 of 12 March 2004, as developed upon the Electricity Sector Law, set the legal and economic framework for a Special Regime for the production of electricity from RES in order to consolidate the rules and to give more stability to the system. The Royal Decree 661/2007, published on 25 May 2007, superseded the previous decree and added another regulation to the production system.[11] This decree set a new system aimed at renewable energy plants in order to achieve the targets of the Renewable Energy Plan 2005–2010. This plan established the goal to have 29.4 per cent of electricity generated using renewable sources by 2010, which was achieved with a 33 per cent share of renewable energy in generation in 2010.[5]

The Spanish economic crisis of 2008–2014, alongside the increase of tariffs, has led to the adoption of a series of contentious measures against renewable energy sources, as they were seen as the cause of this increase. The Royal Decree 6/2009 of 30 April 2009 set the quota for the maximum capacity that can be installed annually for all the renewable energy sources within the special regime. A register was created in order to allow plants falling under the special regime to get access to the financial benefits of the Royal Decree 661/2007. In the aforementioned register, renewable energy plants could only be registered if the limit of renewable energy plants has not been exceeded.[11]

At the beginning of 2013, the new Electricity Sector Law (24/2013) was issued. The law foresees the possibility in certain exceptional cases to establish retributive regimes in order to promote the production of renewable energy. The Royal Decree 413/2014 of 6 June 2014 regulates the generation of energy from renewable energy sources, cogeneration and waste.[11]

Royal Decree-Law 23/2020 of 23 June 2020 approves measures in the field of energy and in other areas for economic reactivation. It enables the Government to establish another remuneration framework, alternative to the specific remuneration regime, in order to favour the predictability and stability in the income and financing of the new electrical energy production facilities that are built from renewable energy sources, which is essential to promote the development of new renewable energy projects with the urgency that is necessary to reach the community and international commitments assumed by Spain in this matter. This remuneration framework, called the Renewable Energy Economic Regime, is based on the long-term recognition of a fixed price for energy and is granted through competitive bidding procedures in which the product to be auctioned will be electricity, installed power or a combination of both, and the variable on which it will be offered will be the remuneration price of said energy.[23]

The 2020 targets for the renewable energy sector were defined in the National Renewable Energy Action Plan (NREAP), which follows the European Directive 2009/28/EC: 20.8 per cent share in gross final energy consumption, 17.3 per cent of heat consumption, 39 per cent of electricity demand and 11.3 per cent of energy demand. The first NREAP of 30 June 2010 was replaced by a new NREAP of 20 December 2011.[11]

The Resolution of 25 March 2021 published the Agreement of the Council of Ministers of 16 March 2021, which adopted the final version of the National Integrated Energy and Climate Plan 2021–2030. Its objectives include: a 23 per cent reduction in greenhouse gas emissions compared to 1990; a 42 per cent share of renewable energy sources in the final use of energy; an increase of 39.5 per cent in energy efficiency; and a 74 per cent contribution of renewable energy to total electricity generation.[24] Two months later, Law 7/2021 of 20 May 2021, on climate change and energy transition, was approved.[25]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

There is currently no regulation published concerning the residual flow. A recommendation could be made in the sense that this flow should be variable during the year, to enable a better adjustment to the differences of the natural hydrological regime and to the spawning seasons.

Until 2012, there were two different support options (under the previous promotion scheme as established by Royal Decree 661/2007), a feed-in tariff (FIT) and a market premium with a cap and a floor, on the sum of market price and premium. However, on 27 January 2012 the Spanish Council of Ministers approved a Royal Decree-Law "temporarily" suspending the FIT pre-allocation procedures and removing economic incentives for new power generation capacity involving cogeneration and renewable energy sources. The move was a result of a tariff deficit of roughly EUR 26 billion (USD 30.2 billion) in 2012, which was largely driven by the incentives for renewable energy sources.[11]

The 2014 Royal Decree 413/2014 (RD 413/2014) replaced renewable energy FITs with a return of 7.4 per cent over the lifetime of a plant. It was introduced alongside the Order IET/1045/2014, which specifies various parameters for calculating the return for different types of renewable energy plants.[11]

In the National Integrated Energy and Climate Plan 2021–2030, there is only one single reference to the SHP technology: "During the 2021–2030 decade, approximately 22 GW of renewable electrical power will have exceeded its regulatory useful life. Without a specific plan for the technological renewal of these projects, it is foreseeable that there will be a reduction in the installed capacity of renewable origin, mainly made up of old wind farms and mini-hydropower plants [...]. In order not to lose their energy contribution, it is necessary to contemplate a specific plan for the technological renovation of these facilities".[24]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Although SHP has played an important role in electricity generation in the country, SHP development currently faces several barriers:

- Hydropower projects have to compete with other water uses over the limited resources;
- Some potential hydropower sites have not been studied in detail, thus there is lack of knowledge regarding their actual potential;
- In order to use water for hydropower purposes, licences need to be issued, which is a complex administrative process and requires an environmental

authorization approval. The excessive waiting time to get approvals from regional and local organs slows the development of potential projects;
- Difficulties in renewing the water concession periods of the current hydropower plants mean that there is the risk of some existing hydropower projects being abandoned.[11]

Enablers for SHP development in Spain include:
- A fully liberalized market allows for any company to generate and distribute electricity;
- In order to reach the goal of 100 per cent of electricity sourced with renewable energy by 2050, SHP could help reduce fossil fuel energy generation.

In the mid-term future, a good part of the thousand existing SHP plants in Spain will be at the end of their concession. For this reason, it is necessary to work on the regulation of this concessional end to guarantee the investments that allow the operation of the plants. Administrative simplification or a call for auctions for technological renewal projects are measures that must be considered.[26]

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4.4. Western Europe

Countries: Austria, Belgium, France, Germany, Luxembourg, Netherlands, Switzerland

INTRODUCTION TO THE REGION

The electricity sectors of countries in Western Europe are highly integrated as a consequence of participation in the European Network of Transmission Systems (ENTSO-E). Additionally, all countries in the region with the exception of Switzerland are members of the European Union (EU). This, along with participation in a wide array of other pan-European and international agreements and frameworks on energy, trade and climate-related topics has meant that the legislative frameworks regulating the electricity sector and long-term energy development strategies of the countries in the region likewise adhere to a set of similar goals and standards.

Nevertheless, geographic, climatic, socio-economic and political factors have meant that countries in Western Europe have often adopted different strategies with regard to their national energy mix. While decarbonization of the electricity sector has been a common priority, several countries, including Germany, Belgium and the Netherlands, continue to rely on natural gas for a significant part of their electricity generation, as an alternative to coal- and oil-fired thermal power plants. Other countries in the region, such as Austria, Luxembourg and Switzerland, have prioritized hydropower or other renewable energy sources (RES) as the mainstay of electricity generation. The development and continued exploitation of nuclear power plants is another contentious issue in the region. The Government of Germany has been a regional proponent of denuclearization and the country has significantly scaled down its operational nuclear power capacity. On the other hand, France, Belgium and Switzerland continue to heavily exploit nuclear power for their energy needs. With regards to RES other than hydropower, the region has invested heavily in wind power and solar power capacity, with Germany possessing by far the largest share of the regional installed capacities in both technologies and aiming to source 80 per cent of its electricity generation from RES by 2050.

Hydropower is a major source of electricity generation for all countries in the region with the exception of Belgium and the Netherlands, where hydropower development is constrained by the flat topography. In Germany, hydropower is mainly concentrated in the mountainous parts of the country, with the states of Bavaria and Baden-Württemburg accounting for over 80 per cent of the country's annual hydropower generation. In France, hydropower is a key secondary energy source, while in Switzerland, Luxembourg and Austria, hydropower is the leading source of electricity generation.

An overview of the electricity sectors of the countries in the region is provided in Table 1.

Table 1. **Overview of Western Europe**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Austria	9	100	100	26,153	72,866	14,640	45,380
Belgium	12	100	100	24,343	81,200	175	N/A
France	67	100	100	136,211	500,000	25,732	65,100
Germany	83	100	100	229,000	489,000	4,856	18,300
Luxembourg	1	100	100	522	2,230	35	1,094
Netherlands	17	100	100	39,132	117,940	38	90
Switzerland	8	100	100	22,063	70,900	15,544	40,700
Total	-	-	-	**477,424**	-	**61,020**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in most countries of Western Europe with the exception of Germany adheres to that established by the EU, which defines SHP as hydropower plants with an installed capacity of up to 10 MW. Germany has not adopted an official definition of SHP as the Government recognizes the lack of international consensus on the definition, but the up to 1 MW definition is used in the country on an unofficial basis.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in Western Europe (MW)**

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (≤10 MW)*	*Potential capacity (≤10 MW)*
Austria	Up to 10 MW	1,521.6	1,780.0	1,521.6	1,780.0
Belgium	Up to 10 MW	76.0	103.4	76.0	103.4
France	Up to 10 MW	2,200.0	2,615.0	2,200.0	2,615.0
Germany	N/A	N/A	N/A	1,674.0	1,830.0
Luxembourg	Up to 10 MW	25.0	44.0	25.3	44.0
Netherlands	Up to 10 MW	13.0	N/A	13.0	13.0*
Switzerland	Up to 10 MW	1,000.0	1,500.0	1,000.0	1,500.0
Total	-	-	-	**6,509.9**	**7,885.4**

Source: *WSHPDR 2022*[1]

Note: *Based on installed capacity.

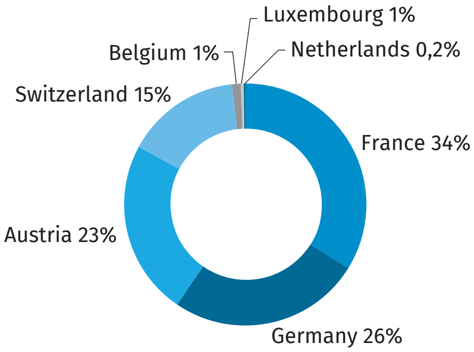
The total installed capacity of SHP of up to 10 MW in Western Europe is 6,509.9 MW, while estimated potential capacity is 7,885.4 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has remained largely the same, decreasing by less than 1 per cent as a result of changes in reporting standards with regard to SHP data in Germany and Luxembourg. Meanwhile, potential capacity has increased slightly by approximately 3 per cent, due to a reassessment of the SHP potential of Switzerland.

Overall, the SHP sector in Western Europe is one of the most mature in the world. Nearly 83 per cent of the potential capacity for SHP of up to 10 MW in the region has already been developed. Consequently, little new SHP development is taking place, as the expansion of RES capacities in the region in recent years has focused on technologies other than SHP. Additionally, as has occurred elsewhere in the world and particularly in Europe, SHP has come under increasing scrutiny from environmental groups, which has resulted in a tightening of environmental regulations and requirements for SHP projects. A significant share of recent activity in the SHP sector has focused on refurbishing or rebuilding existing plants to meet new environmental regulations, including the installation of fish passes and modifications for ensuring reserved flow thresholds. Due to increasingly limited opportunities within the region, many SHP developers from the countries of Western Europe have been looking to expand their range of activity to projects in other parts of the world, particularly in South and Central America and Africa.

Nonetheless, some expansion of SHP capacities has taken place in recent years, particularly in Switzerland. It must also be noted that probable new construction in the SHP sector of the countries of Western Europe is likely higher than publicly available data indicates due to the specificities of data collection practices and legislation in the SHP sectors of several counties including Germany, France and Austria that make it difficult to acquire a comprehensive list of all ongoing and completed projects.

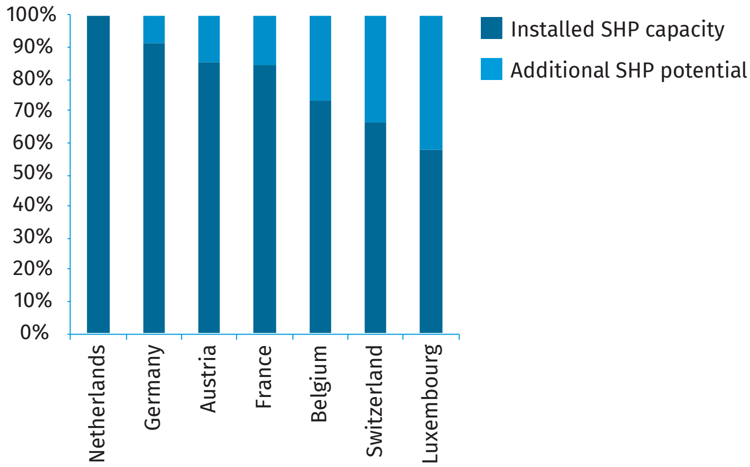
The national share of regional installed SHP capacity by country is displayed in Figure 1, while the share of total national SHP potential utilized by the countries in the region is displayed in Figure 2.

Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in Western Europe (%)**



Source: *WSHPDR 2022*[1]

Figure 2. **Utilized Small Hydropower Potential up to 10 MW by Country in Western Europe (%)**



Source: *WSHPDR 2022*[1]

The installed capacity of **Austria** for SHP of up to 10 MW was estimated at 1,521.6 MW at the end of 2017, provided by 3,307 SHP plants. The potential capacity is estimated at 1,780 MW, indicating that 85 per cent has been developed. The most current data on SHP capacity in Austria are difficult to acquire due to the decentralized and fragmentary nature of reporting on the SHP sector in the country. However, the overall number of registered SHP plants has increased in recent years even as total installed capacity has decreased slightly, due to changes in reporting standards by the relevant national authorities. Over 100 SHP projects were in various stages of planning as of 2021, with many suspended ones due to various obstacles.
Belgium has an installed capacity of 76 MW for SHP of up to 10 MW, which accounts for 43 per cent of the country's total hydropower capacity. Potential SHP capacity is estimated at 103.4 MW, indicating that nearly 74 per cent has been developed. Information on existing SHP plants in the country is incomplete and recent increases in installed capacities most likely re-

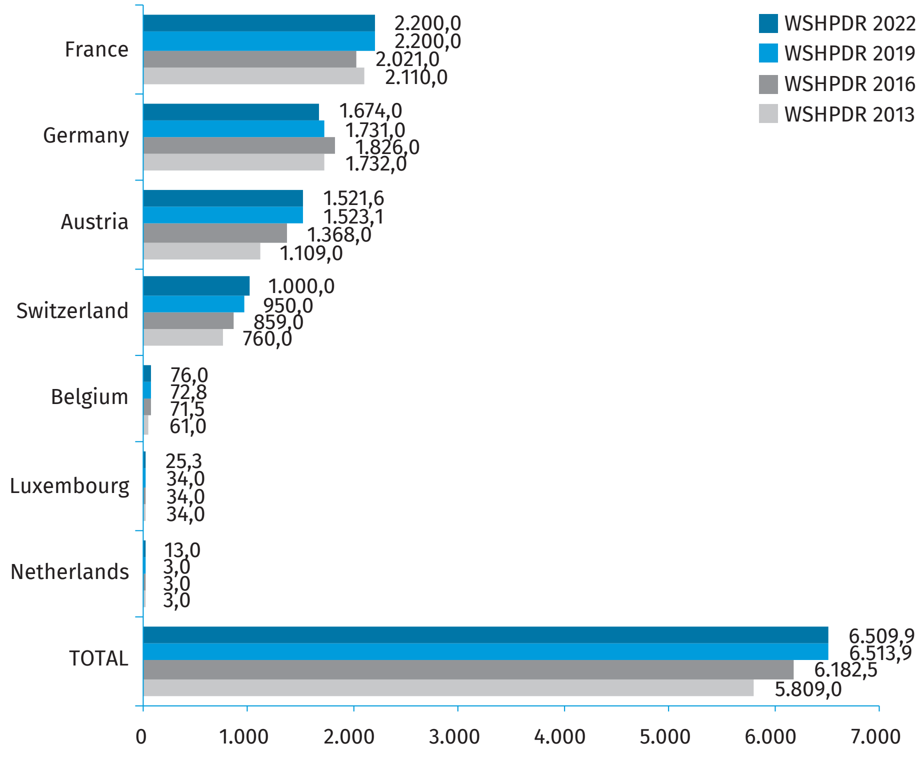
flect the inclusion of previously-unreported SHP capacities in official statistics rather than any new development. Confirmed activity in the sector includes one existing SHP plant undergoing rehabilitation as of 2022.

The total installed capacity of **France** for SHP of up to 10 MW is estimated at 2,200 MW, provided by approximately 2,270 SHP plants. However, comprehensive data on existing SHP plants are difficult to acquire due to legislation specifically limiting the public disclosure of SHP plants with an installed capacity under 0.035 MW. Potential capacity for SHP of up to 10 MW is estimated at 2,615 MW, indicating that 84 per cent has been developed. While the overall estimate of total installed capacity has not changed in the last few years, a large number of new SHP projects were commissioned between 2019 and 2020, with capacities ranging between 0.07 MW and 5.50 MW. Planned projects include the refurbishment of one 2.7 MW SHP plant.

The total reported installed capacity of SHP of up to 10 MW in **Germany** was 1,674 MW in 2020, representing a significant decrease from previous years. However, this figure is the result of changes in reporting standards and likely underrepresents the actual installed SHP capacity of the country. Potential SHP capacity is estimated at 1,830 MW. On the basis of the reported installed capacity data, this suggests that over 91 per cent of the potential has been developed, although data from previous years suggest a figure closer to 100 per cent. There has been no new SHP construction reported in the country in the last decade, as the country's SHP potential is considered to be almost fully developed.

Luxembourg has an installed capacity of 25.3 MW for SHP of up to 10 MW while potential capacity is estimated at 44 MW, indicating that nearly 57 per cent has been developed. The reported SHP capacity of the country decreased due to the exclusion of one previously-included plant with an installed capacity of 13 MW. One additional plant is still reported as part of the installed capacity total, but has functionally been out of operation since 2021 due to heavy flood damage. There has been no significant activity in the SHP sector of Luxembourg in recent years and no new projects are planned.

Figure 3. **Change in Installed Capacity of Small Hydropower up to 10 MW from *WSHPDR 2013* to *WSHPDR 2022* by Country in Western Europe (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

The installed capacity of SHP of up to 10 MW in the **Netherlands** is 13 MW, which is believed to account for the country's entire SHP potential, although a detailed assessment of SHP potential in the country is not available. Reported installed capacity has increased due to the inclusion of a 10 MW hydropower plant not previously recognized as an SHP plant, rather than any new development. In addition to traditional SHP, there is some potential in the Netherlands for tidal SHP applications and several such projects have been installed in 2008 and 2015.

Switzerland has approximately 1,400 SHP plants of up to 10 MW with an estimated total installed capacity of 1,000 MW. SHP potential in the country is estimated at 1,500 MW, suggesting that 66 per cent has been developed. Over the last few years, the country's SHP capacity has increased by approximately 50 MW, with many new plants commissioned between 2018 and 2020. Development is actively ongoing and several additional projects were under construction as of 2021.

Changes in the installed SHP capacities of the countries in the region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Climate Change and Small Hydropower

The changes in the runoff pattern from Alpine rivers due to increased snow and glacial melt induced by climate change in the next decades may be advantageous for SHP in the near term. However, natural hazards, such as floods, glacial lake outburst floods (GLOFs) and landslides, are likely to increase and hamper SHP plant operation and development. Additionally, precipitation in the region is expected to decrease. Without seasonal storage capacity, the downtimes due to extended droughts may halt electricity generation if adaptation measures are not taken. For example, France expects periods of extreme drought due to an increase in evaporation of between 30 and 50 per cent by the end of the century. On the contrary, SHP plants in Belgium and Germany might benefit from increased precipitation in winter and spring and more evenly spread precipitation in summer, respectively. Austria shows a tendency towards decreased annual production overall.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Barriers to SHP development in **Austria** include increasingly strict environmental standards, limited subsidies, bureaucratic barriers and community resistance to SHP projects in direct proximity, despite a generally positive view of SHP. While several support schemes including feed-in tariffs (FITs) have been increasingly restricted to smaller SHP plants (below 2 MW), other forms of support available to SHP in the country include a market premium system, investment support and mixed technology tenders. The SHP sector in the country is well-established and promoted by several lobbying organizations, and RES strategic development plans issued by the Government include targets for the realization of the country's remaining undeveloped SHP potential.

In **Belgium**, SHP development is hampered by the lack of detailed data on potential sites and stringent environmental requirements, causing some local SHP developers to redirect their efforts to projects in other countries. Potential enablers of SHP development include the maturity of the SHP sector, incentives in the form of tradeable green certificates and possible benefits from future increases in runoff.

The main barriers to SHP development in **France** are the financial costs of increasingly restrictive environmental regulations, insufficient incentives to offset these costs, as well as blanket bans on SHP construction on certain watercourses. However, the Government of France has recognized the value of hydropower in general for the country's electricity sector in public pronouncements and detailed studies, particularly with regard to ensuring system flexibility. This is likely to ensure an ongoing active role for the country's SHP sector.

The key barrier to SHP development in **Germany** are the very strict licensing requirements related to environmental standards for both new and existing plants. At the same time, the SHP sector in the country benefits from several enabling factors including a high electricity price, guaranteed funding periods, as well as a carbon tax introduced in 2021, which is expected to make SHP significantly more attractive in the coming years.

The main barriers to the development of SHP in **Luxembourg** are the country's low remaining undeveloped SHP potential and the general lack of demand for additional generating capacities. Additionally, data on SHP sites are lacking and the country has prioritized solar power and wind power in meeting its RES targets. However, support for SHP is available in the form of FITs, market premiums and investment subsidies. One prospective direction for further SHP development in the country are projects on existing non-powered hydraulic infrastructure.

SHP development in the **Netherlands** is limited by the country's flat topography and faces resistance from local water communities as well as from competing water users such as fishermen. However, potential exists in the repurposing of old water mills for power generation, as well as in the development of tidal SHP.

There are some obstacles to the development of SHP in **Switzerland**, including conflicts over water use rights, difficulties with providing electricity transmission and access to greenfield sites, competition from other RES, tightening of requirements necessary for enrolment in support schemes and excessive documentation during the approval process. Overall, however, the prospects for future SHP development in the country are positive, as the SHP sector in the country is mature and abundant undeveloped potential remains available. Most importantly, SHP plays a key role in the country's energy strategy and benefits from multiple forms of support including FITs, investment grants and support for innovative research in the SHP sector. Despite some resistance to greenfield SHP development, SHP projects on existing infrastructure enjoy a high level of social support.

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Austria

Thomas Buchsbaum-Regner, Kleinwasserkraft Österreich

KEY FACTS

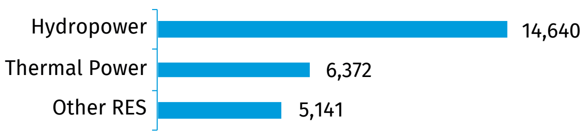
Population	8,926,290 (2020)[1]
Area	83,878 km^2 [2]
Topography	Austria is mountainous in the south and west (the Alps), while along the eastern and northern borders it is mostly flat or gently sloping. Alpine regions cover 67 per cent (appr. 56,200 km^2) of the total land area. The highest point is Grossglockner at 3,798 metres.[3]
Climate	Austria has a temperate continental climate. There are three climatic regions in the country. The eastern region is characterized by a Pannonian climate with continental influence, low precipitation, hot summers and moderately cold winters. The Alpine region has an Alpine climate with high precipitation (with the exception of the inner Alpine valley regions such as the upper Inntal), short summers and long winters. The remainder of the country has a transient climate influenced by the Atlantic in the west and a continental influence in the south-east. Winters in Austria, between December and January, are cloudy and cold with frequent rain and some snow in the lowlands and snow in the mountains. Winter temperatures average between -7 °C and -1 °C. Summers, between June and August, are moderate with occasional showers. Temperatures in July average between 18 °C and 24 °C.[3,4]
Climate Change	Average temperatures in Austria are expected to continue to rise throughout the 21st century. Hot, drier summers will increase in frequency, while the number of days per year with a temperature of over 30 °C will double. Winters are expected to become less cold, with a decrease in the number of days with snow cover. Observed climate change trends in the Alpine region, including increasing intensity and frequency of precipitation, hail and thunderstorms, but also more periods of drought, stronger flood events and glacier retreat, are expected to continue.[5]
Rain Pattern	Rainfall ranges from more than 1,020 mm annually in the western mountains to less than 660 mm in the driest region, near Vienna.[3]
Hydrology	Austria is situated in three transboundary river basins: the Danube, Rhine and Elbe basins. Approximately 96 per cent of the territory of the country belongs to the Danube River basin, which has an average flow of 1,955 m^3/s at the border with Slovakia. Approximately 3 per cent of the territory is part of the Rhine River basin and 1.1 per cent belongs to the Elbe River basin. There are 7,339 rivers and 62 lakes in the country.[3]

ELECTRICITY SECTOR OVERVIEW

The total installed electricity capacity in Austria was 26,153 MW as of 2020. Hydropower, including pumped-storage facilities, provided 14,640 MW (56 per cent) of this total, thermal power provided 6,372 MW (24 per cent). Other renewable energy sources (RES), including wind power, solar power and geothermal power, provided 5,141 MW (20 per cent) (Figure 1). The thermal power capacity in the country has been on a continuous decline since 2015 due to the phase-out of coal power plants, while the capacity of non-hydropower RES has increased dramatically over the last two decades.[6]

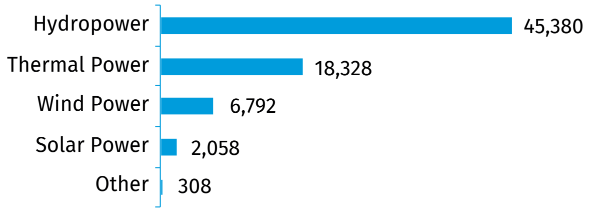
Total electricity generation in Austria reached 72,866 GWh in 2020, with hydropower contributing 45,380 GWh (approximately 62 per cent) of this total, thermal power including both fossil fuels and biofuels contributing 18,328 GWh (25 per cent), wind power contributing 6,792 GWh (9 per cent), solar power contributing 2,058 GWh (3 per cent) and other sources contributing 308 GWh (less than 1 per cent) (Figure 2). The total share of RES (including hydropower and excluding biofuels) in electricity generation was approximately 74 per cent in 2020. Imports of electricity in 2020 amounted to 24,523 GWh while exports amounted to 22,327 GWh.[6]

Figure 1. **Installed Electricity Capacity by Source in Austria in 2020 (MW)**



Source: E-Control[6]

Figure 2. **Annual Electricity Generation by Source in Austria in 2020 (GWh)**



Source: E-Control[6]

The electrification rate in Austria is 100 per cent, with 100 per cent of all electricity consumers being connected to the national grid with the exception of some remote mountain lodges.[7]

Following the Austrian Electricity Industry Organisation Act (EIWOG) adopted in 2000, the Austrian electricity market became fully liberalized by adopting an unbundled market structure with E-Control operating as the state-owned independent regulatory authority. Verbund is the largest electricity provider, covering approximately 40 per cent of the country's electricity demand, with almost 90 per cent of its generation coming from hydropower plants.[8,9] The company also has purchase rights for electricity generated from 20 hydropower plants owned by several other companies. Verbund is listed on the Vienna Stock Exchange as well as the Austrian Traded Index (ATX) with the Government of Austria as the majority shareholder with 51 per cent of the shares.[9] Other significant hydropower producers include Energie AG Oberösterreich, Energie Steiermark, EVN Group, KELAG, Salzburg AG, TIWAG-Tiroler Wasserkraft AG, Vorarlberger Kraftwerke AG and others.

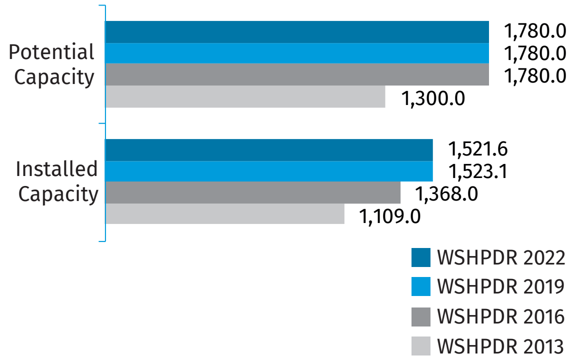
Electricity is traded without intermediaries on the Over-the-Counter (OTC) market or on an energy exchange such as the European Energy Exchange (EEX) or the Energy Exchange Austria (EXAA). The EXAA is a public limited company owned by the Vienna Stock Exchange as well as a number of different companies from the Austrian energy sector that operates a day-ahead electricity spot market. The Austrian Power Grid (APG), a 100 per cent subsidiary of Verbund AG, operates the transmission grid, which is part of the trans-European transmission grid.[7]

The price of electricity for consumers in Austria is based on three components: the amount charged by the supplier, which is set by individual suppliers; a network charge paid to the system operator, which is set by E-Control and based on the grid connection of individual consumers; and taxes and surcharges levied by the Government, including value-added tax (VAT). In 2020, the average gross electricity price, including energy taxes and VAT, was 0.208 EUR/kWh (0.230 USD/kWh) for households and 0.104 EUR/kWh (0.110 USD/kWh) for industrial users.[10]

SMALL HYDROPOWER SECTOR OVERVIEW

Regulated by ÖNORM (Austrian Standards), small hydropower (SHP) is defined in Austria as hydropower plants with a maximum capacity of 10 MW.[11] As of December 2017, Austria had an estimated total installed SHP capacity of 1,521.6 MW from 3,307 plants.[12] Potential SHP capacity has been estimated at 1,780 MW, and included in capacity targets established by the Government. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, installed capacity of SHP in Austria has decreased by a small fraction (less than 1 per cent) even as the number of registered SHP plants has increased, likely due to changes in reporting standards by E-Control. Potential capacity has remained the same due to lack of new estimates (Figure 3).[7,13]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Austria (MW)**



Source: *WSHPDR 2019*,[7] E-Control,[12] *WSHPDR 2013*,[14] *WSHPDR 2016*[15]

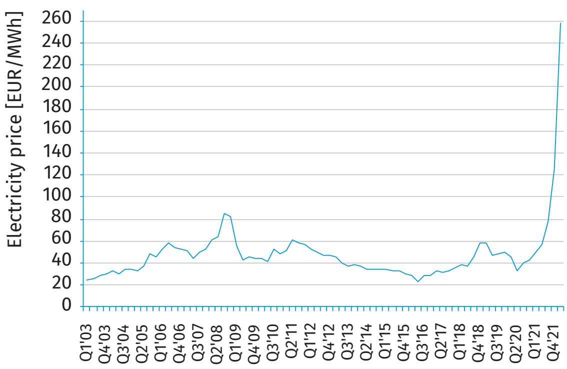
The 3,307 SHP plants identified above were those certified as Green Power Plants by the authorities of Austria at the time, although this number did not include all existing SHP plants in the country.[12] The statistical evaluation of certified Green Power Plants was discontinued in 2018, due to a change in national regulations. The new method of reporting installed capacity and generated electricity established by E-Control is now based on reporting plants issued Guarantee of Origin Certificates (GoO).[16] As of 2020, there were 2,895 SHP plants in the GoO database, with a total installed capacity of 1,374 MW declining from the 1,413 MW reported in 2019.[17] Electricity generated by hydropower plants up to 10 MW, including both run-of-river and pumped-storage plants, amounted to 6,564 GWh in 2020.[6]

The actual total number and installed capacity of SHP plants in Austria is higher than the totals included in the GoO database. Additionally, generation totals for SHP do not reflect self-consumption by the plant operators, which in many cases include industrial facilities such as sawmills. Self-consumption is estimated at approximately 10 per cent of a plant's gross electricity production. However, even accounting for the under-reporting of SHP installed capacity and generation, SHP targets established in 2013 by the Austrian Energy Strategy 2020 of 1,780 MW of installed capacity and an annual generation of 8,000 GWh have likely remained unmet as of the beginning of 2022.[7,18]

New SHP targets have been set by the Renewable Expansion Law of 2021, which envisions an additional 5 TWh of annual electricity generation by 2030 with approximately 2–3 TWh to be accounted for by SHP.[19] Recent studies in three of the nine federal states of Austria have demonstrated that there is still untapped SHP potential in the country, while another 2018 study estimated unused hydropower potential at 11,000 GWh/year.[20,21,22,23]

Approximately 85 per cent of the total electricity produced by SHP plants in Austria receives a market price. In most cases, the plant operator sells directly to a trader in the private sector. In very few cases, the electricity is traded at the Energy Exchange Austria (EXAA) or the European Energy Exchange (EEX) platform in Leipzig, Germany. Since the separation of the Austrian and German electricity markets on 1 October 2018, the obtained price has been strongly linked to the Phelix-AT Baseload Quarter Future derivatives, which are traded at the EXAA. A market-based purchase price, formerly determined on the EEX Phelix Base Quarter Future, is now based on Phelix-AT and settled according to the Austrian Green Electricity Act (ÖSG), last amended in 2017. This price is determined quarterly by E-Control (Figure 4).[7,24]

Figure 4. **Quarterly Electricity Market Prices in Austria 2003-2022 (EUR/MWh)**



Source: E-Control[25]

Before 2003, the federal states of Austria had individual tariff regulations. With the passage of the Green Electricity Act in 2002, a new countrywide tariff system was introduced, with the new tariffs being dependent on the amount of electricity fed into the public grid.[26] SHP plants eligible for incentives under the new system now included two different categories of plants: new SHP plants or SHP plants undergoing refurbishment to increase the mean annual production or capacity by more than 50 per cent, and SHP plants undergoing refurbishment to increase the mean annual production or capacity by more than 15 per cent. New plants and those which were refurbished between 2003 and 2005 with a more than 50 per cent increase in annual production or installed capacity received feed-in tariffs (FITs) for 15 years. Conversely, plants that were refurbished during those years with a more than 15 per cent increase, as well as all plants refurbished thereafter, received FITs for 13 years.[26] After the Green Electricity Act was amended in 2012, new SHP plants (or those undergoing refurbishment that increased the mean annual production or capacity by more than 15 per cent) with a capacity below 2 MW could choose between FITs or an investment support incentive scheme, while SHP plants above 2 MW were only eligible for the investment support option.[27] FITs for SHP plants current as of 2021 are displayed in Table 1.

Table 1. **Small Hydropower Feed-in Tariffs in Austria in 2019**

Delivered electricity	*Feed-in tariffs in EUR/kWh (USD/kWh)*	
	Refurbishment > 15%	*New SHP or refurbishment > 50%*
< 500 MWh	0.0851 (0.1053)	0.1020 (0.1262)
Next 500 MWh	0.0676 (0.0837)	0.0836 (0.1035)
Next 1,500 MWh	0.0577 (0.0714)	0.0725 (0.0897)
Next 2,500 MWh	0.0355 (0.0439)	0.0442 (0.0547)
Next 2,500 MWh	0.0328 (0.0406)	0.0405 (0.0501)
7,500 MWh	0.0251 (0.0311)	0.0320 (0.0396)
For power buoys < 500 MWh		0.1287 (0.1593)
For power buoys > 500 MWh		0.1190 (0.1473)

Source: Source: BMWFW[28]

The Renewable Expansion Law (EAG) adopted in 2021 replaced FITs with market premiums for newly commissioned plants, retained the investment support system and added a third incentive option in the form of mixed-technology tenders. An updated investment support scheme was in the process of being adopted by the Government of Austria as of 2022.

RENEWABLE ENERGY POLICY

The key policy document outlining the renewable energy targets of Austria is the Austrian Climate and Energy Strategy (#mission2030), adopted in 2018. Targets include reducing the country's greenhouse gas emissions by 36 per cent by 2030 relative to the 2005 levels, to be achieved by increasing the share of RES in total energy demand to 45–50 per cent. By 2030, 100 per cent of electricity produced in Austria should come from renewable sources, while the transport sector and heating sectors should also be fully RES-based by 2050. SHP plants play an important role in the #mission2030 strategy, which aims to decentralize electricity generation in order to ease the strain on the electric grid and to gain more grid stability.[29]

The Regulation (EU) 2018/1999 binds Austria to achieving CO2-neutrality by 2050. In 2020, the new Government of Austria set a significantly more ambitious goal, aiming for climate neutrality by 2040.[30]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The key piece of legislation adopted in pursuit of renewable energy targets is the Austrian Renewable Expansion Law 2021 (EAG). The law entered into force on 7 July 2021, with amendments passed on 20 January 2022. Under this law, subsidies for SHP plants constructed on protected stretches of rivers were mostly eliminated and are now applicable only under certain conditions. Furthermore, refurbished or repowered plants of up to 1 MW in installed capacity must now demonstrate a 5 per cent increase in performance or regular working capacity rather than 15 per cent as indicated by the tariff system established in 2003. For plants above 1 MW, this threshold is further reduced to 3 per cent. In addition, performance losses due to environmental protection measures are considered and excluded from the performance increase threshold necessary to receive incentives. The bottleneck performance or regular working capacity must not be lower than the values achieved before the refurbishment.[31]

Types of subsidies available for SHP plants include:

- Investment subsidies, amounting to a maximum of 30 per cent of the investment amount, are to be granted in the course of funding calls, ending the efficient first come-first serve principle. The investment subsidy is an option for the construction and revitalization of an SHP plant up to 2 MW.
- The market premium system, newly established by the EAG, involves a flexible premium to be paid on top of the mean market price of each month. The premium will be calculated as the difference between the average production cost for each renewable technology and the electricity market price of each month.
- Mixed-technology tenders were introduced in the EAG amendments from 20 January 2022, establishing a bidding process for contracting an additional 20 MW of RES capacity per year (wind power and SHP).[31]

In addition to the EAG, earlier legislation plays a major role in regulating SHP in Austria. The Water Rights Act 1959 (WRG) regulates all forms of water use, defining whether a certain water use must be licensed and the conditions and legal requirements for issuing a water use licence. The European Union (EU) Water Framework Directive was implemented in the Water Rights Act in 2003. The Act sets clear targets concerning the protection of surface water bodies and of groundwater.[32]

The National Water Management Plan (NGP), based on the WRG, aims to fulfil the requirements of the EU Water Framework Directive and specifies the means of achieving the established targets for water resources.[33]

Finally, the Environmental Impact Assessment Act (UVP-G 2000) establishes rules and regulations for carrying out environmental impact assessments (EIAs), in line with integrated environmental management principles. The EIA procedure is applied to SHP plants above 2 MW in power plant chains, defined as a series of two or more hydropower plants with an installed capacity of at least 2 MW each and without a sufficient minimum distance between the weir systems in the fish habitat.[34,35]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

As a result of climate change, hydropower generation in Austria is expected to decrease in the summer and increase in the winter. Long-term forecasts show an overall tendency towards decreasing annual production, estimated at between ±5 per cent and -15 per cent by the end of the 21st century.[5]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Barriers for SHP development in Austria have been increasing in recent years, particularly for plants with capacity below 100 kW. Major barriers include the following:

- Limited subsidies leading to sustained stop-and-go cycles in construction activities. As of 2021, more than 100 SHP projects were stuck in the planning process. Dozens more were waiting for the needed decrees determining the detailed regulations for subsidies in order to start construction works;
- Increasing costs of construction;
- Administrative bureaucracy, with excessive requirements for surveys to be completed during the planning process that are of limited relevance to the project itself and raise costs considerably;
- Increasing environmental requirements issued by the Government, including fish passes and reserved flow thresholds;
- Resistance to development works by local communities due to a "not-in-my-backyard" mentality, despite an overall positive perception of SHP.

Factors enabling SHP development in Austria include the following:

- Considerable local technical and economic capacity for SHP development, with dozens of local hydropower companies involved in SHP innovation and development. The SHP sector in Austria has a strong focus on export markets and implementation of environmentally-friendly solutions;
- SHP development is promoted by lobbying groups, including Renewable Energy Austria and Small Hydropower Austria;
- Untapped SHP potential identified by several studies and accounted for in government strategic development plans for RES;
- Several support schemes available for SHP plants, including FITs and investment subsidies.

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Belgium

Tamsyn Lonsdale-Smith, International Center on Small Hydro Power (ICSHP)

KEY FACTS

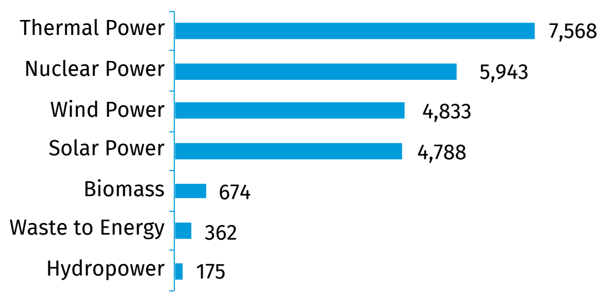
Population	11,521,238 (2021)[1]
Area	30,688 km[2] [2]
Topography	The country is made up of three main geographic zones. The lower region of Belgium is situated around the coast, generally below 15 metres in altitude. Middle Belgium, with altitudes between 60 metres and 180 metres, is a central plain with scattered rivers and streams. The Ardennes, with altitudes ranging from approximately 200 metres to over 500 metres, are home to the highest peak in Belgium — the Signal de Botrange at 694 metres above sea level, which is located in the Hautes Fagnes region near the border with Germany.[2,3]
Climate	The climate in Belgium is temperate oceanic, with mild temperatures and strong winds in the western regions. The mean annual temperature is 10.7 °C, with average maximum temperatures ranging from 5.9 °C in January to 23.9 °C in June (1991-2020). Average minimum temperatures range from 0.4 °C in February to 13.5 °C in July.[4]
Climate Change	Climate change has already been observed in the country, with an average increase of 0.4 °C per decade. Rainfall accumulation has increased by 15 per cent during spring and winter months since 1833, while annual rainfall has increased on average by 7 per cent. Under the RCP 8.5 worst-case emissions scenario, temperatures are expected to rise by 12.7-16.3 °C by the end of the century. In contrast, under the RCP 2.6 scenario, temperatures are predicted to increase by 10.4-12.2 °C.[4]
Rain Pattern	Mean annual precipitation in the country is 885.5 mm (1991–2020). The least rainy month is April, with an average of 50.6 mm, while the month with the heaviest rainfall is December, averaging 92.6 mm (1991–2020). The Wallonia region has a higher monthly precipitation, averaging 84.0 mm, with rain scattered throughout the year. Meanwhile, the highly elevated Ardennes region can accumulate up to 1,400 mm of precipitation per year.[3,4]
Hydrology	There are two major river systems in the country originating from France and continuing eastwards towards the Netherlands: the Schelde (Escaut) and the Meuse (Maas). The highest points of the Ardennes contain peat bogs, offering poor drainage.[5]

ELECTRICITY SECTOR OVERVIEW

In 2021, installed capacity in Belgium reached 24,343 MW, excluding pumped-storage hydropower and approximately 19 MW of unclassified other generation.[6] Thermal power plants made up 31 per cent of total capacity at 7,568 MW, while renewable sources accounted for 44 per cent. Nuclear power accounted for 24 per cent at 5,943 MW. Hydropower made up the least amount of capacity with 175 MW (1 per cent), while wind power and solar power made up 4,833 MW and 4,788 MW respectively (20 per cent each) (Figure 1).

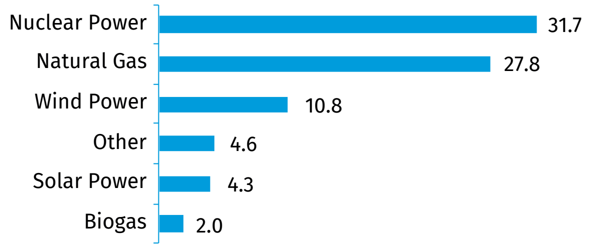
Electricity generation in the country was 81.2 TWh in 2020. This was met primarily by natural gas at 27.8 TWh (34 per cent) and nuclear power at 31.7 TWh (39 per cent).[7] Wind power made up 10.8 TWh of the total generation (Figure 2). Belgium has gone from being a net exporter in 2018 to a net importer of electricity in 2019 and in 2020.[7] Electrification in urban and rural areas is at 100 per cent.

Figure 1. **Installed Electricity Capacity by Source in Belgium in 2021 (MW)**



Source: ENTSO-E[6]

Figure 2. **Annual Electricity Generation by Source in Belgium in 2020 (TWh)**



Source: Elia Group[7]

Note: Hydropower is included in "other" generation under official energy statistics in Belgium.

Belgium is constituted of three main regions: The French-speaking Wallonia region, the Dutch-speaking Flemish region and the capital of Brussels. This segregation has influenced the structure of the electricity system, which is largely governed by the regions separately from the Federal Government. Belgium has a fully liberalized electricity sector, allowing for market competition in both the generation and supply subsectors. The national regulator, the Commission for Electricity and Gas Regulation (CREG), is tasked with regulating access to the networks and approving electricity tariffs. Each region also has its own regulator, including the Flemish Regulator of the Electricity and Gas Market (VREG), Walloon Energy Commission (CWaPE) and Brussels Gas Electricity (BRUGEL). The role of the national regulator includes advising on energy issues to Government authorities, monitoring the energy market, ensuring compliance with legislation, monitoring anticompetitive behaviour, settling disputes and imposing sanctions.[9] The regional regulators are tasked with granting supply licences and green certificates and advising regional authorities on energy-related issues.
The transmission network handles voltages of 30–400 kV with over 8,896 kilometres of lines and underground cables.[8] The network is owned and operated under monopoly by Elia Group, a company that is interconnected on a European level. The Third Energy Package of Belgium enforces the unbundling of the transmission system operator (TSO) from generation and supply activities. However, the Act of 8 January 2012, which was intended to transpose this requirement into national law, has been significantly watered down following a challenge in the Constitutional Court, reducing the expected ambition towards unbundling of these activities.[9] Distribution networks are operated by the regional distribution system operators (DSOs) at below 70 kV voltage levels.[9] In Flanders, the umbrella DSO organization is called Eandis and is composed of 11 smaller DSOs. The overarching DSO in Wallonia is called ORES.

Across all regions, electricity prices have fallen from January 2020 to January 2021 (Table 1) despite an increase in average electricity bills by 66 per cent during the period from 2007 to 2019.[10] Electricity tariffs in Belgium are partially driven by the market and partially regulated. In June 2021, the annual average Wallonian household electricity bill amounted to EUR 994.12 (USD 1,153.08), of which 38 per cent was due to market competition reflected through the unregulated part of the electricity price.[11] Distribution grid charges represented 33 per cent of the price (Table 2).

Table 1. **Electricity Prices in January 2020 and January 2021 by Region in Belgium**

Region	*Electricity price in 2020 (EUR (USD))*	*Electricity price in 2021 (EUR (USD))*	*Decrease (%)*
Flanders	0.275 (0.31)	0.262 (0.30)	4.73
Wallonia	0.277 (0.31)	0.264 (0.30)	4.66
Brussels	0.233 (0.26)	0.220 (0.25)	5.25

Source: Energy Price Belgium[10]

Table 2. **Composition of Annual Average Electricity Tariffs in Wallonia in 2021**

Total electricity price (EUR (USD))	*Federal and regional surcharges (EUR (USD))*	*Green energy tariff (EUR (USD))*	*Transport (EUR (USD))*	*Distribution (EUR (USD))*	*Energy production (EUR (USD))*
994.12 (1,153.08)	23.08 (26.77)	117.92 (136.76)	153.14 (177.61)	326.10 (378.21)	373.89 (433.64)

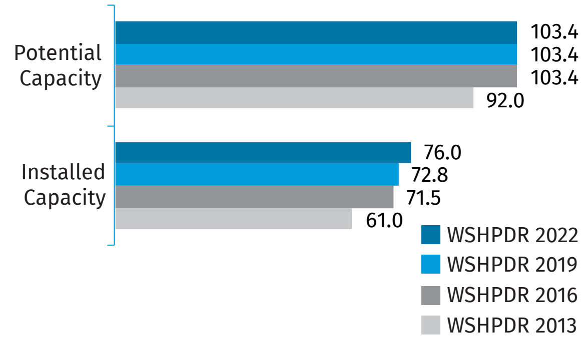
Source: CWaPE[11]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition for small hydropower (SHP) in Belgium is plants up to 10 MW in capacity. The total installed capacity of SHP as of 2019 was 76 MW, with the vast majority of this capacity being situated in the Wallonia region, whereas Flanders was home to approximately 5.6 MW of SHP capacity from 13 power plants.[12,14,15] Information on installed SHP capacity is only known for transmission-connected plants and those that appear in the green certificates database.

The increase in the combined capacity of operational SHP plants since the *World Small Hydropower Development Report (WSHPDR) 2019* (Figure 3) is due to the inclusion into the SHP capacity calculation of two new databases on the allocation of green certificates, which provide lists of hydropower capacities benefiting from this scheme in each region.[14,15] The increase is thus likely due to the inclusion of micro- and pico-hydropower pants in the official statistics, rather than actual growth in the sector. Meanwhile, the economically-feasible potential of SHP in Belgium has stayed the same as in the previous two editions of the *WSHPDR* due to the lack of more recent data. The European Small Hydropower Association has carried out a potential assessment, having identified 83 potential SHP sites in Belgium.[13] Economically feasible annual production from these sites was estimated at 293 GWh. Unfortunately, this source is no longer publicly available and the total capacity of these sites is unknown.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Belgium (MW)**



Source: Energie Commune,[12] VREG,[14] CWaPE,[15] *WSHPDR 2013*,[16] *WSHPDR 2016*,[17] *WSHPDR 2019*[18]

Note: Only data for SHP plants that received green certificates or are TSO-connected are available.

Apart from two large pumped-storage plants, there are two hydropower plants, both located in Wallonia, that surpass 10 MW of installed capacity at a combined installed capacity of approximately 38 MW.[19,20] By deducting the capacity of these two power plants from the regional hydropower installed capacity estimates provided by Energie Commune, it can be determined that approximately 73 MW of SHP capacity is located in the Wallonia region, while the remaining are from plants in Flanders.[12]

Hydropower in Belgium faces constraints originating from competing water uses, in particular from the industrial and large consumer sectors, such as the nuclear sector, which represents a significant demand for water as a cooling agent.[5]

Comprehensive data on hydropower plants are not publicly available and data are only published on solar and wind power plants under a voluntary initiative from the Belgian Federation of Electricity and Gas Enterprises (FEBEG).[21] Table 2 displays a non-comprehensive list of SHP plants in Belgium.

Table 2. **List of Selected Operational Small Hydropower Plants in Belgium**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Hu Ivoz-Ramet	Liege	10.00	EDF Luminus	1954
Ampsin-neuville	Amay	9.90	EDF Luminus	1965
Hu Andenne	Andenne	9.00	Luminus	1980
Hu Grand-Malades	Namur	5.00	Luminus	1988
Heid-de-goreux 2	Aywaille	5.00	Electrabel	1931
Heid-de-goreux 1	Aywaille	4.00	Electrabel	1931
Wtr-0025 Ham	Sluisstraat 24 A, 3945 Ham	2.40	Inter-Energa	2015
Wtr-0026=Olen	Sluizenweg zn, 2250 Olen	2.40	Iveka	2014
La Vierre	Chiny	1.90	Electrabel	n/a
Butgenbach	Butgenbach	1.80	Electrabel	1932
Hu Floriffoux	Namur	0.80	EDF Luminus	1993
Wtr-0001 Wijnegem Waterkracht (gsc rest)	Stokerijstraat zn, 2110 Wijnegem	0.33	Iveka	2009
Wtr-0023 Hydrocatala	Grote Baan 302, 1620 Drogenbos	0.11	Iverlek	2013
Wtr-0007 Lozen Hydro (nai)	Kempenstraat, 3950 Bocholt	0.10	Inter-Energa	2007
Wtr-0006 Bocholt Hydro (nai)	Snellewindstraat, 3950 Bocholt	0.06	Inter-Energa	2007
Wtr-0021 Johnny Thijs	Klein Overlaar 75, 3320 Hoegaarden	0.02	Iverlek	2011
Wtr-0022 Molen van Schoonhoven	Diestsesteenweg 12, 3200 Aarschot	0.01	Iverlek	2012
Wtr-0020 Provinciebestuur Oost-vlaanderen	Rekegemstraat 29, 9630 Zwalm	0.01	Gaselwest	2010
Wtr-0018 Willy Bauwens Waterkracht	Kloosterstraat 92, 9340 Lede	0.01	Imewo	2007
Wtr-0019 Vrienden van de Molen	Molenhoek 14, 9620 Zottegem	0.004	Intergem	2009

Source: Elia Group[22]

Information on potential sites or projects in planning are not publicly available either, nor are they published in a centralized database. However, environmental data on stream flow and height could be a starting point for future studies on SHP potential in Belgium.[23] Table 3 provides details on one SHP project currently undergoing rehabilitation.

Table 3. **Planned Small Hydropower Project in Belgium**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Developer*	*Planned launch year*	*Stage of development*
Bevercé	Robertville Dam, Malmédy	10.0	Reservoir	Tractebel	2022	Rehabilitation

Source: Hydro Review[24]

RENEWABLE ENERGY POLICY

The Act of 29 April 1999 on the organization of the energy market is the primary federal act containing information on generation rules as well as the role of the transmission grid and federal regulator. Each region has its own main piece of legislation detailing electricity sector rules, including available support mechanisms for renewable energy generation. These are the Decree of 8 May 2009 for Flanders, the Decree of 12 April 2001 for the Wallonia region and the Ordinance of 19 July 2001 for the Brussels-Capital region.[9]

Recent policies include the European Union–mandated Integrated National Energy and Climate Plan 2021–2030, which set a target of 17 per cent of gross final energy consumption to be met by renewable sources by 2030.[25] The plan defines several regional scenarios, with the most ambitious scenario for the Wallonia region, indicating that hydropower is to meet 440 GWh of generation by 2030, up from 314 GWh in 2015. No increased hydropower generation is envisioned under the Flemish regional projections. The new long-term strategy document to 2050 has no mention of hydropower, suggesting that renewable energy policy is not favourable towards hydropower development in the medium-to-long term.[26]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

Supply licences are offered by the regional regulators: CWaPE, VREG and BRUGEL. Obtaining a production permit as part of the licensing process is not mandatory for any plants under 25 MW.[9]

COST OF SMALL HYDROPOWER DEVELOPMENT

The cost of SHP projects varies greatly depending on the size of the plant, the model, the developer and other factors. According to a study by the International Renewable Energy Association (IRENA), the installation costs can vary from 1,300 USD/kWh to 8,000 USD/kWh within the European Union.[28] The estimate for Belgium is 20,000 EUR/kW (22,668 USD/kW) in installed capacity for plants of under 1 MW and 3,000 EUR/kW (3,400 USD/kW) for plants above 1 MW.[27] Operational costs are approximately 1–4 per cent of installation costs. The levelized cost of electricity (LCOE) for SHP in Belgium is between 0.15 USD/kWh and 0.18 USD/kWh. This is higher than the EU average LCOE for SHP.[28]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

In Belgium, each region is responsible for the promotion of renewable energy sources within its own territory. A Tradeable Green Certificate (TGC) Mechanism is in place across the regions and in collaboration with the Federal Government. For Brussels and Wallonia, certificates are issued to producers who save a predetermined quantity of CO_2 emissions compared to the average generation facility. Currently, hydropower plants receive, depending on their generation and consumption, between 2.5 and 0.71 green certificates per MWh produced for 20 years.[27] TGCs are allocated by the regulation authorities of each region, each having its own set quota for green certificates that suppliers must abide by. Failure of suppliers to comply could lead to penalties. Installation premiums are also available for renewable energy generators or installers.[9]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change is already taking effect in the country, with precipitation having increased by 7 per cent on average compared to 1833. This could have a positive effect on SHP capacity factors, especially during the spring and winter months when precipitation increases are most prominent. However, without proper design, SHP plants could be at risk of overflow and flooding, especially in the case of small catchment areas.[29]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The following points summarize the main barriers to SHP development that have been identified for Belgium:

- Limited access to data on potential sites for development;
- Environmental limitations imposed on developers, including EU-level environmental restrictions from legislation such as the European Water Framework Directive, and unclear rules regarding environmental constraints;
- Ageing sector with key developers focused on bringing designs to other countries.

The following points summarize the main enablers that have been identified:

- Increased precipitation due to climate change with a positive effect on plant capacity factors;
- Incentive to develop green energy through the TGC mechanism and exoneration from distribution costs;
- Strong baseline of existing operational SHP plants, indicating a mature sector with learned expertise.

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France

Aurélie Dousset and Jean-Marc Levy, France Hydro Électricité; and Tamsyn Lonsdale-Smith, ICSHP

KEY FACTS

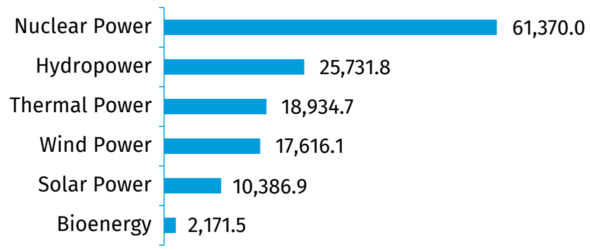
Population	67,063,703 (2020)[1]
Area	549,000 km² [2]
Topography	The topography of France includes mostly flat plains or gently rolling hills in north and west. The remainder is mountainous, particularly the Pyrenees in the south and the Alps in the east. The country's highest point is Mont Blanc at 4,807 metres.[2]
Climate	Three types of climate are found in France: oceanic (west), continental (central, east) and Mediterranean (south). Average temperatures in oceanic Brittany are 6 °C in winter and 16 °C in summer. Paris, which lies in the continental climate, averages a yearly temperature of 11 °C. The southern coastal city of Nice experiences an annual average of 15 °C.[2]
Climate Change	By 2040, France is expected to experience longer periods of drought and low rainfall. At the same time, episodes of intense rainfall will be more frequent in the south of the country. Heat waves will also become more intense by the end of the century. Under an unabated emissions scenario (RCP 8.5), average temperatures would increase by 3.9 °C between 2070 and 2100 compared to the average pre-2005 temperatures. Summer temperatures under the same scenario would increase by 6 °C.[3]
Rain Pattern	Annual precipitation ranges from 680 mm in the central and southern regions to 1,000 mm around Paris and Bordeaux. In the northern coastal and mountainous areas precipitation can reach up to 1,120 mm or more.[2]
Hydrology	Five major rivers create the drainage system of France. The Seine (780 kilometres) flows through the Paris basin and has three tributaries: the Yonne, Marne and Oise Rivers. The Seine drains into the English Channel. The Loire (1,020 kilometres) is the longest river in France and flows through the central region. The Garonne is the shortest of the major rivers in France. It rises in the Pyrenees, across the border with Spain, and empties into the Bay of Biscay at Bordeaux. The Rhone is the largest and most complex of French rivers. Rising in Switzerland, it flows southwards through France for 521 kilometres, emptying into the Mediterranean. Lastly, the Rhine flows along the eastern border for approximately 190 kilometres, fed by Alpine streams.[2]

ELECTRICITY SECTOR OVERVIEW

In 2020, installed capacity in France amounted to a total of 136,211 MW, of which nuclear power made up 61,370 MW, or 45 per cent (Figure 1). The most capacity additions since 2019 were seen in solar and wind power, which is in line with policy objectives for new renewable capacity additions. The only power source to see reductions since 2019 was nuclear, which declined by 2.8 per cent.[3] Renewable energy sources (including large hydropower) made up 55,906 MW in total, or 41 per cent of total installed capacity. Discounting large hydropower, renewable energy made up 32,374.5 MW, or almost 24 per cent.

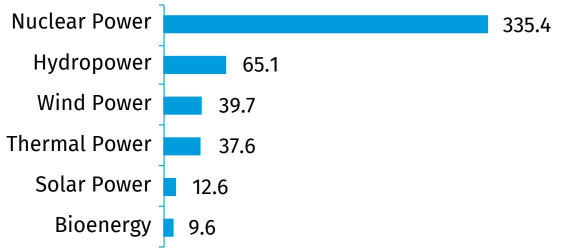
Electricity generation in France is mainly made up by nuclear power. In 2020, it accounted for 335.4 TWh or 67 per cent of the total electricity generation of 500.0 TWh. Other sources of generation include hydropower at 65.1 TWh, wind power at 39.7 TWh, thermal power at 37.6 TWh, while the remaining 22.3 TWh was made up of solar power and bioenergy (Figure 2).[3] Most of the thermal power production was from natural gas, constituting 34.5 TWh or 91.8 per cent in 2020, which indicates a 10 per cent decrease from the 2019 levels of natural gas production. In 2020, electricity production in France declined by 7 per cent compared to 2019 due to the Covid-19 crisis, in response to a reduction in consumption.[4] During 2020, energy consumption in France decreased to 460 TWh from 477 TWh in 2019, which translates into an almost 4 per cent decrease.[3]

Figure 1. **Installed Electricity Capacity by Source in France in 2020 (MW)**



Source: RTE[4]

Figure 2. **Annual Electricity Generation by Source in France in 2020 (TWh)**



Source: RTE[3]

The Ministry of the Ecological Transition is in charge of regulating the energy sector. The electricity grid is owned and operated by the Electricity Transmission Network (Réseau de Transport de l'Électricité, RTE) and ENEDIS. RTE operates the public high-voltage electricity transmission network from production centres to distribution networks, whereas ENEDIS operates the medium- and low-voltage electricity distribution network in 95 per cent of France. The electricity network consists of 106,047 kilometres of power lines. In 2020, more than 250 kilometres of underground power lines were added.[3] The French electricity market is open. However, it remains largely dominated by the formerly state-owned Électricité de France (EDF). The electrification rate of the country is 100 per cent.[5]

According to Article L410-2 of the Commerce Code and Article L337-1 of the Energy Code, electricity tariffs are generally subject to competition, buy may be regulated against the high and low competitive prices, in crisis situations, or under exceptional circumstances.[6,7] Electricity tariffs in France are regulated by the Ministry of Ecological Transition and the Ministry of Economy, Finances and Recovery by means of decree, twice a year in July and January, after consultation with the National Consumer Council. Consumers have the choice between a regulated tariff with their electricity producer or a market-based rate. The prices as of 1 August 2021 during peak and off-peak hours are displayed in Table 1.

Table 1. **Electricity Tariffs in France as of 1 August 2021**

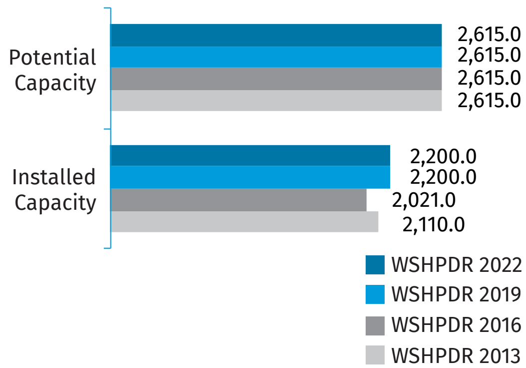
	Residential Rates		*Business Rates*	
Meter Power rating	*Peak EUR/kWh (USD/kWh)*	*Off-peak EUR/kWh (USD/kWh)*	*Head (m)*	*Type of site (new/refurbishment)*
3 kVA	0.1558 (0.18)	0.1558 (0.18)	n/a	n/a
6 kVA	0.1821 (0.21)	0.1360 (0.16)	0.1125 (0.13)	0.785 (0.90)
9 kVA	0.1821 (0.21)	0.1360 (0.16)	0.1125 (0.13)	0.785 (0.90)
12 kVA	0.1821 (0.21)	0.1360 (0.16)	0.1125 (0.13)	0.785 (0.90)
15 kVA	0.1821 (0.21)	0.1360 (0.16)	0.1125 (0.13)	0.785 (0.90)

Source: Kelwatt[8]

SMALL HYDROPOWER OVERVIEW

In France, small hydropower (SHP) is defined as plants having an installed capacity up to 10 MW. The SHP installed capacity is approximately 2,200 MW from approximately 2,270 plants (Table 1).[15] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has remained unchanged (Figure 3). No new feasibility studies have been conducted and the potential capacity also remains at 2,615 MW. The total annual generation from SHP is 6 TWh on average, which is roughly 10 per cent of the total hydropower generation in France.[9,10,11] It should be noted that in France there is no systematic tracing of SHP plants and thus the installed capacity figures presented are indicative rather than exact. Overall, information on SHP is not fully transparent in France. This is exemplified by the fact that any plant of under 36 kW cannot be publicly disclosed under the Public Order of 7 July 2016.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in France (MW)**



Source: *WSHPDR 2013*,[12] *WSHPDR 2016*,[13] *WSHPDR 2019*,[14] France Hydro Electricité[15]

Renewable energy plays an increasingly important role in meeting energy needs in France and hydropower remains the leading source of renewable electricity in the country. The Multi-Year Energy Plan (Programmation Pluriannuelle de l'Energie, or PPE) published in October 2016 sets the goal of increasing hydropower installed capacity from 500 MW to 750 MW by 2023.[16]

The Ministry of Ecological and Solidarity Transition launched the first call for projects for the development of SHP in April 2016 to promote the construction of new green fields and upgrade the equipment of existing dams. The 19 winners of this first call for projects, representing a capacity of 27 MW, were announced in April 2017. To continue this dynamic initiative, the Ministry announced in April 2017 a new call for tenders for 105 MW of new SHP capacity, divided into three application periods of 35 MW. This multi-year call for tenders, which ended in 2021, enabled the addition of 93.6 MW of new capacity over three periods. The PPE published in October 2019 set the goal of increasing hydropower installed capacity to 26.4-26.7 GW by 2028. As a result, the previous call for tenders for 35 MW in Q1 of each year has been renewed until 2024.[8]

A national register of electrical installations, hosted by Open Data Energy Networks réseaux énergies is the most comprehensive database that collates information from many electricity producers on SHP plants in France, both operational (Table 2) and in planning (Table 3).[14]

Table 2. **List of Selected Operational Small Hydropower Plants in France**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Centrale de consolation-maisonnettes	Consolation-Maisonnettes, Doubs	0.54	63	Run-of-river	ENEDIS	2020
Moulin de ratayrens	Le Riols, Tarn	0.42	2	Run-of-river	ENEDIS	2019
Centrale de crevoux	Crévoux, Hautes-Alpes	3.06	283	Run-of-river	ENEDIS	2019
Sh aqua bella	Val-d'Arc, Savoie	2.20	0	Run-of-river	ENEDIS	2019
Sacom - moulin de cartels	Le Bosc, Hérault	0.12	6	Run-of-river	ENEDIS	2019
Confidential	Villard-Bonnot; Isère	5.50		Run-of-river	GAZ ELECTRICITE DE GRENOBLE	2019
Confidential	Velaux; Bouche-du-Rhône	0.23	6	Run-of-river	ENEDIS	2019
Micro-centrale du roc de la peche	Pralognan-la-Vanoise, Savoie	0.16	140	Run-of-river	ENEDIS	2019
Centrale de turbinage du debit reserve	Condat, Cantal	0.16	19	Run-of-river	ENEDIS	2019
Confidential	Saint-Girons, Ariège	0.24	2	Run-of-river	ENEDIS	2019
Moulin de bezon	PloÃ«rmel, Morbihan	0.07	0	Run-of-river	ENEDIS	2019
Centrale d eyguieres	EyguiÃ¨res, Bouches-du-Rhône	1.60	12	Run-of-river	ENEDIS	2019
Barrage de mervent - siaep	Mervent, Vendée	1.74	0	Run-of-river	ENEDIS	2019
Hydro antoigne	Sainte-Jamme-sur-Sarthe, Sarthe	0.43	0	Run-of-river	ENEDIS	2019
Confidential	La Roche-Chalais, Dordogne	0.42	3	Run-of-river	ENEDIS	2019
Microcentrale - commune de jougne	Jougne, Doubs	0.09	9	Run-of-river	ENEDIS	2019
Moulin d arignac	Arignac, Ariège	0.50	30	Run-of-river	ENEDIS	2019
Confidential	Schirmeck	0.48		Run-of-river	SA ELECTRICITE DE STRASBOURG	2019
Spl eau du bassin rennais	Plouasne	2.60	0	Run-of-river	ENEDIS	2019
Le moulin de cezi	Arbois	0.75	2	Run-of-river	ENEDIS	2019

Source: Open Data Réseaux Énergie[17]

Table 3. **List of Selected Planned Small Hydropower Projects in France**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Developer*	*Stage of development*
P.ROLH-CENTRALE HYDRAULIQUE DE PONT-ROLLAND-3	Hillion, Brittany	2.7	22	reservoir	RTE	refurbishment

Source: Open Data Réseaux Énergie[14]

The French water administration drafted an inventory of obstacles on rivers and aims to assess the degree to which these obstacles block the movement of species and sediment. A database was created in May 2012, including more than 60,000 obstacles such as dams, locks, weirs and mills no longer in operation.[18] A protocol called the Information on Ecological Continuity (Informations sur la continuité ecologique, or ICE) has been also created to measure the capacity of obstruction of these obstacles. This project identifies the installations causing the greatest problems and makes it possible to set priorities for corrective action.[19]

RENEWABLE ENERGY POLICY

A regional plan for climate, air and energy (Schema regional du climat de l'air et de l'energie, SRCAE) was jointly developed by the national Government and regional authorities. For 2020 and based on geographical area, this plan defines qualitative and quantitative regional targets for the valorization of renewable energy potential. In practice, this means identifying all sources to produce renewable energy and of energy savings according to socio-economic and environmental criteria and defining, in association with the local stakeholders (regional authorities, companies and citizens), the level of regional contribution in achieving the set national targets. This plan represents a strategic planning tool to guide the activities of local and regional authorities in relation to renewable energy development.[5] For hydropower potential, SRCAE is based on producers' data and compatibility with lists of no-go rivers and restoration of river continuity priorities.

In 2012, the share of energy produced from renewable sources in France amounted to less than 14 per cent and the target for 2020 was set at 23 per cent. Since renewable energy capacity stood at almost 24 per cent in 2020, France has reached the target. In August 2015, the Energy Transition Law was promulgated. This law set the framework for the energy transition towards a greener and cleaner energy, with a new objective of 32 per cent of energy consumption met by renewable resources, and 40 per cent of production, by 2030.

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

One of the major difficulties in the preservation and development of SHP in France lies in the implementation of ecological continuity, directly resulting from the implementation of the European Framework Directive on Water. Given the many blockages in the implementation of the restoration of ecological continuity, a working group has been set up by the National Water Committee (Comité National de l'Eau, CNE). The CNE, created in 1964, is made up of representatives of users, associations, local authorities, representatives of the state, presidents of basin committees and persons competent in the water sector. The working group is consulted on the major orientations of water policy, national water development, distribution projects, major regional developments as well as on draft laws and regulations.

In 2018, the CNE published an action plan for a "policy of restoring the ecological continuity of rivers".[20] A technical note, published on 30 April 2019, detailed the implementation of this plan. In particular, the plan provides for a homogeneous prioritization of actions to restore ecological continuity for the benefit of the good condition of the watercourses and the restoration of biodiversity. This prioritization process has not been fully successful in improving the situation on the ground, and should be reflected in the new Master Plan for Water Development and Management (SDAGES) in preparation as of 2021.[21]

The maximum duration of permits is 75 years for big concessions. For relicensing, the duration is 20 years if there is no particular investment and approximately 30–40 years if there is a significant investment. France has a lot of perpetual old permits for former mills subjected to new environmental restrictions. The Government's priority is to simplify the legislation and some measures, such as a proposed law on Unique Authorization, are under review as of 16 October 2019.[22] The idea is to merge the different authorizations into one category to accelerate the process and relieve the administrative burden for rehabilitation of old SHP plants in particular.

Residual flow regulation exists: 10 per cent of interannual average flow and for modules over 80 m^3/s 5 per cent is allowed.[10] While the minimum (10 or 5 per cent) is set by the law, the adapted minimum ecological flow is set on a case-by-case basis through environmental assessments. The most used method is the micro-habitat method (using EVHA software), but there are also other possible methods adopted when EVHA does not suit the type of river. After 1984, the reserved flow was approximately 10 per cent of the average annual flow. Since 2006, 10 per cent is the minimum and local administrators often ask for more (12–17 per cent), without any justification on improvement or maintenance of the ecological status. In periods of extreme low water levels, the heads of departments (French administrative subdivision) can decide to temporarily lower the residual flow.

A Commitments Agreement for the Development of a Sustainable Hydropower was signed by the minister, representatives of local elected authorities, representatives of power producers, several NGOs and the national committee for professional fresh water fishing in June 2010 to promote hydropower if deemed suitable considering the environmental specifications.[23] This was done in compliance with European aquatic environment restoration requirements. A part of the agreement directly concerns the equipment of existing weirs. The methodology and the suitable conditions for building a power plant onto existing weirs need to be made more detailed. A guidebook Towards the Hydroelectric Plant of the 21st Century for the development of SHP plants with regards to the natural environment is available.[11] It defines standards for the construction of an environmentally sustainable plant. This guide is recognized and disseminated by European national administrations.

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Finally, under the impetus of the European Commission, France enacted a law on energy transition (2015) in compliance with European State Aid Guidelines. A new tariff order was published in December 2016, the H16 contract, which sets out conditions for plants under 1 MW to access a support mechanism. Plants under 500 kW can benefit from feed-in tariffs (FIT) (tariff H16) and plants between 500 kW and 1 MW can benefit from premium FITs (additional remuneration). This new support mechanism is a bonus paid monthly in addition to the sale of electricity on the market. Purchase prices are between 0.11 EUR/kW and 0.13 EUR/kW (0.13–0.16 USD/kW). Finally, a tendering system is implemented for plants above 1 MW. The draft Renewable Purchase Obligations (RPO) contract for power plants between 1 MW and 4.5 MW, HR21, which has been in the pre-distribution phase since 2019, was to be submitted to the European Commission at the end of the 1st quarter of 2021.

France uses RPO mandates to support the development of renewable energy, including SHP. In 2018, 1,940 MW worth of SHP received support in this form.[8]

COST OF SMALL HYDROPOWER

According to a recent report by the CRE, the cost of SHP development in France is between 2,100 and 5,600 EUR/kW (2,547–6,791 USD/kW) for 70 per cent of the new projects, while operational expenditures are between 50 and 180 EUR/kW (61–218 USD/kW).[24] This does not include costs pertaining to replacement of materials.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

According to a recent report by Météo France, under several climate change scenarios, periods of extreme evaporation during summer draughts are expected to increase, which will have implications for all hydraulic resources. The extent of this phenomenon varies depending on the scenario. Under both the RCP 4.5 and RCP 8.5, periods of extreme evaporation will increase by between 30 and 50 per cent by the end of the century. However, under a minimum warming scenario, the effect is less strong, with the possibility of a decrease in duration of these summer droughts.[3]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are multiple barriers to SHP development in France. Some of the main barriers are outlined below:

- The classification of rivers carried out by the Government in 2012 states that no more new works (no hydropower plants among other) can be created on the rivers ranked in List 1, which impacts more than 71 per cent of the hydropower potential. This classification also implies for the owners of hydropower plants located on rivers ranked in List 2 to carry out heavy and expensive installations to ensure the transport of the sediment and fish migration.
- Costs related to the environmental development are becoming increasingly burdensome for producers, representing investments in the range of several times the turnover of a plant.
- There are numerous financial obstacles to SHP development. French producers who cannot or do not wish to invest to benefit from new FIT contracts have to sell their electricity directly on the market. The market price does not take into account specificities of SHP production (i.e., the green value and the decentralized production). The market price level of SHP electricity generation (approximately 40 EUR/MWh (49 USD/MWh) in 2017) does not allow any investment and may push some small units into bankruptcy. The industry has also alerted the authorities about the inflation of the local taxation, which can reach to 10 EUR/MWh (12 USD/MWh), i.e., a quarter of the purchase price of electricity on the market.[25]

The following points summarize the main enablers to SHP development in the country that have been identified:

- In his speech presenting the Multiannual Energy Programme, President E. Macron specifically praised the role and qualities of hydropower as "*a strength of our territories and a strength of our low electricity production, cost and low emission*". The objectives set for hydropower by 2028 are a clear message from the Government who wants to preserve production capacities by strengthening them wherever possible.[26]
- France Hydro Electricité published in December 2020 a study about hydropower and flexibility. Based on the 2020 operation, this study confirms the role played by hydropower in the flexibility of the electrical system according to its three components: the structural variation of the residual demand, coverage of forecast errors of the residual demand between D-1, real time and dynamic (less than half an hour). It then shows the extent of the flexibility needs that will be necessary in the medium and long term, whatever the electricity mix scenario envisaged, and the evolution of the role that hydropower could play.

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Germany

Tobias Dertmann, Hydropower Consultant

KEY FACTS

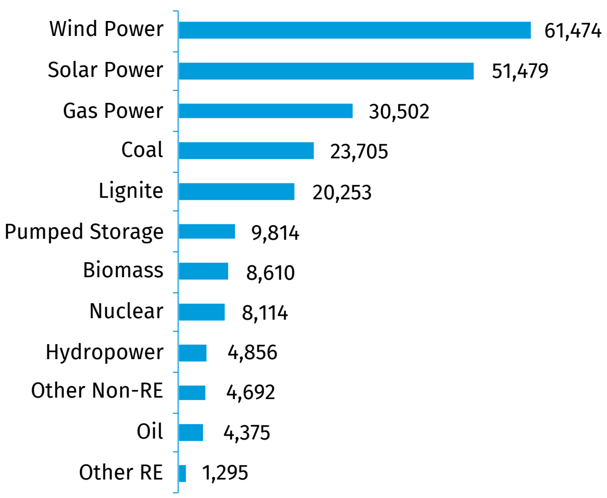
Population	83,157,201 (2020)[1]
Area	357,580 km² [2]
Topography	The northern areas of Germany are characterized by coasts and lowlands, while the centre is mainly covered by forested uplands. Low mountains in the south-west merge with the Bavarian Alps in the south-east, which form the border with Austria and Switzerland, with the highest altitude at the Zugspitze (2,963 metres). The country's lowest point is 3.5 metres below sea level.[3]
Climate	The north-western and coastal areas of Germany are characterized by a maritime-influenced climate with warm summers and mild winters. The climate transitions to a continental one to the south-east, with greater seasonal variations in winter and summer. The Alpine regions exhibit lower temperatures and higher precipitation. Historically, the mean temperature in winter (December-February) has been 0.9 °C and in summer (June-August) 16.3 °C. Extreme temperatures can reach from -10 °C to +35 °C. Occasionally there is warm mountain wind.[3]
Climate Change	The German weather service predicts an increase of up to 30 per cent in winter precipitation, while summers are predicted to be up to 40 per cent warmer due to climate change. Higher amounts of heavy precipitation are to be expected in the entire country.[3]
Rain Pattern	Average annual precipitation is 789 mm. The amount of rainfall decreases across the country from west to east, with markedly higher precipitation in the southern mountainous regions.[4]
Hydrology	Germany is rich in water resources, with 2 per cent of its surface area covered by water, of which 40 per cent are natural lakes. The country is traversed by major European rivers such as the Rhine, Elbe, Saale, Neckar, Weser, Oder and Danube. The main flow direction of rivers is from the southern Alpine region and central mean range mountains to the north (Rhine, Elbe, Weser) and to the east (Danube). The country's largest lake is Lake Constance (Bodensee), which is shared with Austria and Switzerland.[5]

ELECTRICITY SECTOR OVERVIEW

The German power system is the largest in Europe. In 2020, the country's installed electricity generating capacity totalled 229 GW, with renewable energy sources making up approximately 56 per cent (128 GW) (Figure 1).[6] The generating capacity participating in the electricity market totalled 114 GW.[6] The net power production in Germany in 2020 was 489 TWh, of which renewable sources contributed approximately 51 per cent (247 TWh) (Figure 2).[7]

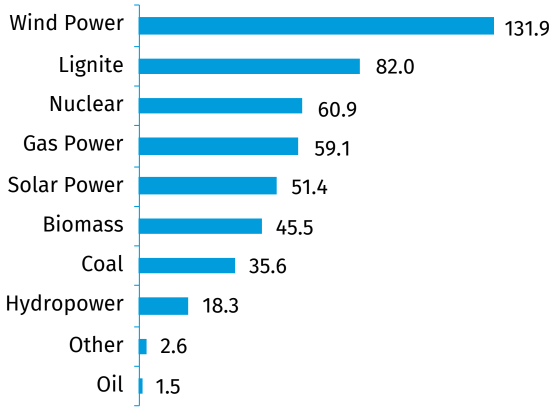
Power generation in the German electricity market is currently dominated by four incumbent power generators that share the market with a small number of regional utilities and hundreds of municipal utilities. With the liberalization of the electricity market in 1998 and dedicated policies focused on ushering in the energy transition (*Energiewende*), several independent power producers have entered the market, especially operating small-scale wind power and solar photovoltaic (PV) plants, reflecting a trend towards increasing decentralized power generation. Following the European Commission legislation mandating a legal unbundling of network businesses in 1996, the four incumbent transmission companies became legally independent from their parent generator companies. Distribution networks are owned and operated by more than 800 regional and local operators. The rate of electrification in Germany is 100 per cent.

Figure 1. **Installed Electricity Capacity by Source in Germany in 2020 (MW)**



Source: Federal Network Agency[6]

Figure 2. **Annual Electricity Generation by Source in Germany in 2020 (TWh)**



Source: Fraunhofer ISE[7]

The energy policy of Germany is predominately driven by the *Energiewende*, seeking the gradual phase-out of nuclear and coal power, while concurrently reducing greenhouse gas emissions through increased renewable energy production and energy efficiency improvements. Long-term goals plan for 80 per cent of electricity demand to be met by renewable generation by 2050, compared to the current average rate of 45 per cent.

As a result of dedicated policies and investment, Germany has experienced a remarkably rapid increase of renewable energy over two decades. However, the continued growth of renewable sources and stability of the power grid hinges on the expansion and improvement of the power grid. This includes both large-scale north-south transmission lines, but also upgraded low and medium distribution grids that can incorporate increased decentralized generators, energy storage and new smart technology and electric vehicles.

German power prices are among the highest in the European region. Despite wholesale electricity prices declining on average over the past decade, additional politically determined surcharges and taxes as well as grid fees (Table 1) have, in general, increased electricity bills for households. In 2020, the average consumer price in Germany for electricity was 0.3147 EUR/kWh (0.38 USD/kWh).[8]

Table 1. **Composition of Electricity Prices in Germany in 2020**

Breakdown	*Electricity price (USD/kWh)*
Generation cost	0.086
Grid cost	0.096
Electricity tax	0.025
VAT	0.061
Renewable energy cost	0.082
Offshore cost	0.012
Concessions	0.020

Source: STROM-REPORT[8]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of size of small hydropower (SHP) plants in Germany. The German Ministry for Economic Affairs and Energy recognizes that no international consensus on the definition of SHP currently exists. Despite accepting that definitions across the European Union place the limit at 10 MW, in Germany the limit is arbitrarily drawn at the plant size of 1 MW. The current Report uses the definition up to 10 MW.

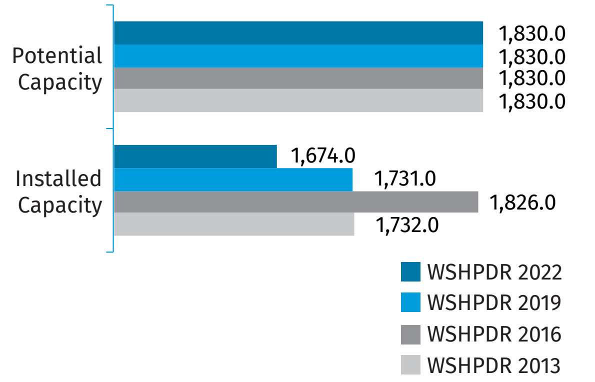
Germany has been a one of the global leaders in developing, installing and operating hydropower plants for over 100 years. The power plant stock of the country is characterized by a large number of SHP plants. Although SHP dominates the plant stock, the few large plants generate well over 80 per cent of the electricity of the entire hydropower sector.

No central register is kept specifically for hydropower plants in Germany, which means that the exact number of plants is unknown. This is due to the difficulty in keeping records of SHP plants, as many micro- and pico-hydropower projects used for self-consumption are difficult to identify. Therefore, the available data on the number of SHP plants in the country are based, to a certain extent, on estimates. In 2011, the existing data on hydropower plants were compiled by a survey of the German states and other institutions as part of a research project of the Federal Environment Agency. According to this survey, the total number of all hydropower plants in Germany is approximately 7,600.[9]

However, according to the Federal Association of German Hydropower Plants, in 2018 there were an estimated 7,300 hydropower plants in Germany with a total capacity of 5,600 MW. Approximately 6,900 of these plants had an installed capacity of less than 1 MW and nearly 80 per cent had less than 100 kW of installed capacity. According to the association data, the share of SHP plants under 1 MW in annual electricity generation is approximately 14 per cent.[10] Furthermore, based on the annual reports submitted by the transmission system operators to the Federal Network Agency, 6,249 SHP plants received compensation under the Renewable Energy Sources Act (EEG) in 2008, of which 80 per cent had less than 100 kW of installed capacity.[11] The locations of 406 plants with a capacity of more than 1 MW are known. The hydropower plants operated in Germany also include 31 pumped-storage plants, 11 of which have a natural inflow and therefore also produce renewable energy.[12]

According to the Bundesnetzagentur (the Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway), installed SHP capacity in Germany amounted to 1,674 MW in 2020 (Figure 3).[6] The decrease in installed capacity since the *World Small Hydropower Development Report (WSHPDR) 2019* is due to different definitions and measurements. In some calculations, private SHP plants are not included. Furthermore, the definition of 10 MW is not always followed, and many government websites include plants of up to 1 MW capacity, which make up the vast majority of SHP in Germany. According to the current information, however, the installed capacity of SHP plants has been almost constant over the last decade. There are no known plans for SHP development at the time of writing and the most recent known commissioning was in 2012 (Table 2). The available SHP potential is almost fully developed in Germany. The potential estimate of 1,830 MW is based on targets for exploitation of full economic potential by 2020, as outlined in the European Small Hydropower Roadmap, as no new feasibility studies are available.[13]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Germany (MW)**



Source: Federal Network Agency,[6] ESHA,[13] *WSHPDR 2013*,[14] *WSHPDR 2016*,[15] *WSHPDR 2019*[16]

Note: Data for SHP up to 10 MW.

Table 2. **List of Selected Operational Small Hydropower Plants in Germany**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Wasserkraftwerk Hausach	Hausach, Baden-Württemberg	0.4	4	Kaplan, run-of-river	E-Werk Mittelbaden	2012
Weserkraftwerk Bremen	Bremen	10.0	2–6	2x Kaplan, run-of-river	Weserkraftwerk Bremen GmbH & Co. KG	2012
Wasserkraftwerk Rebdorf	Rebdorf, Bavaria	0.1	2	–	Bistum Eichstätt	2011
Weserkraftwerk Bremen	Bremen	10.0	–	Run-of-river	Weserkraftwerk Bremen GmbH & Co. KG	2011
Prater-kraft-werk	Munich, Bavaria	2.5	6	Kaplan, run-of-river	Stadtwerke München	2010
Wasser-kraft-werk Johanniswehr	Hildesheim	0.3	4	Kaplan, run-of-river	EVI Energieversorgung Hildesheim	2009
Kraftwerk Oberföhring	Munich, Bavaria	1.0	5	Kaplan, run-of-river	E.ON	2008
Fuhlsbütteler Schleuse[	Hamburg	0.1	3	Kaplan, run-of-river	UWW Windstrom Wedel	2000
Kraftwerk Bad Abbach	Bad Abdach	3.5	5	Run-of-river	Uniper Kraftwerke GmbH	2000
Unterwasserkraftwerk Karlstor	Heidelberg	2.6	3	Underground, Kaplan	EnBW	2000
Wasserkraftwerk Dietfurt	Dietfurt	0.5	4	Run-of-river	Uniper Kraftwerke	1991
Kraftwerk Krün	Krün	0.2	5	Run-of-river	Uniper Kraftwerke	1990
Wasserkraftanlage Alte Schleuse	Hameln	1.3	5	Run-of-river	Stadtwerke Hameln	1988
Kraftwerk Dausenau	Dausenau	1.2	4	Kaplan, run-of-river	Süwag Energie	1986
Wasserkraftanlage Pfortmühle	Hameln	0.7	3	Kaplan-R, run-of-river	Stadtwerke Hameln	1986
Flusskraftwerk Auerbrücke	Pforzheim	1.0	4	2 x Kaplan, run-of-river	Stadtwerke Pforzheim	1985
Kraftwerk Nassau	Nassau	1.2		Kaplan, run-of-river	Süwag Energie	1985
Höchstädt	Bremen	9.9	–	Run-of-river	LEW Wasserkraft GmbH	1982
Kraftwerk Regensburg	Regensburg	7.2	5	3 x Kaplan, run-of-river	E.ON	1977
Speicherkraftwerk Lister	Attendorn	2.6	20	Kaplan, storage	LLK GmbH	1965
Kraftwerk Deizisau	Deizisau	2.0	5	Run-of-river		1963
Kraftwerk Offingen	Offingen	7.4	5	2 x Kaplan, run-of-river	Bayerische Elektrizitätswerke GmbH	1963
Werkskraftwerk Sappi Alfeld	Mühlenmarsch 1, Niedersachsen	0.1	--	Run-of-river	Sappi Alfeld GmbH	1912

Source: Federal Network Agency,[6] Wikipedia[17]

The majority of SHP plants are located in the mountainous southern provinces, with 50 per cent of all plants located in Bavaria and 20 per cent in Baden-Württemburg. These two states typically account for over 80 per cent of annual hydropower production in Germany. Electricity generation from hydropower can fluctuate year-on-year by 10–15 per cent depending on precipitation and river flows.[18]

RENEWABLE ENERGY POLICY

Feed-in tariffs (FITs) were introduced in Germany as part of the Renewable Energy Act (EEG) in 2000 as a measure to incentivize renewable energy deployment and production. FITs apply also to hydropower.[18] The FIT system has been amended several times. In 2014, it was amended to be applicable only to small-scale power plants. Most recently, with the revision of the EEG in 2021 (still in process at the time of writing), auctions became the standard process for the determination of tariffs which were previously fixed by State Governments. However, hydropower remains excluded from the auctioning system.[19] The duration of a FIT is 20 years, while the tariffs are revised every four years. The FIT under the current 2017 revision as well as the new 2021 revision under the EEG are displayed in Table 3. The revised EEG maintains the additional regulations on annual decreases (0.5 per cent) and on the fulfilment of the environmental protection standards.

Table 3. **FIT Rates in Germany under the 2017 and 2021 Revisions**

FIT – 2017 revision		*FIT – 2021 Renewable Energy Act*	
Capacity category	*Rate (USD/kWh)*	*Capacity category*	*Rate (USD/kWh)*
≤ 500 kW	0.15	≤ 500 kW	0.15
≤ 2 MW	0.10	≤ 2 MW	0.10
≤ 5 MW	0.08	≤ 5 MW	0.07
≤ 10 MW	0.07	≤ 10 MW	0.07
		≤ 20 MW	0.06
		≤ 50 MW	0.05
		> 50 MW	0.04

Source: Federal Ministry of Justice and Consumer Protection[20]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP development in Germany is regulated by European, Federal and State legislation. Federal legislation concerning environmental impacts, biodiversity, greenhouse gas emissions and renewable energy have all been formed or recently amended to adhere to the European Directives such as the Water Framework Directive, Habitats Directive and the Environmental Impact Assessment Directive.

The most important legislation for SHP in Germany is the Federal Water Resources Law (*Wasserhaushaltsgesetz*, WHG). Particularly relevant are the regulations that govern the damming, abstraction or diversion of river flows, which are only permitted if minimal environmental flows can be ensured. Any new dam infrastructure or change to operations must maintain or improve the quality of the water. For hydropower specifically, greenfield projects are only permitted when appropriate steps to preserve fish populations are implemented.[19] In Germany, the regulation and approval of hydropower projects is the responsibility of the State authorities to interpret and apply Federal legislation. Thus, SHP potential is limited in Germany, especially for new greenfield projects. However, potential exists in modernizing, upgrading or restarting existing plants.[21]

A 2010 report on hydropower potential in Germany commissioned by the German Government identified 450 potential new SHP sites for development with an average output of 200 kW, with a total capacity of 90 MW.[22]

COST OF SMALL HYDROPOWER DEVELOPMENT

The costs for the development of SHP plants in Germany are in the average range. On the one hand, the good infrastructure and the easy access to equipment manufacturers can lead to prices in line with the market. On the other hand, the costs for planning and development are in the upper range due to the high labour cost structure. Furthermore, high concession and market prices for rights and land can increase the overall development costs. High standards are also cost drivers.

FINANCIAL MECHANISMS FOR SMALL HYDROPOREW DEVELOPMENT

Under the FIT scheme there is a fixed remuneration for the electricity produced by hydropower plants available for a period of 20 years. It enables plant operators to plan and finance with certainty. For many SHP plant operators, direct self-consumption can be even more financially attractive if the share of self-consumed electricity is high.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

The German weather service predicts higher winter precipitation and drier summers in the country due to climate change. The total amount of precipitation may be higher or lower than today, depending on the region. Higher amounts of heavy precipitation are also to be expected.[11]

Since in Germany the currently highest precipitation amounts fall in summer, the spread will become more conspicuous due to climate change. A uniform water supply would not have any disadvantageous consequences for most hydropower plants. The total amount of rainfall will develop differently depending on the region. This means higher annual rainfall for some plants and lower annual rainfall for others. A clear trend across the country is not yet discernible. Heavy rainfall events can lead to hydropower plants having to adapt to increased maximum water volume.[12,23]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The development of SHP in Germany faces barriers of different types, related to complex licensing procedures:

- Existing plants: licensing is based on the assessment of the possible impact on stream ecology. This is valid for the optimization or the reactivation of already existing plants.
- New plants: new sites are licensed only after an approval procedure, which requires thorough assessments of environmental concerns with respect of European, Federal and State legislation. Few entirely new projects on suitable sites are realized. Expensive assessments are required to avoid any undesired impact on stream ecological systems. Furthermore, the required hydraulic structures and operation modes are usually of high quality and expensive. [24]

The enabling factors for SHP development include:

- The Renewable Energies Act of 2000 is the most important support instrument for SHP plants, allowing for a funding period of 20 years and, hence, enabling secure financing;
- The CO_2 tax introduced in 2021 will also make hydropower generation significantly more attractive in the coming years;
- The infrastructural conditions are excellent throughout Germany;
- Germany has one of the highest electricity prices worldwide with an average of 0.36 USD/kWh. Further increases in electricity prices will also be supportive for SHP plants.

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Luxembourg

International Center on Small Hydro Power (ICSHP)

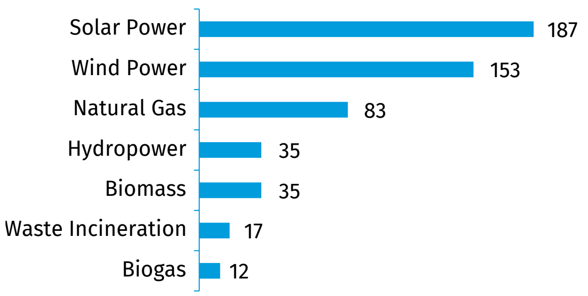
KEY FACTS

Population	638,639 (2021)[1]
Area	2,586 km^2 [2]
Topography	Luxembourg is a landlocked country, characterized by low mountains and rolling hills covered in green, dense forests. The highest point of the country is the peak Burgplatz, which reaches 559 metres above sea level. The southern region of Gotland has fertile lands and rivers. In contrast, the northern region of the country is a rigid plateau with an arid soil.[2]
Climate	The climate is mild with no dry seasons, typical for marine countries in the western part of Europe. The annual average temperature is 8.5 °C. In the winter, temperatures reach on average 3.3 °C during the day and -1.8 °C at night. Average high temperatures in the summer reach 21 °C, with lows of roughly 11.3 °C. The summers are thus generally cool and winters mild.[3]
Climate Change	Average air temperatures in Luxembourg have gradually increased over the years, particularly in the winter season. Mean annual temperatures are projected to rise to 11.6°C between 2071 and 2100. Temperature extremes also impact water quality in summer when the river flow is at its lowest.[4,5]
Rain Pattern	Rain falls throughout the year in Luxembourg. The month receiving the most rain is November, with an average rainfall of 83 mm.[5] The month with the least rain is April, with an average rainfall of 58 mm. The average annual rainfall is 850 mm.[6] The country also recorded its second wettest summer with an average of 336 mm of rain in 2021.[7]
Hydrology	The Moselle River is the lowest point in Luxembourg, at only 133 metres above sea level, and one of the most important rivers of the country. The Sûre and the Our are other major rivers and form the border with Germany. In the southern region, the Alzette River flows northwards, until it reaches the Sûre River.[8]

ELECTRICITY SECTOR OVERVIEW

In 2020, total electricity generation in Luxembourg amounted to 2,230 GWh (Figure 1). Hydropower, including the Vianden pumped-storage plant, accounted for roughly 49 per cent of the total produced electricity. In total, over 70 per cent of the electricity was generated from renewable energy sources. In 2020, Luxembourg imported 23,557 GWh of electricity and exported 3,883 GWh. Population gross demand for electricity was estimated at 7,540 GWh.[9]

Figure 1. **Annual Electricity Generation by Source in Luxembourg in 2020 (GWh)**

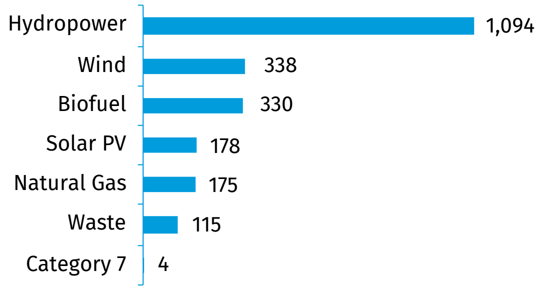


Source: IEA[9]

Luxembourg has a 100 per cent electrification rate and one of the lowest electricity consumption rates among the European Union (EU) member states. However, over 80 per cent of its electricity is imported. This makes the country highly dependent on electricity imports and therefore its energy sector policies are affected by the markets in the neighbour countries.[10,11,12]

The total installed capacity of power plants in Luxembourg between 2019 and 2020 increased from 488 MW to 522 MW, with the share of renewable energy increasing from 377 MW to 422 MW (Figure 2; these totals exclude the Vianden pumped-storage hydropower plant). This increase is mainly due to the commissioning of new wind power plants and new solar photovoltaic (PV) power plants. Since 2019, the solar PV capacity has steadily risen, with a 41 MW increase recorded in the first half of 2021.[10]

Figure 2. **Installed Electricity Capacity by Source in Luxembourg in 2020 (MW)**



Source: ILR[10]

Note: The installed capacity does not take into account the Vianden pumped-storage plant.

The largest share of electricity generated in Luxembourg comes from the Vianden pumped-storage hydropower plant, which accounted for 1,010 GWh in 2020. The hydropower plant Moselle–Sûre generated 92.9 GWh in 2019 and small private hydropower plants produced an estimated 4.8 GWh in the same year.[13]

There are multiple electricity suppliers in Luxembourg: Eida, Electris, Enovos, Leo, Nordenergie, Steinergy, Sudgaz and Sudstroum. The main provider of electricity is Enovos, however, certain municipalities might use specific private electricity suppliers. Creos is the subsidiary of Enovos that is in charge of the electricity grid in the country.[14] LEO, an important player in the country's energy market, is another subsidiary of Enovos and has the second largest market share, with 13 per cent in the residential sector and 28 per cent in the commercial sector. The main shareholder in Enovos is the Grand-Ducal State, therefore, most of the shares are owned by the Government of Luxembourg.[14]

La Société Électrique de l'Our (SEO) is one of the main renewable energy companies in the region and operates seven run-of-river hydropower plants on the Moselle River, including four in France. In collaboration with ENOVOS and through the company SOLER, it operates the Esch-sur-Sûre, Rosport and Ettelbrück hydropower plants owned by the Government of Luxembourg.[15]

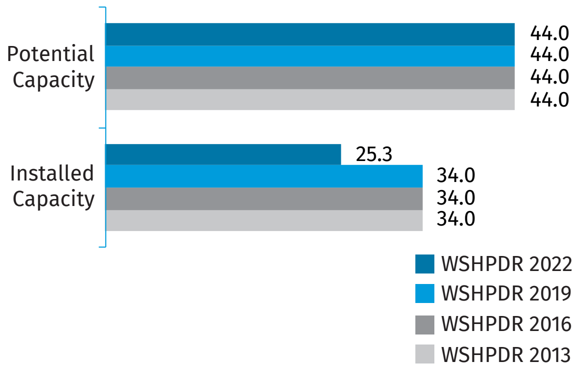
The average price of electricity is 0.210 EUR/kWh (0.237 USD/kWh) for households and 0.128 EUR/kWh (0.129 USD/kWh) for businesses, which is inclusive of the cost of power, distribution and taxes.[16] Distributors such as Enovos and LEO also offer a real green electricity plan. The scheme offers better tariffs for electricity produced from renewable energy sources, encouraging the adoption of renewable energy in the country. The Luxembourg Regulatory Institute also launched an online price comparison tool that allows users to compare prices offered by various suppliers and tariffs based on their location and energy consumption.[17]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in Luxembourg refers to plants up to 10 MW. In 2020, the installed SHP capacity of the country was 25.3 MW, including micro-hydropower plants (Table 2).[18] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity decreased due to the exclusion of the Esch-sur-Sûre plant, which has a capacity of 13 MW.[18] The SHP potential estimate has remained unchanged (Figure 3). The potential for hydropower development in Luxembourg is limited by the country's physical size and the lack of access to major water resources.[19]

In 2013, the European Small Hydropower Association (ESHA) reported that the Government of Luxembourg had planned to increase the installed capacity of SHP in the country to 44 MW.[20] However, there is no new information on the progress of this plan from the Government or private stakeholders. One study on the hydropower potential of existing water mills and weirs estimated that in Luxembourg there are 44 micro-hydropower sites per 1,000 km^2.[21]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Luxembourg (MW)**



Source: The Statistics Portal,[18] ESHA,[20] *WSHPDR 2013*,[22] *WSHPDR 2016*,[23] *WSHPDR 2019*[24]

According to Soler's latest updates, the company under the joint leadership of SEO and Enovos, the Rosport SHP plant must reach a good ecological status to fulfill the requirements of the European Water Framework Directive. To achieve the aforementioned status, the minimum flow must be considerably increased. The Government of Luxembourg will install a wastewater turbine near the existing dam to enhance minimum flow. The 7 MW Rosport SHP plant is located on the dam of the Sûre, in Rosport Ralingen. The plant is equipped with two vertical Kaplan turbines. The Rosport plant produces roughly 24 GWh per year.[25] In July 2021, the Rosport plant was heavily damaged by record high floods and has been out of service with no update on its reopening.[26] The Ettelbruck SHP plant is located on the Alzette River and generates 0.8 GWh per year. The installed capacity of the power plant is 200 kW. Ettelbruck was completely renovated in 1998 and operates today without any personnel, monitored remotely from Esch-sur-Sûre.[25] In addition to the mentioned SHP plants, there are also a number of smaller scale-plants, some of which are listed in Table 2.[27]

Table 2. **List of Selected Installed Small Hydropower Plants in Luxembourg**

Name	*River*	*Installed capacity (MW)*
Grevenmacher	–	7.80
Rosport	Sûre	7.00
Schengen	–	4.50
Nospelt	–	0.40
Ettelbruck	Alzette	0.20
Clouterie/Bissen	Attert	0.14
Moestroff	Sûre	0.14
Birtrange	Alzette	0.11
Cruchten	Alzette	0.11
Essingen	Alzette	0.09
Erpeldange	Sûre	0.09
Bounsmuhle	Syr	0.06
Bettendorf	Sûre	0.05
Bigonville	Sûre	0.05
Steckenmuhle	Syr	0.05
Bissermuhle	Attert	0.05
Felsmuhle	Syr	0.05
Stolzemburg	Our	0.05
Useldingen	Attert	0.05
Bannmuhle	Attert	0.04

Source: Industrie Luxembourg,[27] Lalieu[28]

RENEWABLE ENERGY POLICY

In 2018, the Ministry of Energy and Spatial Planning of Luxembourg published the National Energy and Climate Plan for Luxembourg (NECP LU). This plan highlights specific goals for greenhouse gas emissions reduction and raising the renewable energy share in the country's energy mix. It also aims to improve the energy efficiency of the country. Luxembourg aims to align national policies with the Paris Agreement, the European climate and energy framework 2030 and the European Green Deal Roadmap and to contribute at best to the common European goals. The Government has adopted a 2030 target to:

- Reduce the greenhouse gas emissions of the non-ETS (Emissions Trading System) sectors by 55 per cent compared to 2005, which exceeds the 40 per cent reduction required by the EU and aims below the 2/1.5 °C global temperature target;
- Increase the share of renewable energy in gross final consumption to 25 per cent, from 11 per cent in 2020;
- Reduce the end energy demand by 40–44 per cent compared to the EU-Primes Baseline projection (2007).

Taken together, these goals will require considerable investment in electricity infrastructure. However, it is unclear if existing policies and support schemes adequately address the problems presented by rapid population growth and a growing economy. Low energy prices for consumers are also a threat to investments needed in energy efficiency and renewable energy promotion.[12]

The initial regulation on renewable energy was amended in 2005, with feed-in tariffs (FITs) for electricity produced from renewable energy being established.[29] The tariffs are guaranteed for 15 years from the date of the first feed-in of electricity into the network.[30] FITs are available for SHP plants up to 6 MW (Table 3). Investment subsidies have been available since January 2010. Market premiums are also available but only apply to installations with a production capacity equal to or higher than 500 kW. In addition, under the general provisions of the Law on the Organization of the Electricity Market, power generation plants can use the electricity grid for applicable charges. However, renewable energy plant operators are exempt from grid usage fees and electricity from renewable sources is a preferred choice when compensating for power losses.[29]

Table 3. **Feed-in Tariffs for Small Hydropower in Luxembourg in 2019**

Plant size	*FIT (EUR (USD) per kWh)*
≤ 300 kW	0.179 (0.20)
> 300 kW and ≤ 1 MW	0.149 (0.17)
> 1 MW and ≤ 6 MW	0.124 (0.14)

Source: RES Legal[29]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are multiple barriers to SHP development in Luxembourg. Some of the most relevant are outlined below:

- The country's energy needs are mostly met through imports at present, therefore, there is no motivation to implement or approve the construction of new SHP projects;
- There is no well-defined energy strategy specific to SHP;
- The SHP potential in Luxembourg is very limited;
- Lack of feasibility studies in the sector makes it difficult to determine the true SHP potential;
- The licensing procedure for SHP projects is time-consuming and bureaucratic as numerous permits are necessary;
- The country's research and development policies focus on clean energy technologies, but not specifically on SHP, with higher interest in solar and wind power technology development.

The key enabling factors for SHP development include:

- Availability of support in the form of FITs, market pre-

miums and investment subsidies;
- Identified potential for developing micro-hydropower plants on existing water mills and weirs.

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The Netherlands

International Center on Small Hydropower (ICSHP)

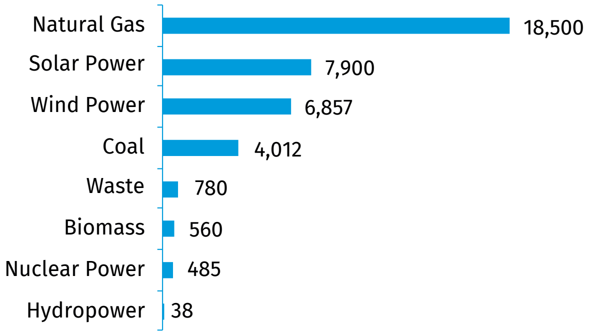
KEY FACTS

Population	17,441,500 (2020)[1]
Area	41,543 km^2 [2]
Topography	The Netherlands has a predominately low-lying, flat terrain. Approximately half of the territory lies no more than one metre above sea level and much of the coastal land is reclaimed land from the sea, or polders, lying below sea level. There is a region of hills in the south-west with elevations reaching 100 metres. The highest point in the country is Vaalserberg at 323 metres, located in the extreme south-west on the border junction with Belgium and Germany.[2]
Climate	The Netherlands has a maritime temperate climate. Summers are mild and cool with an average temperature of 17 °C in July. The Gulf Stream creates relatively mild winters with an average temperature of 2 °C in January. Cloudy skies and high humidity are very typical throughout the year.[2]
Climate Change	Effects of climate change have already been experienced in the Netherlands and are expected to continue. Average temperatures have risen approximately 1.7 °C in the past century and average precipitation has increased by 20 per cent. In the following decades, weather is expected to become more extreme with an increase of extended wet periods as well as an increase of extended dry periods. A sea level rise of between 35 cm and 85 cm is possible by the end of the century, which will put strain on the manmade water management structures the country has in place to maintain the coastal lands.[3]
Rain Pattern	Precipitation is distributed relatively evenly throughout the year (50–90 mm/month) with a slight increase during late summer and a slight decrease during spring. Average annual precipitation is 790–850 mm.[2]
Hydrology	The largest river is the Rhine, which begins in Central Europe and enters the Netherlands from Germany, flowing north-west to empty into the North Sea. Other major rivers are the Meuse and the Schelde, which begin in France, and the Eems, which begins in Germany. These rivers and their arms form the delta with its many islands. Together with numerous canals, the rivers give ships access to the interior of Europe.[4]

ELECTRICITY SECTOR OVERVIEW

In 2021, the Netherlands had approximately 39,132 MW of installed capacity, of which 39 per cent was with renewable energy sources. Natural gas accounted for 18,500 MW (47 per cent), solar power for 7,900 MW (20 per cent), wind power for 6,857 MW (18 per cent), coal for 4,012 MW (10 per cent), waste for 780 MW (2 per cent), biomass for 560 MW (1 per cent), nuclear power for 485 MW (1 per cent) and hydropower for 38 MW (less than 1 per cent) (Figure 1).[5] In recent years, wind power and solar power have been increasingly more important and have seen the largest increases in installed capacity, while installed capacity of coal has been steadily decreasing. As there are some solar photovoltaic (PV) units that are not part of the centralized grid, actual installed capacity of solar power is higher.[6]

Figure 1. **Installed Electricity Capacity by Source in the Netherlands in 2021 (MW)**

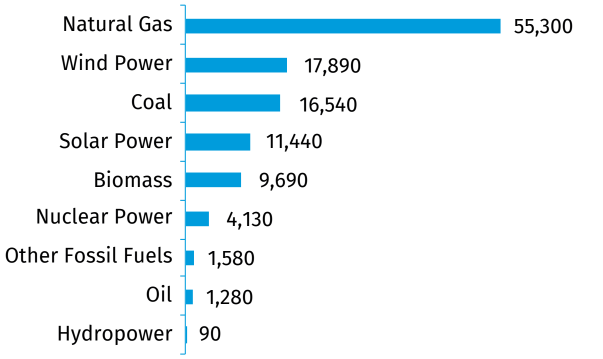


Source: ENTSO-E[5]

In 2021, total electricity generated in the Netherlands was approximately 117,940 GWh, of which 33 per cent was generated using renewable energy. Natural gas generated approximately 55,300 GWh (47 per cent), wind power 17,890 GWh (15 per cent), coal 16,540 GWh (14 per cent), solar power 11,440

GWh (10 per cent), biomass 9,690 GWh (8 per cent), nuclear power 4,130 GWh (4 per cent), other fossil fuels 1,580 GWh (1 per cent), oil 1,280 GWh (1 per cent) and hydropower 90 GWh (Figure 2). In the same year, 20,890 GWh of electricity was imported, much of which was nuclear power from Belgium, and 20,630 GWh was exported.[7]

Figure 2. **Annual Electricity Generation by Source in the Netherlands in 2021 (GWh)**



Source: CBS[7]

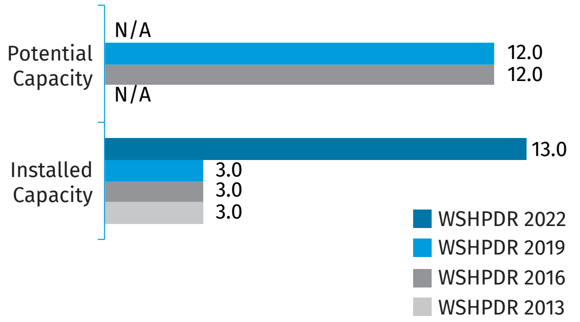
The electrification rate in the Netherlands is 100 per cent. The electricity sector is liberalized, a process that began with the Electricity Act of 1998 and was completed in 2004. While there are approximately 50 electricity supply companies in the country, the major six are Delta, EON, Eneco, Engie, Essent and Nuon.[8] The distribution and transmission systems are both publicly owned. The distribution system is split up into seven regional companies: Coteq, Enduris, Enexis, Liander, Rendo, Stedin and Westland Infra. The transmission system is fully operated by one company, TenneT. The transmission system crosses national borders in several locations and has interconnections with Belgium, Denmark, Germany, Norway and the United Kingdom, facilitating imports and exports of electricity.[9]

The Netherlands is a part of the wholesale electricity market in Europe that comprises over 20 countries to buy, sell and trade electricity. There are two nominated electricity market operators (NEMOs), Epex Spot and Nord Pool, which are responsible for the future and spot markets for the country. The prices of electricity are heavily influenced by the rest of Europe.[9] Consumer prices of electricity include the variable electricity price, an energy tax and an environmental tax. In 2021, the average final price for consumers was 0.26 EUR/kWh (0.28 USD/kWh), which included an average variable price of 0.11 EUR/kWh (0.12 USD/kWh), energy tax of 0.11 EUR/kWh (0.12 USD/kWh) and environmental tax of 0.04 EUR/kWh (0.04 US/kWh).[10] Due to the global increase of gas prices, average electricity prices for the year of 2022 were expected to be considerably higher.[11]

SMALL HYDROPOWER SECTOR OVERVIEW

The definition of small hydropower (SHP) in the Netherlands is up to 10 MW. The installed capacity of SHP is 13 MW while the total potential is unknown.[12] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has increased due to categorizing the Maurik hydropower plant with a capacity of 10 MW as SHP, which it previously was not considered to be. Since previous potential has been exceeded and no updated estimates are available, an accurate value for current potential has been updated as unknown (Figure 3). New potential capacity could be found by more accurate feasibility studies, in particular, at old watermill sites throughout the country.[13]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in the Netherlands (MW)**



Source: Microhydropower,[12] *WSHPDR 2019*,[14] *WSHPDR 2016*,[15] *WSHPDR 2013*[16]

The installed capacity being equal to the potential capacity indicates that all SHP opportunities that have already been identified and considered feasible have been developed. As the Netherlands is a very flat country, hydropower is not considered an important potential source of electricity generation.[17] Currently, hydropower accounts for less than 1 per cent of all electricity generation in the country, having generated 90 GWh in 2021 with its installed capacity of 38 MW. SHP represents approximately 34 per cent of all hydropower, while the other 66 per cent of large hydropower is concentrated in two locations, the Alphen aan de Maas plant with 14 MW and the Linne plant with 11 MW. The two SHP plants that have a capacity over 1 MW are the Maurik with 10 MW and the Hagestein with 1.8 MW (Table 1).[12] The remaining 1.2 MW of SHP in the country is distributed among 16 other plants, some of which are modernized centuries-old watermills.

Table 1. **List of Selected Small Hydropower Plants in the Netherlands**

Name	*Installed capacity (MW)*
Maurik	10.000
Hagestein	1.800
Roermond	0.200
Haandrik	0.100
Meerssen	0.035
Nederweert	0.035
Mechelen	0.020
Hackfort	0.005

Source: Microhydropower[12]

In addition to the hydropower plants, the country has potential for tidal SHP to be installed on the coastal structures regulating water outflow and on the sea-flood protection structures. The turbines on barriers at Afsluitsijk (IJsselmeer) were installed in 2008 and are used for tidal turbine development and feed the Dutch grid. Since autumn 2015, the tidal turbines installed on the storm-surge barrier in Oosterschelde operated with a total capacity of up to 1.2 MW.[18]

RENEWABLE ENERGY POLICY

Under the European Union Renewable Energy Directive (Directive 2009/28/EC), the Government of the Netherlands created the National Renewable Energy Action Plan of 2010. This plan committed to a target of 14 per cent of the country's final energy consumption to be from renewable energy sources by 2020, including at least 10 per cent of renewable energy in transport.[19] Although the share of renewable energy sources in the country's energy mix has strongly increased in the last years, the actual renewable energy share of final energy consumption in 2020 fell short of the target, with just over 11 per cent, and biofuels in transport accounted for less than 2 per cent.[20]

More recent renewable energy targets for 2030 and 2050 were stated in the Climate Agreement of 2019. This plan called for a reduction in carbon emissions by 49 per cent by 2030 and for renewable energy to generate at least 84 TWh.[21] In 2021, renewable energy generated just under 40 TWh, indicating that in order to reach the goal, renewable energy generation will have to more than double in the following nine years.[7] The Climate Agreement also includes the proposal to ban coal production from 2030 onwards and for 100 per cent renewable energy production by 2050.[21] The Climate Act passed in 2019 substantiates this target of carbon neutrality for 2050 and mandates that the Climate Action Plan must be reviewed every five years.[22]

Current instruments that promote the production of renewable energy include:

- Sustainable Energy Production and Climate Transition Scheme (SDE++);
- Obligation to use biofuels in the transport sector;
- Co-firing with biomass in coal-fired power stations;
- Import of renewable energy.[7,21]

The growth should mainly be sourced from wind power, biomass and solar PV. Hydropower is expected to account for less than 1 per cent of the total.

In most of Western Europe, energy producers are separated from the high-voltage grid. In the Netherlands, the grid operator does not distinguish between different electricity producers and is obligated by law to connect all parties to the grid and transmit electricity across the high-voltage grid. Under the Electricity Supply Act of 1998, transmission operators are required to connect all new installations to the grid, without discrimination.[19]

Financial incentives for renewable energy development are mainly supported by the operating grant of the Stimulation of Sustainable Energy Production and Climate Transition (SDE++) scheme and the Energy Investment Allowance tax deduction. The SDE++ is available for the production of renewable electricity, renewable gas, renewable heat and the renewable combination of heat and electricity. The SDE++ offers 12- or 15-year financial security by subsidizing unprofitable project components. The subsidy is the difference between a basic amount (cost price of the renewable energy) and the energy market price. The Government of the Netherlands determines a maximum SDE++ budget for each year and the budget for 2021 was EUR 5 billion (USD 5.4 billion).[23]

For hydropower plants, the subsidy term is for 15 years. Different amounts are offered for hydropower plants with a drop of less than 50 cm, more than 50 cm and for hydropower renovations with a new turbine and the subsidy is given in four different phases with each phase having a different value. Based on the type of hydropower and the phase, the scheme provides between 0.0579 EUR/kWh (0.062 USD/kWh) and 0.1097 EUR/kWh (0.12 USD/kWh) for between 2,600 and 5,700 working hours.[23]

The Energy Investment Allowance grants the ability to offset a certain percentage of investments in renewable energy production against income taxes, both personal and corporate. The exact percentage changes every year and for the year of 2021 it was 45.5 per cent.[24].

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The main limitations for SHP development in the Netherlands include:

- Hydropower potential is low due to the flat relief;
- Local water communities ("Waterschappen") are reluctant to issue permits;
- The development of SHP is hindered due to the lobby of fishermen (recreational and professional).[14]

The main enablers for SHP development in the Netherlands include:

- Old watermill sites could be modernized to install SHP plants;
- Further comprehensive feasibility studies could uncover additional SHP potential.[13,17]

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Switzerland

Pedro Manso & Mathieu Barnoud, MHYD Water & Energy Solutions Sàrl

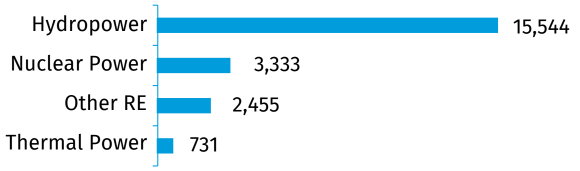
KEY FACTS

Population	8,419,550 (2019)[1]
Area	41,277 km^{2} [2]
Topography	Switzerland mostly consists of mountains, with the Alps in the south and the Jura Mountains in the west and north-west, and a central plateau with large lakes. The highest summit is the Pointe Dufour/Dufourspitze at 4,634 metres above sea level.[3]
Climate	Switzerland has a temperate climate, which varies with elevation and with location relative to the main Alpine ridge. Winters are cold and cloudy, with rain and snow, whereas summers are humid, cool to warm and occasionally hot, with frequent thunderstorms along the main Alpine ridge.[2] Selected average temperatures vary from -10 to +9 °C (low) to -4 to +17 °C (high) across the country. [3]
Climate Change	The Alps, and therefore Switzerland, are affected by global warming, the main consequences being the retreat of melting glaciers and the increase of the snowfall altitude limit. Extreme weather events, such as heat waves or bad weather and floods, are also expected to become more frequent. Climate change is likely to influence the frequency, intensity and seasonality of landslide activations, rockfalls, debris flows, wet snow avalanches and floods. Changes in runoff availability are expected to increase competition for water uses.[3]
Rain Pattern	Switzerland experiences frontal and orographic rainfall, with 2,000 mm/year of average precipitation in the northern foothills of the Alps, in the Alps and in southern Switzerland; 1,000-1,500 mm/year in the lowlands north of the Alps; and between 500 and 700 mm/year in Valais and Grisons regions. The amount of precipitation during the summer semester (April–September) is nearly double that of the winter semester, except in the Canton of Valais. From an elevation of 1,200-1,500 metres above sea level, precipitation during winter usually occurs as snowfall.[2] Due to climate change, average precipitation on a large scale is expected to change on a seasonal but not annual level. According to current climate models considering a temperature increase of approximately 2 °C, winter precipitation will increase by up to 24 per cent and summer precipitation will decrease by up to 39 per cent by the end of the century.[3]
Hydrology	The share of precipitation available for runoff depends on evapotranspiration and temporal storage (as snow, ice or underground). In Switzerland, the potential evapotranspiration decreases with elevation going from the central plateau to the alpine areas, due to decreasing temperatures and less intensive land use. Rivers exhibit a variety of runoff regimes, which mainly differ depending on the role played by snow and ice storage in the contributing catchment. Mountain rivers exhibit monthly peak flow during spring and summer due to snow and ice melt. Lowland rivers have low flow months in summer due to evapotranspiration and extended dry spells.[4] Higher temperatures will not necessarily lead to a nationwide increase in evaporation but could cause significant water loss locally (up to 6 mm per day). Swiss glaciers are predicted to lose between 76 and 98 per cent of their current ice volume by 2100, hence, glacier melt contribution to runoff will become virtually non-existent by the end of the century. Higher temperatures in the Alps will change the precipitation type from solid (snow) to liquid, which in turn will lead to more runoff in winter. Overall, the timing of melting peak will occur earlier in spring and the melt volume will be smaller as a result of reduced snow storage. In Alpine areas, glacier retreat, shrinking permafrost and shorter snow cover will lead to greater sediment availability, which is expected to increase sediment yield above 1,400 metres above sea level.[3]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in Switzerland are hydropower and nuclear power, accounting for 57.4 per cent and 33.6 per cent, respectively, of total production, which amounted to 70.9 TWh in 2020 (including 4.5 TWh from pumped-storage plants).[4] Production from thermal power plants (non-renewable and renewable) accounted for 6.4 TWh, or 9 per cent of the total electricity production (Figure 1). The total consumption summed up to 59.6 TWh in 2020 (including 4.2 TWh of transmission and distribution losses). Electricity consumption has remained stable in recent years, with efficiency gains offsetting positively the demographic growth and the increase in electrical household heating. However, the winter electricity supply depends on imports (between 500 and 10,000 GWh per winter semester in the past 11 years). Over the last consolidated year of statistics (2020), hydropower produced 15.4 TWh in winter (Q1 & Q4) and 22.3 TWh in the summer semester (Q2 & Q3).[4]

Figure 1. **Annual Electricity Generation by Source in Switzerland in 2020 (TWh)**



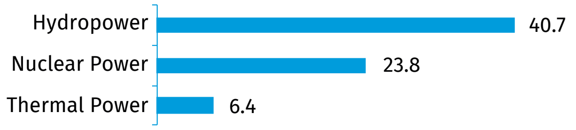
Source: Swiss Federal Office for Energy[4]

Note: The thermal power category includes both renewable and non-renewable sources.

In 2011, Switzerland decided to gradually withdraw from the production of nuclear energy. Consequently, a long-term energy policy, termed Energy Strategy 2050, was outlined to guarantee a safe electricity supply.[5,6] In September 2016, the Parliament formally accepted a first set of measures of this strategy, approved by a universal referendum in May 2017. The strategy focuses on improving energy efficiency, expanding renewable energy production, adopting an active foreign energy policy and, where necessary, ensuring electricity imports and/or local production from fossil fuels. Renovation and expansion of the grid infrastructure is also among the objectives of the strategy; aggregation of parallel lines from different operators is ongoing to improve efficiency, reduce transmission bottlenecks within the country and at international connections. Renewal of transmission lines more than forty years old is also underway in view of handling larger numbers of decentralized producers feeding electricity into the grid.

Currently, 674 hydropower plants with a capacity of at least 300 kW operate in Switzerland.[4,7,8] A 49 per cent share of the total hydropower production comes from run-of-river plants, 47 per cent from storage plants and 4 per cent from pumped-storage plants. According to the official energy statistics, in 2019 Switzerland had 15,544 MW of effective installed hydropower capacity (vs. 15,575 MW forecasted), 3,333 MW of nuclear capacity, 2,455 MW from other renewable energy sources and 731 MW of thermal capacity, resulting in a total of 22,063 MW of installed capacity from all sources (Figure 2).[4]

Figure 2. **Installed Electricity Capacity by Source in Switzerland in 2019 (MW)**



Source: Swiss Federal Office for Energy[4]

Note: Data for 2019.

The Energy Strategy 2050 foresees an increase of hydropower efficiency and generation: annual hydropower generation should reach at least 37.4 TWh by 2035 and at least 38.6 TWh by 2050. New pumped-storage plants should help increase energy storage and support the integration of solar and wind power plants. Winter supply and operation flexibility remain the main challenges.

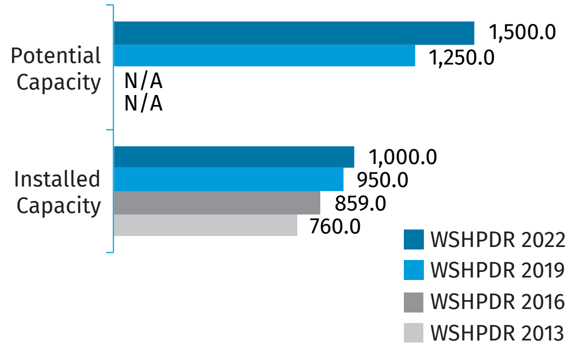
In the short to medium term, imports of electricity and the deployment of gas power plants are the available solutions for guaranteeing the electricity supply in winter. The importance of renewable sources other than large hydropower in the Swiss energy mix is slowly increasing, following progressive steps towards a nuclear phase-out. Incentives to the deployment of renewable sources such as small hydropower (SHP), solar power, wind power and biomass exist in multiple forms. These incentives are regularly revised to account for increased technology maturity and reduced deployment costs. However, wind power and SHP face significant opposition from local stakeholders and non-governmental organizations. Geothermal power plants face not only public opposition due to fears of induced seismicity, but also still struggle to develop cost-effective technical solutions allowing for a viable business plan. The supply of electricity must be fully identified by source, which has recently led utilities to replace grey supplies with mostly domestic nuclear production.

Swiss electricity tariffs operate under an open market and prices are determined by supply and demand. Tariffs are regulated by the Electricity Commission (ElCom), which monitors fees for network use and is responsible for prohibiting unjustified or excessively high rates. The tariff for using the transmission grid is defined by Swissgrid, while tariffs for the use of the distribution grid are determined by the network operators. Tariffs may vary depending on market procurement rates and costs of production on site.

SMALL HYDROPOWER SECTOR OVERVIEW

In Switzerland, SHP refers to plants with a mean gross hydraulic power of up to 10 MW.[8] As of 2019 and following a detailed inventory, approximately 1,400 SHP plants were in operation in the country (of which 487 plants were between 300 kW and 10 MW), with an overall installed capacity of approximately 1,000 MW (of which 939 MW were from plants between 300 kW and 10 MW) and an annual production of approximately 4,100 GWh (of which 3,808 GWh were from plants between 300 kW and 10 MW).[9] Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity increased by 5 per cent, whereas the potential grew by 20 per cent (Figure 3). SHP represents roughly 5.8 per cent of the national electricity production and 10.1 per cent of the total hydropower production. Tables 1 and 2 present a non-exhaustive list of recently commissioned SHP plants and planned SHP plants, respectively.

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Switzerland (MW)**



Source: Swiss Federal Office of Energy,[6] Swill Small Hydro,[9] *WSHPDR 2013,*[11] *WSHPDR 2016,*[12] *WSHPDR 2019*[13]

Note: Installed SHP capacity reported in *WSHPDR 2016* did not include data for plants up to 300 kW.

Table 1. **List of Selected Operational Small Hydropower Plants in Switzerland**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Mitlödi (Föhnen/Sool)	Mitlödi	4.00	35	Run-of-river	Mitlödi (Föhnen/Sool)	2020
Schächen, Schattdorf	Schattdorf	4.90	85	Run-of-river	Schächen, Schattdorf	2020
Oberwald	Oberwald	6.25	236	Run-of-river	Gere Kraftwerk	2020
Churwalden	Churwalden, Bärgliwäg	0.35	233	Run-of-river	Churwalden	2019
Grida, Churwalden	Churwalden, Grida	0.36	340	Run-of-river	Grida, Churwalden	2019
La Moille, Finhaut	Finhaut	0.42	159	Run-of-river	Turbinage des Torrents Finhaut	2019
Le Bruet, St - Triphon, Ollon	St - Triphon Com. Ollon, Bruet	0.62	585	Run-of-river	MCE Le Bruet	2019
Chapfensee	Mels, Plons	0.65	46	Run-of-river	KW Chapfensee	2019
Dietikon-Dotierzentrale	Dietikon	0.77	3	Run-of-river	Dietikon-Dotierzentrale	2019
Crans-Montana	Crans-Montana, R. Bourgeoisie	1.05	183	Run-of-river	Centrale du Lac d'Igogne	2019
Breithorn, Blatten	Blatten	1.70	214	Run-of-river	KW Breithorn-Faflertalp AG	2019
Vionnaz - l'Avançon	Vionnaz	2.20	804	Run-of-river	Vionnaz - l'Avançon	2019
Gadastätt, St. Antönien	St. Antönien	2.22	126	Run-of-river	Kraftwerk Schaniela	2019
Eggli, Walenstadt	Walenstadt	3.14	356	Run-of-river	Kraftwerk Berschnerbach AG	2019
Grafenau, St. Gallen	St. Gallen, Grafenau	0.31	3	Run-of-river	Kraftwerk Grafenau	2018
Mühlebach II, Engi	Engi, Unter Engi	0.53	38	Run-of-river	Kraftwerk Mühlebach AG	2018
Weissenstein, Mels	Mels, Plons	0.64	558	Run-of-river	KW Weissenstein	2018
Mädems-Parmort	Mels	1.76	399	Run-of-river	Kraftwerk Mädems-Parmort	2018
Fellitobel, Gurtnellen	Gurtnellen	2.30	347	Run-of-river	KW Gurtnellen	2018
Eaux du torrent du Fossau	Vouvry	2.30	521	Run-of-river	Eaux du torrent du Fossau	2018

Source: Swiss Federal Office of Energy[14]

Table 2. **List of Selected Ongoing/Planned Small Hydropower Projects in Switzerland**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Developer*	*Planned launch year*	*Stage of development*
Ovella Dotierzentr. Nauders	Nauders. A	0.3	2	Run-of-river	Gemeinschaftskraftwerk Inn	2021	Construction
Madonna degli Angeli	Giubiasco	0.3	702	Run-of-river	Madonna degli Angeli	2021	Construction
Uister Chiipelfurä, Kippel	Kippel	5.2	49	Run-of-river	Kraftwerk Wiler Kippel AG	2021	Construction

Covatanne	Vuiteboeuf	0.6	151	Run-of-river	Arnon Energie SA	2022	Construction
Au Bévieux	Bex	4.2	77	Run-of-river	Saline de Bex SA	2022	Construction
Glarey	Bex	1.7	39	Run-of-river	ERA SA	2023	Detailed design

Source: Swiss Federal Office of Energy[14]

Among these SHP plants, an estimated 900 have installed capacity below 300 kW and account for only 1 per cent of hydropower production. This group represents the remaining ones of a high number of the small-scale plants (approximately 7,000) that were operating in Switzerland at the beginning of the 20th century. These plants could be refurbished and contribute to the growth of SHP production. However, the best sites in the country are already in use. In fact, as of October 2020, 651 plants with a total installed capacity of 500 MW benefited from feed-in-tariffs (FITs), producing on average 1,776 GWh/year.[10] Exploiting the remaining potential is under debate, both from the economic and the ecological perspectives.

New technologies are under development to harvest hydraulic energy on existing infrastructure (e.g., drinking water and wastewater networks, tailrace channels). Social acceptance of such plants is high. The federal authorities are sponsoring the required engineering developments (e.g., of new turbines), under the Hydropower Research Programme managed by the Federal Office of Energy.

The Energy Strategy 2050 indicates an available SHP potential of up to 110 GWh/year in present conditions, which may even increase to 550 GWh/year if design and implementation practices are improved and social acceptance is increased.[6] In 2020, the total potential capacity of SHP plants was estimated at approximately 1,500 MW. This value is obtained by taking into account the average design and operating conditions of SHP plants in Switzerland.[9] Therefore, the 20 per cent increase in potential capacity compared to the *WSHPDR 2019* is due to access to more detailed and technical information.

In Switzerland, SHP projects with 1–10 MW of capacity can apply for financial support with the implementing agency Pronovo AG instituted by the Swiss administration. As of October 2020, there were 234 applications from SHP projects awaiting a decision, representing a total capacity of 245 MW and an estimated production of 821 GWh/year.[10] However, there are no funds left to finance them before the FIT will expire in 2023. Also, several SHP plants are part of the list of national priority projects of hydropower plants producing more than 10 GWh/year.[15,16]

SMALL HYDROPOWER PROJECTS AVAILABLE FOR DEVELOPMENT

Table 3 shows a list of SHP projects available for investment.

Table 3. **List of Small Hydropower Projects Available for Investment in Switzerland**

Name	*Location*	*Potential capacity (MW)*	*Type of site (new/ refurbishment)*
Val Curciusa	Grison	~10	New
EES+	Valais	~10	New
Wynau 2e étape	Bern	~10	New
Jaberg-Kiesen / Aare Thun-Bern	Bern	~10	New
Litzirüti-Pradapunt	Grison	~10	New

Source: Swiss Federal Office of Energy[15]

RENEWABLE ENERGY POLICY

The Swiss energy policy is defined by the energy and water articles of the Federal Constitution and is detailed in the Acts on Energy, on CO_2, on Nuclear Energy, on Electricity Supply, on the Protection of Waters, on Hydropower and on Spatial Planning.[5] In particular, the Energy Act defines the regulatory framework for renewable energy, while the Waters Protection and Hydropower Acts regulate the field of hydropower planning and operation. Other relevant regulations are the Fishery Act, the Environmental and Forestry Protection Acts and the Nature and Cultural Heritage Act.

The Energy Strategy 2050 is a key milestone of the Swiss energy policy.[6] As mentioned, this strategy focuses on the exploitation of energy potential from increased energy efficiency, hydropower and new renewable energy sources. The Swiss Energy Programme is the instrument specifically developed to implement the energy and climate objectives of the Federal Government and of the cantons. In particular, cantons determine strategies for the building sector, sustainable energy supply, energy planning and energy efficient mobility and by means of financial incentives promote the efficient use of energy and of waste heat. The Renewable Energy Action Plan sets targets for advancing renewable energy production.

The Federal Government promotes electricity production from renewable energy sources through two main economic instruments: cost-covering FITs and one-off investment grants.[17] The cost-covering FIT bridges the gap between the market price and the cost borne by producers of electricity from renewable sources. This tariff is available for hydropower plants (up to an annual-average capacity of 10 MW), solar photovoltaics (PV) (starting from an installed capacity of 10 kW), wind and geothermal power, biomass and biological waste and is applicable for 15 years (10 years for biomass power plants). For existing facilities being object of reconversion, previous investments in water conveyance (e.g., intake works, waterways and penstocks) are eligible for a tariff bonus if carried out in the past 20 years, promoting good asset management. Tariff rates are regularly reviewed to take into account technological progress and increasing maturity of new technologies. The reviewed tariffs only apply to new production facilities. One-off investment grants are available for SHP plants above 300 kW of capacity that are being renewed and/or expanded. In addition to the described mechanisms of financial support, non-financial measures have been set in the Energy Act, such as priority dispatch (i.e., supply companies must purchase electricity from independent producers).

Economic, social and environmental barriers for the development of SHP are effectively addressed in Switzerland, for example, through the cost-based FIT and the involvement of communities in renaturing rivers that are or will be affected by plant operation. A water platform promoting dialogue among stakeholders is currently being organized. The focus of the last roundtable discussion was to develop a common basic understanding of the challenges facing hydropower against the background of the Energy Strategy 2050, the net-zero emissions target and the objectives pertaining to the security of supply and the preservation of biodiversity.[18] Research efforts aiming to address the arising questions receive support from the federal authorities. Additional barriers result from the complex regulatory context, which for SHP involves complying with legislation on water and energy, environment and development planning, at the federal, cantonal and municipal levels. The Energy Strategy 2050 attempts to address these issues by simplifying and harmonizing administrative procedures throughout the country. Examples of needed interventions include (i) the establishment of a single contact point for SHP plants (only available for wind power so far) as there are numerous topics to be addressed and the concerned municipalities do not have the required experience, and (ii) a checklist for project promoters, the possibility to bundle applications for several installations along the same river and the expansion of the Hydropower Research Programme of the Swiss Federal Office for Energy.[19]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

SHP plants are regulated by the same legislation as larger hydropower projects. The main legislation and regulation documents in Switzerland concerning hydropower projects are:

- The Energy Act (2018);
- The Water Power Act (1916) ref. 721.80;
- The new Electricity Supply Act (2007) ref. 734.7.

In addition to these federal documents, each canton has specific legislation following the main principles defined at the federal level.

COST OF SMALL HYDROPOWER DEVELOPMENT

The construction costs of SHP plants are very site-specific. The main investment cost indicators in Switzerland are the installed capacity and the head: the higher the head the lower the investment cost; the same applies to the plant size. However, the costs also depend on the power plant operation, energy output and lifetime, which are paramount to assess the unit cost of a kWh produced (or levelized cost of electricity, LCOE). The Swiss Small Hydro association regularly provides an overview of the sector and costs (Table 4).[9] The cost-covering remuneration tariffs linked to the subsidies do not tell the whole story as the concession period and the lifetime of an SHP plant significantly exceed the subsidized period, with the residual value of net present value assessment being an important matter of discussion.

Table 4. **Mean Costs of Small Hydropower Construction in Switzerland**

Installed capacity (kW)	*Construction unit cost (CHF/kWh (USD/kWh))*
0–50	0.13 (0.13)
50–300	0.10–0.17 (0.10–0.17)
300–1,000	0.08–0.12 (0.08–0.12)
1,000–10,000	0.04–0.10 (0.04–0.10)

Source: Swiss Small Hydro[9]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

Subsidies for promoting renewable energy (including SHP) are financed through a levy on every kWh consumed in Switzerland. With the introduction of the Energy Act (LEne) that came into force on 1 January 2018, the subsidized FITs are now governed via a system of direct marketing.[16] This new system is available for SHP plants from 1 MW to 10 MW of capacity; and SHP owners can request this subvention until the end of 2022. Furthermore, investment contributions are available for renovations and expansions until 2030. The aim of direct marketing is to make the FIT system market-oriented. Under the new system, the producers themselves are responsible for selling the electricity they produce. To this end, they conclude individual purchase agreements with utility companies or energy service providers, which creates an incentive to design and operate plants according to the demand. In addition to the proceeds from the sale of electricity, the plant operators receive a technology-specific feed-in premium, which is designed to cushion long-term market price fluctuations and, thus, provides producers with extensive investment security. To compensate for the costs of direct electricity marketing, producers also receive a technology-specific management fee.

It is also possible to have electricity production from SHP certified as "naturemade", i.e., as being of hydraulic and ecological origin. Anyone who orders electrical products from "naturemade" star-certified hydropower plants contributes to an ecological improvement fund: one CHF cent per kWh of electricity sold. This money is used to carry out regular ecological improvement projects in the catchment area of the plants.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Precipitation variability is expected to increase in Switzerland as a consequence of climate warming. As SHP plants in the country are mostly without seasonal storage possibilities, the down-times of the plants increase due to extended dry spells as well as during floods, when floating debris and sediment-laden flows hamper plant operation. Furthermore, natural hazards are likely to increase with climate change and therefore floods, rock falls and landslides will negatively affect SHP plants.

On the other hand, changes in the runoff pattern may result in more electricity generation from SHP plants in the short term. Indeed, changes in the snow melt and glacial melt, as well as in snow cover extension, will affect runoff generation mainly during late spring and in summer at altitudes above 1,400 metres above sea level and increase runoff in the winter semester, which may provide additional opportunities for SHP development.

BARRIERS AND ENABLERS TO SMALL HYDROPOWER DEVELOPMENT

In general, SHP provides a sound contribution to Swiss society. The development of new SHP projects is hampered mainly by:

- Conflicts with other water uses/rights in densely populated (lowland) areas, including with new restoration projects of impaired river reaches as required by the Waters Protection Act.
- Difficulties to come up with appropriate and cost-effective solutions for access and electricity transmission lines for greenfield projects in natural creeks. The social perception that individual SHP plants have (too) small a contribution to large societal needs (e.g., energy transition targets) raises public concern regarding the local and cumulated ecologic impact on small pristine river valleys in remote areas.
- Poorly engineered projects, with reduced teams and limited skills, often lead to production overestimation and costs underestimation.[19] Improvement of engineering design of SHP projects (often overlooked due to the associated high cost per kWh) and introduction of environmentally friendly solutions at new and existing facilities are required in order to enhance public acceptance. Improved engineering design should focus on properly sized facilities based on available water resources and site conditions, as well as on innovative management and environmental flow rules. The ecologic, technical and economic feasibility must be assessed in the early phases of the project, which implies mobilizing skilled engineering teams, to reduce uncertainty regarding water availability and potential energy production, as well as investment costs, too often poorly addressed in early stages. When hiring a skilled engineering team may prove too costly for a single small or micro-hydropower project, one alterative option is bundling several studies together.
- Raising of the incentive thresholds, following the approval of the new energy transition law and the entry into force of the new ordinance (in January 2018), to a minimum power of 1 MW in fluvial projects or 300 kW for rehabilitation projects, except for any synergetic projects combined with other industrial water uses that have no direct impact on the natural or high-ecological interest river reaches.
- Excessive production of legal and regulatory documents: despite the stable legal framework (updates carried out in general every 20 years), the operational directives and financial incentive mechanisms tend to change in shorter timeframes. This reflects the interplay between the different competing renewable energy technologies and their marginal interest but hampers developers from engaging in projects. Synergetic projects where hydropower is one among other purposes (e.g., solar power, water supply, drought-support, ecological restoration) tend to find better support with the authorities, the public and funding partners than stand-alone SHP projects.
- Competition with other renewable energy sources, in particular solar PV plants with appurtenant electrochemical storage. There is fierce competition in the public space for media attention to obtain public acceptance and financial support from the public authorities at cantonal and federal level.
- Public concerns about the reduction of biodiversity in Swiss river corridors based on monitoring and assessment over recent decades, which have led to increased pressure on SHP promoters, operators and authorities to mitigate negative impacts on biodiversity as well as on requests for further investment (for projects which can otherwise be eligible for public funding).

Enablers for SHP development in Switzerland include:

- Large availability of water across the country, increased by the glaciers melting due to climate change. Besides, mountains cover a major part of the territory, which enables SHP plant implementation with high water head.
- Due to more than 150 years of large hydropower development across Switzerland, methodologies of hydropower project implementation, including SHP plants, are well-known to responsible institutions. This ensures a relatively quick and systematic reaction from the federal offices and enables acceptation of this kind of projects by the population.
- The hydropower sector development, including SHP projects, is actively encouraged in Switzerland. In-

deed, the Energy Strategy 2050 presents an objective of hydropower production increase of 1.2 TWh/year in 2050. To encourage hydropower development, including SHP, the Swiss Confederation provides subsidies to investors (for projects with an installed capacity above 1 MW).
- Due to a large number of existing hydropower infrastructure in the country, there is significant experience in construction and operation of hydropower plants, as well as qualified workforce for design, construction, operation and maintenance.

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5. Oceania

5.1. Australia and New Zealand

Countries: Australia, New Zealand

INTRODUCTION TO THE REGION

The electricity sector of Australia is spread over the expanse of the Australian mainland; the electricity grids of Queensland, New South Wales, Victoria, Tasmania and South Australia are interconnected into the National Electricity Market (NEM), but Western Australia is serviced by a separate Wholesale Electricity Market (WEM). There are many electricity transmission companies in the country, and market regulations as well as tariffs vary widely by territory. By contrast, the New Zealand electricity grid is fully interconnected. Even following a degree of decentralization, the nationwide transmission operator Transpower remains state-owned, the Government maintains a controlling stake in four of the five major electricity producers and there is little variation in electricity tariffs across the country.

Generation of electricity in Australia is dominated by fossil fuels, which accounted for 58 per cent of installed capacity in 2021 and 76 per cent of generation in 2020. Recent development in renewable energy sources has primarily targeted wind and solar power, which had both overtaken hydropower in electricity generation by 2020. Hydropower in Australia plays a supporting role. Despite considerable installed capacity, generation from hydropower has been on a continuous decline in recent years, decreasing by approximately 23 per cent between 2013 and 2020. In New Zealand, hydropower forms the mainstay of electricity generation, accounting for 57 per cent of installed capacity and 56 per cent of generation in 2020. Gas- and coal-fired thermal power plays a supporting role, with a significant share of its installed capacity on stand-by to balance loss of hydropower generation in dry years. New Zealand is also a leading global user of geothermal energy.

An overview of key indicators in the electricity sectors of Australia and New Zealand is provided in Table 1.

Table 1. **Overview of Australia and New Zealand**

Country	*Total population (million people)*	*Electricity access, total (%)*	*Electricity access, rural (%)*	*Total installed capacity (MW)*	*Electricity generation (GWh/year)*	*Hydropower installed capacity (MW)*	*Hydropower generation (GWh/year)*
Australia	26	100	100	56,284	265,232	8,130	14,807
New Zealand	5	99	99	9,505	42,845	5,389	23,988
Total	-	-	-	**65,789**	-	**13,519**	-

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The definition of small hydropower (SHP) in Australia includes plants with an installed capacity of ≤ 10 MW. In New Zealand, there is no formal definition of SHP and no regulatory measures governing SHP specifically, but plants with an installed capacity of ≤ 50 MW are customarily considered SHP plants.

A comparison of installed and potential SHP capacities in the region is provided in Table 2.

Table 2. Small Hydropower Capacities in Australia and New Zealand (MW)

Country	*Local SHP definition*	*Installed capacity (local def.)*	*Potential capacity (local def.)*	*Installed capacity (<10 MW)*	*Potential capacity (<10 MW)*
Australia	≤ 10 MW	175.0	N/A	175.0	175.0*
New Zealand	≤ 50 MW	475.0	N/A	146.8	489.8
Total	**-**	**-**	**-**	**321.8**	**664.8**

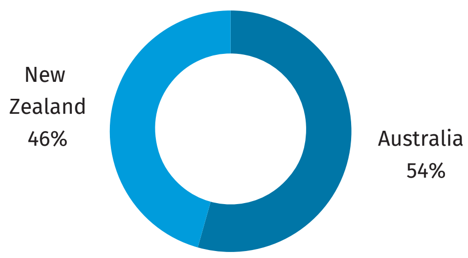
Source: *WSHPDR 2022*[1]

Note: *Based on installed capacity, as no data on potential capacity is available.

The total installed capacity of SHP ≤ 10 MW in Australia and New Zealand is 321.8 MW, while potential capacity is estimated at 664.8 MW. Relative to the *World Small Hydropower Development Report (WSHPDR) 2019*, the total installed SHP capacity in Australia and New Zealand has decreased by approximately 2 per cent, while the estimated potential capacity decreased by 16 per cent. In both countries, SHP accounts for only a small share of the total installed capacity of hydropower. For SHP ≤ 10 MW, this share is equal to 2 per cent in Australia and 3 per cent in New Zealand. However, given the greater prominence of hydropower in the energy mix of New Zealand, SHP plays a proportionately greater role in its electricity sector. Little or no new SHP development has occurred in Australia since 2014, while in New Zealand, recent activity has been mostly limited to the renovation of existing SHP plants rather than the construction of new plants. With no reliable data on remaining undeveloped SHP potential in Australia, the SHP sector in the country can be considered at full capacity, but considerable undeveloped SHP potential remains in New Zealand.

The national share of regional installed SHP capacity by country is displayed in Figure 1, while the share of total national SHP potential utilized by Australia and New Zealand is displayed in Figure 2.

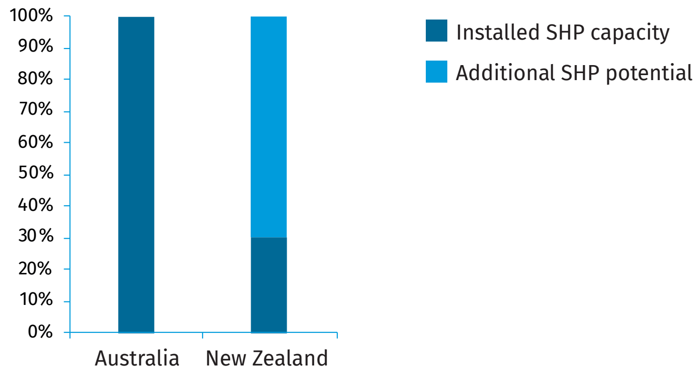
Figure 1. **Share of Regional Installed Capacity of Small Hydropower by Country in Australia and New Zealand (%)**



Source: *WSHPDR 2022*[1]

Note: For SHP ≤ 10 MW.

Figure 2. **Utilized Small Hydropower Potential by Country in Australia and New Zealand (%)**



Source: *WSHPDR 2022*[1]

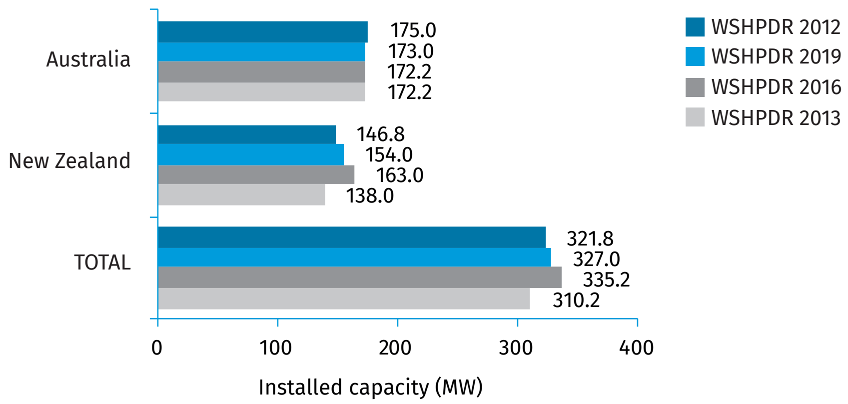
Note: For SHP ≤ 10 MW.

The total installed capacity of SHP ≤ 10 MW in **Australia** is 175 MW from approximately 65 plants. The installed capacity of SHP in the country has changed little since 2014, with different estimates contained in different editions of the *WSHPDR* reflecting differences in data quality rather than actual changes in installed capacity. No nationwide estimates of SHP potential in the country are available. Local inventories of hydropower potential on rivers undertaken by regional governments suggest a significant theoretical potential in parts of the country, for example, ≤ 1,000 MW in New South Wales. However, little or none of this potential is socially or environmentally feasible due to water scarcity issues and potential impacts on fish populations and the consequent social opposition to further hydropower development.

In **New Zealand**, the total installed capacity of SHP ≤ 10 MW is 146.8 MW, while under the local definition of SHP ≤ 50 MW, it is 475 MW. Undeveloped potential for SHP ≤ 10 MW has been estimated at 343 MW, bringing the total potential capacity to 489.8 MW if existing installed capacity is included. This suggest that approximately 30 per cent of the existing potential for SHP ≤ 10 MW has been developed so far. The SHP sector of New Zealand had once seen robust development, driven in part by the efforts of local communities to build and operate SHP plants for their own needs. However, in recent years, activity in the sector has been scarce and mostly focused on the renovation or reconstruction of existing SHP plants, with total installed capacity decreasing by approximately 10 per cent relative to the *WSHPDR 2016* as part of this process. In 2020, one new SHP plant with an installed capacity of 4 MW was commissioned and another 1.9 MW project was approved for construction.

Changes in the installed SHP capacities of countries in the region are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower from *WSHPDR 2013* to *WSHPDR 2022* by Country in Australia and New Zealand (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

Note: For SHP ≤ 10 MW.

Climate Change and Small Hydropower

Climate change presents an additional challenge to SHP development in the region. Australia concentrates hydropower generation in the south-eastern region and Tasmania. These regions have experienced a 25 per cent decrease in rainfall since 1970. However, the net summer rainfall has increased across the country, increasing the regional and seasonal differences. Similarly, New Zealand expects to experience increased variability in precipitation and inflow. The higher variability could challenge SHP plants' performance and lead to generation shortfalls in the summer months, while still meeting the electricity demand in winter.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Renewable energy projects in **Australia** are incentivized through the sale of renewable energy generation certificates by generators to electricity retailers, but no measures target SHP development specifically. While future SHP development on natural watercourses in Australia is unlikely, hidden SHP potential exists on manmade water supply infrastructure including irrigation canals, existing non-powered dams, water mains, pressure break tanks, and outflow from industrial sites. The development of SHP at such sites could be attractive for commercial and non-commercial entities for the purpose of self-consumption. However, no estimates of such hidden SHP potential are available.

The biggest obstacles to further SHP development in **New Zealand** are environmental considerations and restrictive environmental legislation in particular. Incentives exist in the form of a carbon trading scheme for financing renewable energy investments, as well as an Avoided Cost of Transmission (ACOT) payments available to SHP producers in particular. These, coupled with rising electricity prices stemming from the ban on gas exploration, could energize future SHP development in the country.

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Australia

Niels Nielsen, Kator Research Services, and Danila Podobed, International Center on Small Hydro Power (ICSHP)

KEY FACTS

Population	25,739,256 (2021)[1]
Area	7,688,287 km^2 (including islands)[2]
Topography	There are few mountains in Australia, with the exception of the Great Dividing Range, which reaches from Queensland to Victoria, with other parts of the country situated at low elevations. The highest point in the country is Mount Kosciusko (2,228 metres) and the lowest is Lake Eyre (-15 metres).[3]
Climate	The climate in the central part of Australia is arid, temperate along the southern coastal regions and tropical in the north of the country. Conversely, some mountainous regions experience cool winters and snow. The maximum temperature ranges from 18 °C to 40 °C and minimum temperature ranges from 3 °C to 21 °C, with a mean of 12–27 °C and a minimum range of 3–21 °C.[4]
Climate Change	The annual average temperature in Australia has increased by 1°C since 1910, with much of the increase having taken place since 1950. The period of 2013–2016 was marked by four of the five warmest years on record in the country. Projected climate change includes an increase in the number of extremely hot days and days conducive to wildfires, especially in southern and eastern Australia, while rainfall is expected to decrease across the southern part of the country in the winter and spring seasons.[5]
Rain Pattern	Rain patterns are monsoonal in the north and variable elsewhere.[3] Annual rainfall ranges from more than 3,000 mm to less than 100 mm.[6]
Hydrology	The largest water system in Australia is the Murray-Darling basin, which rises in New South Wales and Queensland, flows through Victoria and enters the sea in South Australia. Hydropower plants have been built along the Snowy River system in New South Wales and Victoria, as well as in Tasmania, but many of the country's rivers are ill-suited for major hydropower development.

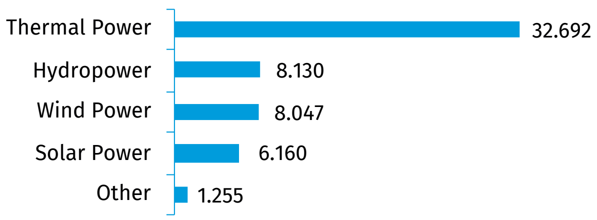
ELECTRICITY SECTOR OVERVIEW

The electricity sector of Australia is undergoing a paradigm shift. New wind and solar photovoltaic (PV) power capacity is being built at a rate of approximately 5 GW per year, which is sufficient to exceed the target of 70 per cent of total installed capacity to be provided by renewable energy sources (RES) by 2030. Wind and solar power comprise virtually 100 per cent of newly commissioned generation capacity and are replacing retiring coal and gas power plantss.[7,8] Despite these developments, as of 2021 generation from fossil fuels still formed the mainstay of the electricity sector.[9]

The contribution of hydropower to the country's total renewable energy generation has fallen significantly in recent years, largely due to the rapid rise of wind and solar power. However, with several large pumped storage projects being planned or already under construction as of 2022, the technology will continue to play a vital role in the clean energy future of Australia.[8]

The total installed capacity of producers operating within the National Electricity Market (NEM) of Australia amounted to 56,284 MW at the end of 2021, with thermal power including coal-fired, gas-fired and oil-fired power plants contributing 32,692 MW (58 per cent) of the total, hydropower contributing 8,130 MW (14 per cent), wind power contributing 8,047 MW (14 per cent), solar power contributing 6,160 MW (11 per cent) and other sources contributing 1,255 MW (2 per cent) (Figure 1).[9] However, some additional capacities operate separately on the Wholesale Electricity Market (WEM), with a total registered generation capacity of approximately 6 GW.[10]

Figure 1. **Installed Electricity Capacity by Source in Australia in 2021 (MW)**

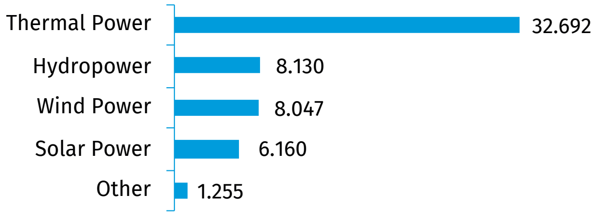


Source: AER[9]

Note: Data on NEM only.

Electricity generation in Australia reached 265,232 GWh in 2020, with thermal power from fossil fuels providing 200,566 GWh (nearly 76 per cent) of the total, large- and small-scale solar power providing 23,842 GWh (9 per cent), wind power providing 22,607 GWh (9 per cent), hydropower providing 14,807 GWh (6 per cent) and bioenergy providing 3,410 GWh (1 per cent) (Figure 2). A significant portion of the generated electricity, 16 per cent nationwide and ≤ 55 per cent in certain regions, was generated off-grid by self-consumers, including households, mining and manufacturing.[11]

Figure 2. **Annual Electricity Generation by Source in Australia in 2020 (GWh)**



Source: Department of Industry, Science, Energy and Resources[11]

Generation from hydropower has been steadily declining in recent years, decreasing by approximately 23 per cent between 2013 and 2020. At the same time, the hydropower sector plays a critical role in Australia in balancing generation from variable energy sources. Several large pumped-storage hydropower (PSH) projects are currently in development or planning stages, the most significant being the 2,000-MW Snowy 2.0 PSH plant and the Battery of the Nation PSH project with a planned capacity of approximately 2,500 MW.[8,12,13] The prospects for the development of additional river-based hydropower plants in Australia are quite limited.

Many coal-fired power plants in Australia are reaching their end of life and at least two thirds are expected to be retired within the next 20 years.[14] The cheapest replacement is likely to be solar and wind power, which means that the current high deployment rates of these technologies are likely to increase.[15, 16] At the end of 2020, 76 new large-scale wind and solar power projects were under construction in the country, representing 8 GW of planned capacity.[8]

The rate of electricity access in Australia is 100 per cent.[17] During the 2020–2021 financial year, domestic consumption of electricity in the NEM amounted to 188.6 TWh, decreasing from 192.4 TWh in the 2019–2020 financial year, while peak demand reached 31,945 MW.[18,19]

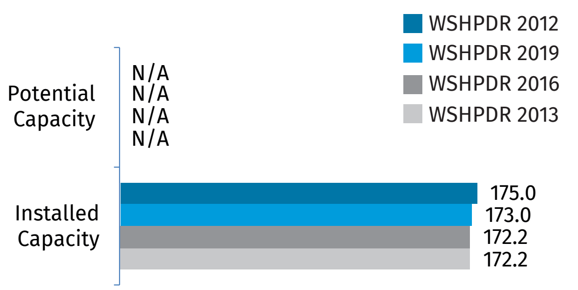
Tariffs for electricity consumers in Australia are highly variable and depend on the territory, provider and category of consumer, typically including a fixed charge and a variable charge based on consumption volume. The electricity market is deregulated in some regions but regulated in others where Government-owned companies act as the primary electricity provider (such as Western Australia and the Northern Territory). Tariffs in New South Wales, south-east Queensland and South Australia are partially regulated by the Electricity Retail Code, introduced in 2019. The Code provides a reference price for consumers, thus informing the retail prices set by providers.[20,21,22]

The NEM of Australia previously operated with a 30-minute settlement window. Many industry players lobbied for this window to be shortened to five minutes, arguing the change will result in lower prices for wholesale electricity and eventually lower prices for consumers, which would favour new market entrants. The switch to 5-Minute Settlement (5MS) took place on 1 October 2021. It is expected that the change will additionally favour certain fast-response energy technologies, including hydropower, that can increase or decrease output within a five-minute window, at the expense of existing coal- and gas-fired power plants which cannot.[23,24]

SMALL HYDROPOWER SECTOR OVERVIEW

Small hydropower (SHP) is defined in Australia as hydropower plants with an installed capacity of ≤ 10 MW. While more than 75 per cent of the installed hydropower capacity of Australia comes from large hydropower, there were approximately 65 SHP plants operating in the country as of 2014, with a total installed capacity of slightly over 175 MW.[25] No new data on SHP capacities in the country have been made publicly available since then. The 1 per cent increase in installed capacity of SHP relative to the *World Small Hydropower Development Report (WSHPDR) 2019* is a result of access to more accurate data. No reliable estimates of SHP potential in the country are available (Figure 3).[26]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Australia (MW)**



Source: Geoscience Australia & BREE,[25] *WSHPDR 2019*,[26] *WSHPDR 2013*,[27] *WSHPDR 2016*[28]

The theoretical SHP potential for Australia has not been quantified, though it is understood that some individual energy companies have undertaken local inventories. There are also some historic regional assessments of larger hydropower schemes that include some SHP sites. For example, the 2013 Renewable Energy Action Plan issued by the Government of New South Wales suggests a potential hydropower capacity of 1,000 MW in the state, mostly pertaining to small and mini-hydropower.[29] However, it is unlikely that any new hydropower plants will be developed in the country in the near future. This is primarily because of environmental and social considerations as well as the sporadic and unpredictable weather patterns in much of the country. As an example, the Murray-Darling River basin has many sites that could be suitable for SHP from a technical perspective, but the potential environmental impact (mainly on fish) precludes them from development.[30]

The most realistic direction for ongoing and future development of SHP in Australia lies in the so-called "hidden and untapped hydropower opportunities", referring to methods of increasing generation from hydropower at new and existing project sites that are often overlooked. These methods include development of new equipment in low-head applications, improvements to the efficiency of existing generating units as well as the addition of generating units to previously non-powered infrastructure including non-powered dams, drainage and irrigation canals, water distribution pipelines and outflow from industrial sites. One proposed application involves the addition of hydropower turbines at the inlets of pressure break tanks used in the mining sector to manage overpressure in the mine water supply system. Such units, representing an energy recovery system that would produce significant electricity cost savings for the operating company, could realistically possess an installed capacity of nearly 13 kW and generate as much as 110 MWh of electricity annually per unit, depending on the duration of tank inflow. Total energy recovery for a typical mining operation through the uniform application of this technology is estimated at ≤ 300 kW, translating into ≤ 2.5 GWh of electricity annually.[31]

RENEWABLE ENERGY POLICY

The development of RES in Australia is realized under the framework established by the Renewable Energy Target (RET), a set of mechanisms and thresholds for large- and small-scale RES promotion underpinned by the Renewable Energy Act 2000. The Large-scale Renewable Energy Target (LRET) incentivizes large RES projects through the creation and sale of large-scale generation certificates (LGCs), carried out by the licensed generators themselves and purchased by entities with liabilities under the LRET scheme, mainly electricity retailers. An analogous small-scale generation certificate (SGC) scheme is in place for small-scale RES producers such as individual households, who typically assign the right to issue certificates to an agent in return for a lower price on the RES system at the time of purchase.[32] The RET for annual generation from RES was set to increase steadily to 33 TWh by 2020 and is to be maintained at this level for the next decade (until 2030).[33]

In the absence of an updated Federal RET for 2020 onwards, several states and territories have legislated their own RETs. Table 1 displays the RET of each territory or state, expressed as a share of generation produced by RES.

Table 1. **Renewable Energy Targets in Australia**

State or territory	*Renewable Energy Target (%)*	*Year*
Australian Capital Territory	100	2020
Victoria	50	2030
Queensland	50	2030
Northern Territory	50	2030
South Australia	75 (RET), 25 (Storage)	2025
New South Wales	No RET, but has a target for zero emissions	2050
Western Australia	No target adopted	N/A

Source: ACT Government,[34] State Government of Victoria,[35] Queensland Government,[36] Territory Renewable Energy,[37] Slezak,[38] Parkinson,[39] Perpitch[40]

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change in Australia has led to significant drying in parts of the country, particularly in southern Australia, with a 19 per cent decrease in rainfall observed since 1970 and a 25 per cent decrease since 1996, relative to the long-term average. At the same time, net summer rainfall across the continent has increased over the last 30 years, particularly in the northern part of the country. The ongoing changes are likely to increase the regional and seasonal differences in rainfall in a country that already experiences high levels of variability in precipitation.[5]

Hydropower generation in Australia has been experiencing a steady decline since the early 2000s due to drought and variability in rainfall, decreasing at a rate of over 4 per cent a year between 1999 and 2008, while the hydropower share in total generation has been declining since the late 1970s. According to one study, generation from hydropower in 2029-2030 is expected to remain at 2007–2008 levels but will continue to lose ground to other energy sources as a share of total generation, making up just over 3 per cent of generation by 2030 despite ongoing development.[41]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Opportunities for SHP development on rivers and streams in Australia are limited. The barriers to the development of SHP in the country include the following:

- Small hydraulic heads lead to expensive generation that is unable to compete with wind and solar power;
- Negative environmental impacts, such as the impact on aquatic flora and fauna, restrict the availability of sites for SHP development;

- Hydrology is unpredictable and unsuitable for SHP, with unreliable river flows, droughts and floods;
- No reliable nationwide data on SHP potential;
- Climate change causing a decrease in overall hydropower generation potential;
- Social opposition to dam construction.

Enablers for SHP development in Australia include:

- The potential for the development of off-river SHP, particularly on existing water supply infrastructure in municipal systems, the mining sector and elsewhere;
- Progressive regional policies favouring RES development;
- Demand for SHP development by commercial and non-commercial entities for self-consumption.

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New Zealand

Bryan Leyland, Consulting Engineer

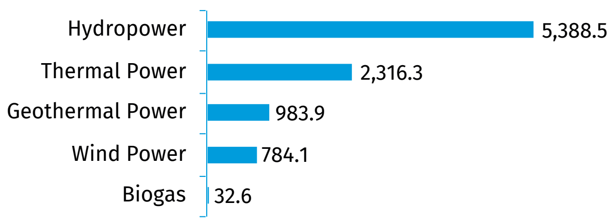
KEY FACTS

Population	5,000,000 (2020)[1]
Area	268,838 km^2[2]
Topography	The country comprises the North and South Islands, Stewart Island, the Chatham Islands and some small islands further north and south. The topography is generally hilly with several volcanoes and associated features such as hot springs. There is a major mountain range (the Southern Alps) running the length of the South Island. Mount Cook, the highest mountain, is 3,724 metres high.[2]
Climate	The climate of New Zealand is complex and varies from warm subtropical in the far north to cool temperate in the far south, with severe alpine conditions in the mountainous areas. The mean annual temperatures vary from 10 °C in the south to 16 °C in the north and temperatures generally drop by 7 °C for every 100 metres in altitude.[3]
Climate Change	The effects of climate change in New Zealand have already been felt in the form of rising sea levels. Under severe climate change scenarios, the country would experience increased periods of heavy rainfall and more variation in mean precipitation, an increase in the number of dry and hot days as well as a decrease in the number of cold nights (minimum temperature of 0 °C or lower). By 2040, mean temperatures are projected to increase by 0.7-1 °C and by 0.7-3 °C by 2090.[4]
Rain Pattern	Rainfall is reasonably steady during the year and usually reaches a maximum in late winter and early spring. Autumn and early winter are often dry. Rainfall ranges from 600 mm to 1,600 mm per year. There is little indication that it is affected by climate change.[5]
Hydrology	The Waikato River is the main river in the North Island. Its source is Lake Taupo with an altitude of 356 metres in the centre of the North Island. The river runs generally north from Lake Taupo and its mouth is on the north-western coast. In the South Island, the major rivers from a hydropower point of view are the Waitaki, which has its source in Lakes Tekapo and Pukaki and the Clutha, which has its source in Lake Whakatipu. All three lakes have glacial origins.

ELECTRICITY SECTOR OVERVIEW

In 2020, New Zealand had an installed capacity of 9,505 MW (Figure 1) and peak demand of approximately 7,000 MW.[6] Hydropower provides the majority of the electrical energy in the country. The remainder is predominantly provided by geothermal power, gas, wind power and coal, with minimal contributions from solar power and waste heat.[6] Due to its isolated location, there are no interconnections to other countries. Since 2014 the load has flattened off and is now steady at approximately 45,000 GWh per year. In 2020, electricity generation totalled 42,845 GWh (Figure 2).[6] New Zealand was a pioneer in rural electrification. For many years, more than 99 per cent of the population has had access to the grid.

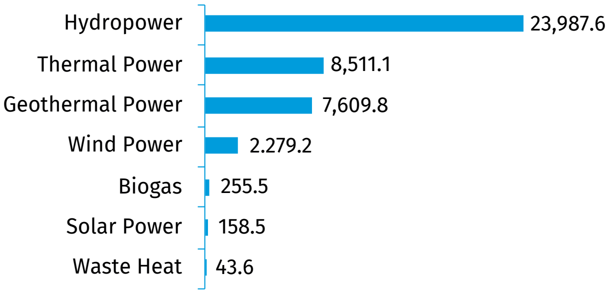
Figure 1. **Installed Electricity Capacity by Source in New Zealand in 2020 (MW)**



Source: MBIE[6]

Note: Small-scale sources such as solar power are not included.

Figure 2. **Annual Electricity Generation by Source in New Zealand in 2020 (GWh)**



Source: MBIE6

Most of the hydropower generation in New Zealand is owned by four large generators, three of which are 50 per cent Government-owned. Generating plants are well maintained and there is a regular programme of refurbishment of plants that vary in age from 30 to 90 years. No new large hydropower developments are under construction or contemplated even though the undeveloped potential is at least 2,000 MW.[7] The lack of action in the sector is influenced by the vagaries of the electricity market, which make it impossible to predict how much a power plant might earn in the long term, and by environmental activism demanding the rivers to remain in their natural state.

One of the key factors in power supply in New Zealand is ensuring that sufficient electricity is available during low rainfall years when hydropower generation drops by approximately 4,000 GWh — roughly 10 per cent of annual generation. Traditionally, the shortfall has been made up by a coal-fired power plant at Huntly and by increasing gas-fired generation.[8]

New Zealand already has a considerable amount of geothermal generation, which provides a low-cost, continuous and reliable supply. It is believed that the geothermal power resource could support approximately 2,000 MW of new generation. Some wind power capacity is under construction but at least 5,000 MW will be needed to achieve the country's electrification policy goals. However, this might make the dry year situation even worse because wind power in New Zealand is at a minimum in the autumn/winter when inflows are low and the demand peaks. However, with new gas exploration banned by the Government and existing fields declining rapidly, it is not yet clear what source of generation will replace the wind shortfall during peak periods. In an emergency, New Zealand has very large amounts of coal and a 750 MW gas- and coal-fired steam power plant that can burn coal when necessary to keep the lights on. Load growth is expected to accelerate in the future because more new houses will be built and the Government is keen on a significant switch to electric cars and increased use for industrial heating.

Up until 1991, most of the electricity distribution and all of the electricity transmission was carried out by the New Zealand Electricity Department, a government organization. Distribution was carried out by approximately 60 local Electric Power Boards. Many of them originated when local people got together to build a small hydropower (SHP) plant to supply electricity to the locality. Virtually all of these small plants have been connected to the grid. Between 1989 and 1991, it was decided that power supply should be corporatized under Government ownership and the Electricity Corporation of New Zealand was set up.[9] Not long after the transmission line section was split off as Transpower. The changes resulted in considerable improvements in efficiency and reduction in bureaucracy.

An electricity market was set up in 1993 with generators bidding into the market at the price at which they were prepared to generate. All generators were paid the price bid in by the most expensive generator. As it turned out, this market was not suited to a system where the cheapest generation was old and depreciated but perfectly good hydropower plants. Since the market became fully operational, electricity prices steadily increased at a rate well above inflation. Between 2018 and 2021 wholesale electricity prices have more than doubled and hydropower generators have made windfall profits at the expense of the consumer.

New Zealand has a 1,200 MW direct current link between the North Island and the South Island. In normal years it transmits surplus hydropower from the South Island to the North Island. In years when the rainfall in the South Island is low, it transmits power south from thermal stations in the North Island. The New Zealand electricity grid operates at 220 kV AC and +/-350 kV DC. Sub-transmission is at 110 kV. Distribution voltages are 66 kV, 33 kV 11 kV and 400/230 V.

There are five major generators in New Zealand. Three of them — Genesis Energy, Mercury Energy and Meridian Energy have 51 per cent Government ownership, with the remaining shares being held by public and various corporations. Contact Energy, the fourth major generator in the country, is 100 per cent public-owned. The fifth major generator, Pioneer, is smaller than the other four and was formed by aggregating the ownership of most of the SHP plants (less than 50 MW) previously owned by distribution authorities. There are also a number of individual generators who own geothermal power, wind power, SHP or gas-fired plants. Most generators are also retailers who sell to individual consumers; they also sell into the spot market. Experience shows that selling into the spot market is often the best option for a small generator in the long run.

The electricity industry in New Zealand is supervised by the Electricity Authority. However, there is no entity responsible for ensuring that the country has an adequate and reliable electricity supply. New power plants are built by generators if they believe that there is a reasonable chance that they will be profitable over the next 10–20 years. Economics favour building plants that can be built quickly rather than investing long term.

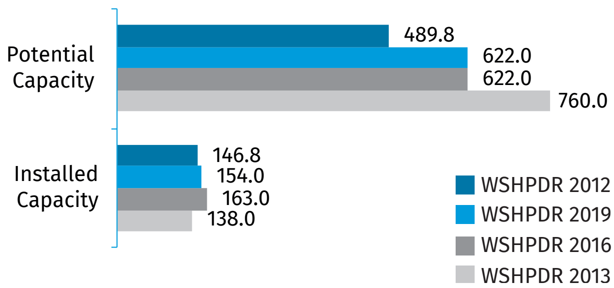
Domestic electricity tariffs are made up of charges for kWh, transmission and distribution. The average domestic tariff is approximately 0.20 US$/kWh.[10] ≤ a few years ago the spot price averaged 0.05 US$/kWh, but between 2018 and 2021 it has more than doubled even though little new capacity has been added. This increase has not yet showed up in the domestic price. Market prices are affected by the amount of water stored in the hydropower reservoirs, the state of the coal stockpile, the availability of gas and whether or not the wind is blowing. In general, prices vary little over the whole country but there can be major disparities at times due to transmission constraints.[11,12]

SMALL HYDROPOWER SECTOR OVERVIEW

In New Zealand there is no official definition for SHP, although a de facto definition is usually regarded as 50 MW or less. The lack of a need for a strict definition can be explained by the fact that SHP receives no special treatment. For the purposes of comparison, the present Report uses the ≤ 10 MW definition.

SHP ≤ 10 MW contributes 146.8 MW of installed capacity to the country's energy mix (Table 1) or 475 MW if the definition of 50 MW is being considered.[13] The SHP potential is estimated at 489.8 MW, of which 343 MW is undeveloped. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has decreased by approximately 10 per cent due to the replacement of a few aging projects with new ones. The change in potential capacity from the *WSHPDR 2019* is due to the availability of new geospatial data (Figure 3).[14]

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in New Zealand (MW)**



Source: Leyland,[13] MBIE,[14] *WSHPDR 2013*,[15] *WSHPDR 2016*,[16] *WSHPDR 2019*[17]

Note: Data for SHP ≤ 10 MW.

Table 1. **List of Selected Operational Small Hydropower Plants in New Zealand**

Name	*Location*	*Capacity (MW)*	*Operator*	*Launch year*
Matiri	Murchison	4.8	Pioneer Energy	2020
Normanby	Hawera, Taranaki	1.0	Renewable Power Ltd	1903, 2015
Amethyst	Westland	7.6	Westpower	2013
Rochfort	Westport, West Coast	4.2	Kawatiri Energy	2013
Rimu	Hastings	2.4	Trustpower	2013
Toronui	Hastings	1.4	TrustPower	2013
Talla Burn	Central Otago	2.6	Talla Burn Generation	2010
Kowhai	Central Otago	1.9	Pioneer Energy	2010
Cleardale	Ashburton	0.9	MainPower	2010
Matawai	Gisborne	2.0	Clearwater Hydro	2009
Deep Stream	Clutha	5.0	TrustPower	2008
Mangapehi	Waikato	1.6	Clearwater Hydro	2008
Feredays Island	Canterbury	0.3	Kea Energy	2005
Falls	Central Otago	1.3	Pioneer Energy	2003
Opuha	Mackenzie	7.5	Opuha Water / TrustPower	1999
Horseshoe Bend	Central Otago	4.3	Pioneer Energy	1999
Kaimai 5	Western Bay of Plenty	0.4	TrustPower	1994
Patea	South Taranaki	N/A	Trustpower	1984
Paerau	Central Otago	10.0	Trustpower	1984
Patearoa	Central Otago	2.3	Trustpower	1984

Source: Leyland[13]

There is some activity in the SHP business, which is benefiting from the 30 per cent increase in wholesale prices that took place in 2020 and can be expected to continue for at least three more years. In 2020, a 4 MW plant was commissioned in 2020 and a 1.89 MW plant was approved (Table 2).[18,19] As of early 2021, there were no other SHP plants in the planning stage.

Table 2. **List of Planned Small Hydropower Projects in New Zealand**

Name	*Location*	*Capacity (MW)*	*Plant type*	*Stage of development*
McCullochs Creek	Whataroa, South Westland	1.89	Run-of-river	Approved

Source: Hydro Review[19]

A GIS modelling study performed in 2020 identified 236 MW of theoretical SHP potential capacity (Table 3).[14] When comparing the results of the study with the existing literature, the total theoretical potential for sites from 1 MW to 10 MW was estimated at 343 MW. This study focused solely on run-of-river type sites.

Table 3. **List of Selected Small Hydropower Projects Available for Development in New Zealand as of 2021**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/refurbishment)*	*Type of project*
Site ID 73	Canterbury	8.5	20	New	Run-of-river
Site ID 60	West Coast	8.7	21	New	Run-of-river
Site ID 61	West Coast	8.3	20	New	Run-of-river
Site ID 31	Manawatu-Wanganui	7.4	20	New	Run-of-river
Site ID 50	Tasman-Nelson	6.5	42	New	Run-of-river

Source: MBIE[14]

RENEWABLE ENERGY POLICY

Several key policy measures have shaped the renewable energy landscape in New Zealand. The National Policy Statement for Renewable Electricity Generation, in force since 2011, guides local authorities on how renewable energy sources can be integrated into local planning documents. In 2018, a ban on new offshore oil and gas exploration was introduced. Climate Change Response (Zero Carbon) Amendment Act of November 2019, or the Zero Carbon Legislation, officially put into code the commitment to net zero emissions by 2050. In 2018, an independent review of the country's electricity market (Electricity Price Review) recommended better integration of independent generators, aggregators of storage and controllable demand into the spot market. The Government has taken measures to implement these recommendations.[20]

The Government intends to decarbonize the economy as rapidly as possible and effectively eliminate fossil fuels from electricity generation, electrifying transport and reducing methane emissions from agriculture. In 2019, it published a report from the Interim Climate Change Committee (ICCC) advocating massive changes to the industry, transport and the economy over a short timescale.[21] ICCC has proposed an electrification policy that makes maximum use of electricity in transport and industry, which would allow reducing emissions of carbon dioxide at a substantially lower cost than eliminating fossil fuel generation altogether. However, this would require a large-scale increase in renewable energy generating capacity. The report has been met with criticism, due to the negligible impact of the emissions of New Zealand's emissions on the changing climate as well as the opinion that some changes proposed in the report could increase net worldwide emissions. Overall, some energy sector actors doubt whether the Government's objective can be achieved within the timeframe and at an acceptable cost and many experienced engineers believe that the proposals do not take sufficient account of the engineering challenges that they pose.

Furthermore, it is predicted that in the next few years there will not be enough reserve capacity to avoid blackouts and high prices in a dry hydrological year. It is not clear where the generation needed for the predicted load increase will come from. The risk of blackouts in a dry year is exacerbated by a ban on new gas exploration imposed by the Coalition Government. At the same time, as the ICCC report points out, the Resource Management Act (RMA) of New Zealand makes it extremely difficult to build new power plants.[22] Although it started off with the intention of establishing a reasonable trade-off between development and the environment, recent legal rulings appear to ban any development whose environmental effects cannot be avoided.

The need to obtain environmental approvals is a major hurdle to power project development that needs to be overcome by those proposing new generation. SHP developers are particularly affected because even a small plant can be very difficult and expensive to get through the environmental process. The risk of Government intervention also exists, which was highlighted a few years ago when a minister cancelled an SHP project that had obtained all its environmental approvals.[23] The RMA demands that developers provide virtually complete final designs before an application will be considered.[24] If, after approval is granted, it transpires that major changes are needed to the design, there is a risk that the whole environmental approval process will have to restart. The report concludes that major changes to the RMA are needed if the electrification policy is to proceed.

There are no direct subsidies for renewable energy generation. The Government under Jacinda Ardern has established a US$ 100 million Green Investment Fund (launched in 2018), a US$ 27 million National New Energy Development Centre (launched in 2020) and multiple renewable energy investments through the US$ 3 billion Provincial Growth Fund.[25] The costs imposed on the power system resulting from the intermittent and unpredictable generation from wind and solar power are carried by the consumers, rather than the owners of the power plants. Additionally, SHP projects can be eligible for Avoided Cost of Transmission (ACOT) payments. Finally, the New Zealand Emissions Trading Scheme has been a key driver in renewable energy investments, obliging thermal power generators to purchase and surrender emissions units to match the emissions of the plant, with these units increasing in cost over time.[24]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

There are no special inducements for SHP. However, if recent high electricity prices continue, a number of potential SHP projects are likely to become economic. There are no special grants available for SHP projects.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

A number of computer modelling exercises have indicated that climate change will have an effect on rainfall patterns, although these effects are likely to take hold in the latter part of the century.[26,27] According to simulations produced by the TopNet hydrological model, annual lake inflows will increase. However, a degree of seasonal variation will be introduced, resulting in increased flows in winter and early spring and decreased summer flows as a result of increasing temperatures and greater winter rain with less snowfall. The model shows that overall hydropower generation could increase as a result of these increased flows, with electricity demand being met in winter and spring yet revealing potential shortfalls in the summer and autumn months. Flood and drought risk can also increase for several downstream locations.[28]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In New Zealand, the SHP sector contributes 147 MW of installed capacity (475 MW if plants ≤ 50 MW are considered). It is in a healthy situation and its biggest challenge is restrictive environmental legislation, which makes obtaining environmental approvals extremely difficult.[29]

The main enabler is the current high electricity prices resulting from a ban on gas exploration and low rainfall in hydropower catchments.[30,31] New Zealand also has a number of financing options for renewable sources, which SHP projects can benefit from.

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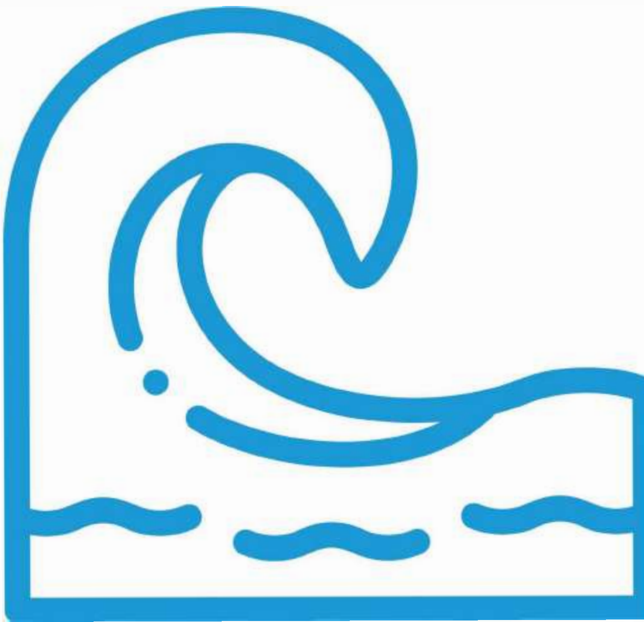


5.2. Pacific Island Countries and Territories

Countries: Fiji, French Polynesia, Federated States of Micronesia, New Caledonia, Papua New Guinea, Samoa, Solomon Islands, Vanuatu

INTRODUCTION TO THE REGION

The national electricity sectors of the Pacific Island Countries and Territories (PICTs) are characterized by a high degree of geographical fragmentation, including the fragmentary nature of major electricity grids as well as the prevalence of micro-grids and off-grid generation. Despite this, management of the electricity sectors is centralized across most of the countries in the region included in the present Report, with public utilities and state-owned companies operating the major grids and generating capacities in Fiji, French Polynesia, New Caledonia, Papua New Guinea, Samoa and Solomon Islands. Vanuatu and the Federated States of Micronesia (FS of Micronesia) are exceptions to this pattern. In Vanuatu, the national grid is managed by two private companies, while in the FS of Micronesia the sector is split between four public utilities companies based on the four federal divisions of the country. Although electricity access is generally high throughout the region, difficult geography complicates extending full electricity access in some countries, particularly in Vanuatu and Papua New Guinea. The FS of Micronesia, New Caledonia, Solomon Islands and Vanuatu are heavily dependent on fossil fuels for electricity generation, while the energy mixes of other PICTs nations are fairly diversified, with renewable energy sources (RES) playing an increasingly important role. Alongside hydropower and solar power, generation from biomass is common in the region, while Papua New Guinea is actively developing geothermal power.

Hydropower is a major energy source across most of the PICTs region. In Fiji and Papua New Guinea, hydropower is one of the leading sources of electricity generation, although installed capacities of thermal power are higher in both countries. In French Polynesia, New Caledonia and Samoa, hydropower forms a significant share of total generation but plays a supplementary role overall. In the FS of Micronesia, Solomon Islands and Vanuatu, the contribution of hydropower to generation is relatively minor.

An overview of the electricity sectors of the countries in the PICTs region is provided in Table 1.

Table 1. **Overview of the Pacific Island Countries and Territories**

Country	Total population (million people)	Electricity access, total (%)	Electricity access, rural (%)	Total installed capacity (MW)	Electricity generation (GWh/year)	Hydropower installed capacity (MW)	Hydropower generation (GWh/year)
Fiji	1	96	94	366	1,061	128	559
French Polynesia	0.3	100	100	300	694	49	160
FS of Micronesia	0.1	83	79	29	64	1	1
New Caledonia	0.3	100	100	1,022	3,233	78	305
Papua New Guinea	9	60	57	1,084	2,087	258	877
Samoa	0.2	100	100	62	171	16	55
Solomon Islands	0.7	73	72	68	98	0.4	1
Vanuatu	0.3	67	58	33	82	1	N/A
Total	**-**	**-**	**-**	**2,964**	**-**	**531**	**-**

Source: *WSHPDR 2022*[1]

Note: Data in the table are based on data contained in individual country chapters of the *WSHPDR 2022*; years may vary.

REGIONAL SMALL HYDROPOWER OVERVIEW

The majority of countries in the PICTS region, including Fiji, FS of Micronesia, Samoa, Solomon Islands and Vanuatu, do not have an official definition of small hydropower (SHP). In French Polynesia, New Caledonia and Papua New Guinea, SHP is defined as hydropower plants with an installed capacity of up to 10 MW.

A comparison of installed and potential SHP capacities in the PICTs region is provided in Table 2.

Table 2. **Small Hydropower Capacities by Country in the Pacific Island Countries and Territories Region (MW)**

Country	Local SHP definition	Installed capacity (local def.)	Potential capacity (local def.)	Installed capacity (≤10 MW)	Potential capacity (≤10 MW)
Fiji	Up to 10 MW	11.3	43.2	11.3	43.2
French Polynesia	Up to 10 MW	48.6	98.0	48.6	98.0
FS of Micronesia	N/A	N/A	N/A	0.7	9.0
New Caledonia	Up to 10 MW	13.0	100.0	13.0	100.0
Papua New Guinea	Up to 10 MW	41.0	153.0	41.0	153.0
Samoa	N/A	N/A	N/A	15.5	22.0
Solomon Islands	N/A	N/A	N/A	0.4	11.0
Vanuatu	N/A	N/A	N/A	1.3	5.4
Total	**-**	**-**	**-**	**131.8**	**441.6**

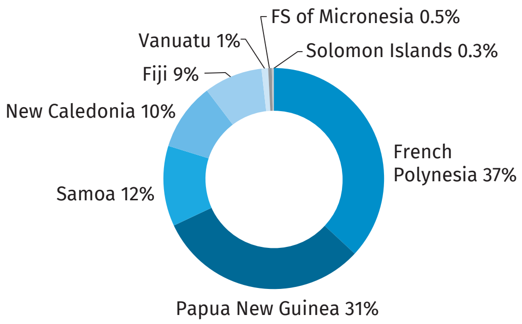
Source: *WSHPDR 2022*[1]

The installed capacity of SHP up to 10 MW in the PICTs region is 131.8 MW, while the potential capacity is estimated at 441.6 MW. Relative to the *World Small Hydropower Development Report (WHSPDR) 2019*, the installed capacity has increased by nearly 15 per cent due to the commissioning of several new SHP plants across the region, with Papua New Guinea accounting for the largest share of the increase. In other countries of the region, installed SHP capacity has seen moderate increases or remained the same. The potential capacity for SHP up to 10 MW has increased by nearly 7 per cent, largely due to a re-evaluation of available data on SHP potential in Fiji.

SHP occupies a significant share of the overall installed hydropower capacity in the PICTs region, accounting for 100 per cent of all hydropower capacity in French Polynesia, the FS of Micronesia, Samoa, Solomon Islands and Vanuatu. This tendency is explained in part by the relatively small overall size of the electricity sector in many countries of the region, but also by specific characteristics of local geography that limit large hydropower development, including the absence of major rivers on smaller islands. Along with other RES, SHP provides additional advantages to island countries as a source of localized electricity generation not requiring the extension and maintenance of centralized grids, as well as a hedge against fluctuations in global fossil fuel prices to which island economies are particularly vulnerable. At the same time, SHP development in the PICTs is constrained by a number of factors common to the region, including geological conditions and the vulnerability of available water resources to climate change. There is also significant opposition to hydropower development from environmental groups and local communities, in part due to the important role of tourism in the region's economy.

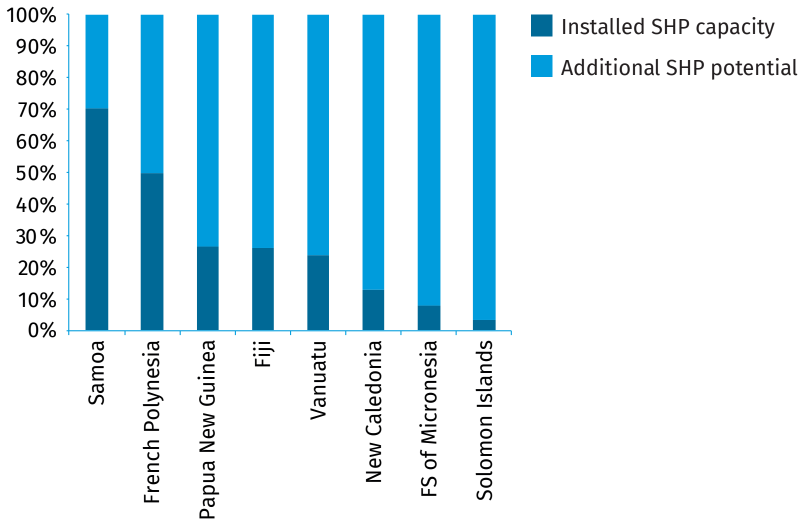
The share of regional installed capacity for SHP up to 10 MW by country is displayed in Figure 1, while the share of total SHP potential utilized by the countries is displayed in Figure 2.

Figure 1. **Share of Regional Installed Capacity of Small Hydropower up to 10 MW by Country in The Pacific Island Countries and Territories Region (%)**



Source: *WSHPDR 2022*[1]

Figure 2. **Utilized Small Hydropower Potential up to 10 MW by Country in The Pacific Island Countries and Territories Region (%)**



Source: *WSHPDR 2022*[1]

The total installed capacity for SHP up to 10 MW in **Fiji** was 11.3 MW in 2021, while potential capacity is estimated at 43.2 MW, indicating that 26 per cent has been developed. Little development of SHP has taken place in the country in recent years, with the last new plant commissioned in 2017 and ongoing projects focusing on the refurbishment of existing plants rather than the construction of new ones.

In **French Polynesia**, there are 16 SHP plants up to 10 MW with a total installed capacity of 48.6 MW. The potential capacity is estimated at 98 MW, indicating that French Polynesia has utilized approximately 50 per cent of its SHP potential. Although the country's SHP capacity has seen only slight increases over the last decade, the Hydromax Project, a 2018 government initiative to promote sustainable hydropower development, has led to the construction of a new SHP plant as well as upgrades to two previously-existing SHP plants.

The FS of Micronesia have 0.7 MW of installed capacity for SHP up to 10 MW, while the potential capacity is estimated at 9.0 MW, indicating that approximately 8 per cent has been developed. The country's installed SHP capacity has remained constant over the last decade. Most hydropower potential in the country is located in the state of Pohnpei, which also hosts the country's only SHP plant. The FS of Micronesia are building a new 2.5 MW SHP plant on the Lehnmesi River, scheduled to be completed by 2023.

In **New Caledonia**, the installed capacity of SHP up to 10 MW was approximately 13 MW at the end of 2020, while the potential capacity is estimated at approximately 100 MW. This indicates that 13 per cent of the known SHP potential has been developed so far. Recent developments in the SHP sector have included the completion of the 3 MW Paalo plant, the first new SHP plant in the country in three decades.

Papua New Guinea has 41 MW of installed capacity for SHP up to 10 MW, while the potential is estimated at 153 MW, indicating that approximately 27 per cent of existing SHP capacity has been developed. With the launch of two new SHP plants, the number of existing SHP plants in PNG had reached 11 as of 2020. Under the Town Electrification Investment Programme, Papua New Guinea is planning to rehabilitate and increase the capacity of some of its existing SHP plants. Ongoing SHP projects in the country include the 3 MW Ramazon plant scheduled to be completed by 2023 and another 10 MW project undergoing feasibility studies.

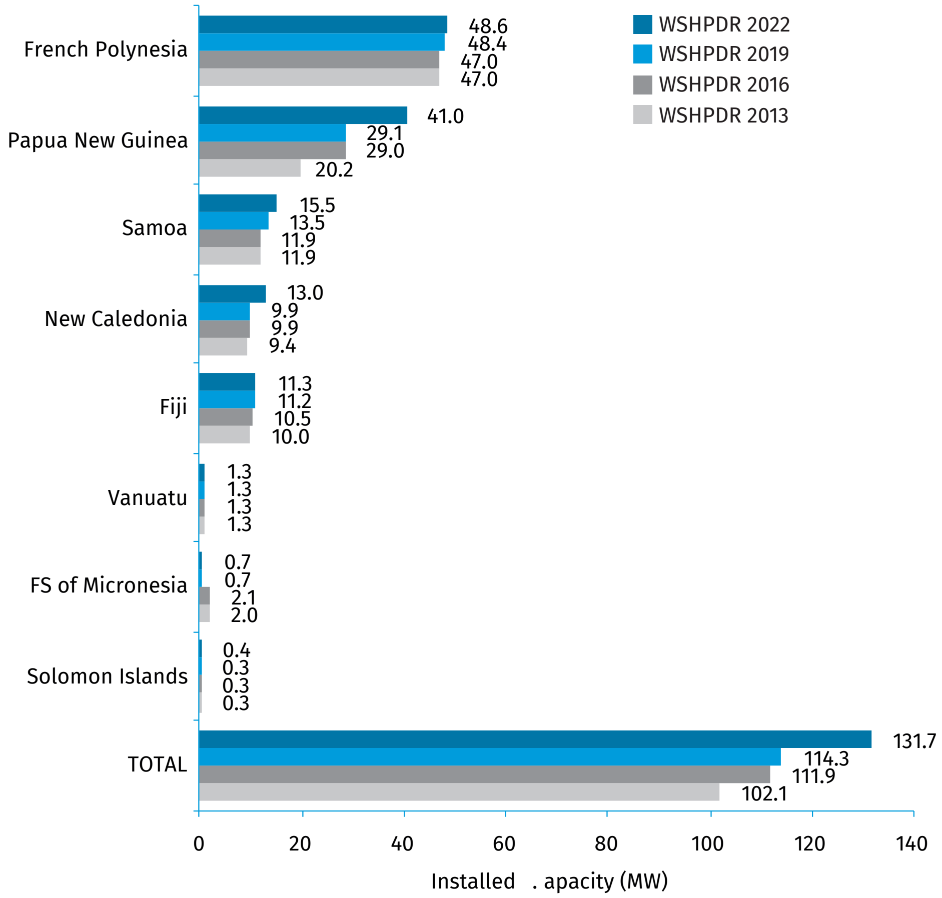
In **Samoa**, the installed capacity for SHP up to 10 MW is 15.5 MW, and the total potential capacity is estimated at 22 MW, indicating that approximately 71 per cent has been developed. SHP plants once supplied more than 85 per cent of the country's electricity, but the share of SHP in the country's energy mix has declined in parallel with growing electricity demand. In recent years, the Renewable Energy Development and Power Sector Rehabilitation Project, funded by multiple governments and international organizations, helped rehabilitate and reconnect 4.69 MW of SHP capacity to the grid. Despite the high financial costs incurred during the rehabilitation process, hydropower remains the most cost-effective source of electricity generation in Samoa.

In **Solomon Islands**, the installed capacity of SHP plants is 361 kW, whereas the potential capacity is estimated at 11 MW, indicating that approximately 3 per cent has been developed. There are 13 hydropower plants in the country, with capacities up to 150 kW. A number of SHP projects, including the 30 kW Beulah micro-hydropower plant, are under development or in the planning stages.

The installed capacity for SHP up to 10 MW in **Vanuatu** is 1.3 MW and the potential capacity is estimated at 5.4 MW, indicating that approximately 24 per cent has been developed. There are existing plans in the country to construct 13 new micro-hydropower plants with a total capacity of 1.5 MW. However, any potential SHP sites in Vanuatu require multi-year monitoring prior to construction to adequately assess both the hydropower potential of the site as well as the risk of flood damage.

Changes in the installed capacities for SHP up to 10 MW of countries in the PICTs region compared to the previous editions of the *WSHPDR* are displayed in Figure 3.

Figure 3. **Change in Installed Capacity of Small Hydropower up to 10 MW from *WSHPDR 2013* to *WSHPDR 2022* by Country in The Pacific Island Countries and Territories Region (MW)**



Source: *WSHPDR 2022*,[1] *WSHPDR 2013*,[2] *WSHPDR 2016*,[3] *WSHPDR 2019*[4]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

While there is significant undeveloped SHP potential in **Fiji**, one of the key challenges for SHP development in the country has been sourcing finance for projects, particularly for smaller developers, as the SHP sector in Fiji is heavily dependent on international financing. Land disputes with property owners are another important barrier, particularly when construction impacts multiple land holdings. On the other hand, Fiji benefits from a strong tradition of hydropower development and the Government has demonstrated commitment to the development of RES, including hybrid plants combining hydropower with other RES.

Barriers to SHP development in **French Polynesia** include competition with the local tourism economy and limitations on construction in protected areas. Enablers include significant untapped SHP potential, the commitment of the Government to energy transition and easier access to financing from France due to the status of French Polynesia as an overseas collectivity of France and the Government's ongoing partnership with the French Development Agency.

In **the FS of Micronesia**, barriers to SHP development include competition between water users for access to freshwater resources as well as the need for technical and financial assistance. At the same time, much of the country's SHP potential remains untapped and SHP can offer a solution for the extension of electricity access to remote off-grid communities.

In **New Caledonia**, major barriers to SHP development include a lengthy preparatory and bureaucratic process for SHP projects, environmental constraints and difficulties in utilizing land within protected areas. The main enabler for SHP development in the future is the Government's plan for a significant enlargement of hydropower capacity, which has already resulted in the construction of one new SHP plant.

In **Papua New Guinea**, barriers to SHP development include high investment costs, insufficient geological and hydrological data and high sediment load in the country's rivers. At the same time, the National Energy Policy for the years 2017–2027 prioritizes ongoing hydropower development and the country's considerable undeveloped SHP potential offers extensive opportunities for future projects. SHP in Papua New Guinea additionally enjoys access to funding from a variety of sources.

Barriers to SHP development in **Samoa** include lack of monitoring data on water resource potential, low accuracy and reliability of project data, decreasing load factors of SHP plants due to climate change and consequent water scarcity, the difficulty of repairing plants in case of damage and local resistance to the construction of SHP plants. Enablers include the available undeveloped potential, policy focus on RES development, availability of funding and incentives in the form of feed-in tariffs (FITs) and local experience in SHP development and rehabilitation.

In **Solomon Islands**, a key obstacle to SHP development is the lack of a standardized acquisition process for land for SHP projects. Additional obstacles include the lack of incentives for investment in SHP as well as technical challenges posed by geological conditions. At the same time, the SHP potential of Solomon Islands remains mostly untapped and the country benefits from the availability of funding for SHP projects from a variety of sources.

In **Vanuatu**, barriers to SHP development include the lack of appropriate sites near population centres, the complexity of electricity transmission and transportation of materials across a multitude of small islands, the high costs of feasibility studies, limited technical expertise and the lack of technical standards for SHP. At the same time, the need for extending full electricity access through micro-grids and off-grid generation contributes to interest in future SHP development in the country and could be financed through climate change-related funds provided by international aid agencies and private entities.

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Fiji

Atul Raturi, the University of the South Pacific and Ravita D. Prasad, Fiji National University

KEY FACTS

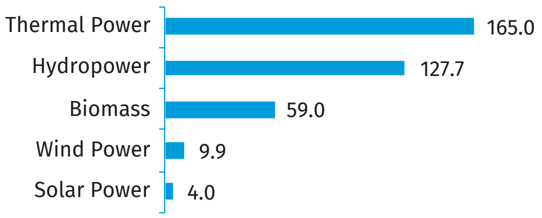
Population	902,906 (2021)[1]
Area	18,270 km^2 [2]
Topography	Fiji is a small island nation with 322 islands, out of which 100 are inhabited. The larger islands are volcanic in origin, while smaller uninhabited islands are mainly coral islands. The largest island is Viti Levu and the second largest island is Vanua Levu. The highest point in Fiji is Mount Tomanivi which is 1,324 metres above sea level.[2]
Climate	Fiji experiences two main climates. The summer months are from November to April, with an average temperature of 30°C during the day and remaining above 20°C at night. The period from November to April is usually wet and hot with possibilities of tropical cyclones. During the winter months from May to October, the climate is marginally drier and cooler, with temperatures dropping by only 2 4°C compared to the summer months.[3]
Climate Change	Climate change is a reality in Fiji, with the Fiji Meteorological Services reporting higher temperature recordings in the last decade (2011–2019). Fiji has also been experiencing more intense tropical cyclones and severe flash flooding in recent years. Coastal erosion and seawater intrusion due to sea level rise (approximately a 6 mm increase per year) has forced many communities to relocate to higher grounds.[4,5]
Rain Pattern	From October to May, Fiji receives significantly higher precipitation compared to the months of June to September. The cyclone season in Fiji is from November to April and corresponds to high rainfall. The average annual rainfall between 1981 and 2017 was 1,981 mm. However, the rainfall is not equally distributed over space and time, resulting in frequent draughts and floods.[6]
Hydrology	On Viti Levu, the main river systems are the Rewa, Navua, Sigatoka and Ba. The Rewa is navigable for 113 kilometres, while in some parts of interior Viti Levu, the Sigatoka provides the main means of transport.[7]

ELECTRICITY SECTOR OVERVIEW

There are two types of electricity generation systems in Fiji: grid-connected and off-grid. The sole utility compan, Energy Fiji Ltd. (EFL), operates the grids in the three largest islands. Independent power producers (IPPs) provide electricity supply to the national grid using biomass. There are grid-connected solar photovoltaic (PV) systems (mostly on the rooftops of commercial buildings), making up approximately 4 MW of total installed solar power capacity in 2018.[8] There was a total of 365.6 MW of installed capacity in Fiji in 2018, of which EFL had approximately 302 MW in its generation portfolio. Of the total, 165.0 MW was from industrial diesel oil (IDO) and heavy fuel oil (HFO) generators, 127.7 MW from hydropower and 9.9 MW from wind power (Figure 1).[9] There is also biomass power generation, however, data on installed capacity for 2018 is not available. As of 2017, IPPs had 59 MW of installed capacity of biomass power generation.[10]

Biomass power generation in the country mainly comes from the IPPs Fiji Sugar Corporation (FSC), Tropik Woods Industry Limited (TWIL) and Nabou Green Energy Limited (NGEL). FSC has three mills (Lautoka, Labasa and Ba), with each mill having its own cogeneration plant of 5 MW, 24 MW and 9 MW, respectively. TWIL is a sawmill that produces electricity from its 9 MW power plant.[10] NGEL, commissioned in 2017, uses wood residue and fast-growing Gliricidia Sepium and invasive African Tulips to power its 12 MW biomass power plant.[11]

Figure 1. **Installed Electricity Capacity by Source in Fiji in 2018 (MW)**

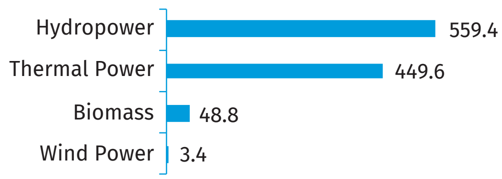


Source: Prasad & Raturi[8] Energy Fiji Limited,[9] Hussain,[10] NGEL[11]

Note: Data for biomass capacity from IPPs are from 2017.

In 2019, 1,061.2 GWh of electricity was supplied to the national grid. Of the total, 559.4 GWh was from hydropower, 449.6 GWh from combusting IDO and HFO, 48.8 GWh came from biomass and 3.4 GWh from wind power (Figure 2).[12]

Figure 2. **Annual Electricity Generation by Source in Fiji in 2019 (GWh)**

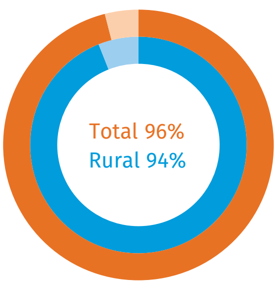


Source: EFL[12]

Note: Grid-connected solar power generation is not considered in the source document.

Off-grid systems provide electricity in remote locations on larger islands and maritime islands where EFL grids cannot reach. Sources for off-grid electricity generation are diesel generators, solar power home systems, micro-grid solar/diesel/battery hybrid and pico- or mini-hydropower systems. The Fiji Department of Energy (DoE) under the Rural Electrification Policy is responsible for ensuring that non-grid connected communities and households have access to some form of electricity.[13] According to the 2017 census, almost 78.5 per cent of the households are connected to the national grid, while almost 17.5 per cent of households have access to off-grid electricity (Figure 3). The remaining 4 per cent of the total Fijian households do not have access to electricity, which comprises 6 per cent of rural households and 2 per cent of urban households.[13] For the villages that are using diesel generators, electricity is only available for 3–4 hours in the evenings.

Figure 3. **Electrification Rate in Fiji in 2017 (%)**



Source: FBoS[13]

Four villages (Namara, Tukavesi, Solevu and Nakoro) in Fiji have solar/diesel/battery hybrid systems. As for diesel generators, there are some sites that have a stand-alone diesel generator, while other sites have hybrid diesel generators with a solar home system or a diesel generator with access to the EFL grid. For sites only with operational diesel generators: Western division has 90.5 kVA in total, Northern Division has 876.5 kVA, Eastern division has 1,326.5 kVA and Central division has 129 kVA. From 2008 to 2019, 13,776 solar home systems (SHS) were installed in remote areas in Fiji.[14]

According to the 2016 Rural Electrification Policy, the Government will pay for the capital cost of rural electrification projects.[15] Three years after commissioning, the off-grid electrification projects is handed over to the community members once they are trained in operation and maintenance. Minor maintenance cost is borne by the community. However, in case of major maintenance work, the responsibility lies with the DoE. The village is responsible for paying for their fuel usage from off-grid diesel generation.

The DoE through its Rural Electrification Unit is responsible for liaising with rural communities concerning their electricity needs and supplying electricity in the form of solar home systems, hybrid systems, small hydropower (SHP) and diesel generators. The grid electricity is supplied by EFL. It is a limited liability company where the Government owns 51 per cent of the shares, domestic customers own 5 per cent and the remaining 44 per cent has recently been sold to a Japanese power company.[16] EFL is responsible for the planning, generation, transmission and distribution and retail of grid electricity. It supplies grid-connected electricity to four islands: Viti levu, Vanua Levu, Ovalau and Taveuni, with each island having its own generators and electricity network. None of the islands have an interconnected grid network. Viti Levu has the largest grid network with peak demand of 172 MW and 252 MW of available capacity, of which almost 50 per cent is from renewable sources.[9]

The country's largest hydropower plant (80 MW), located in Viti Levu, receives water from the Nanuku and Wailoa Rivers. A 41.7 MW run-of-river plant is located at the Sigatoka River headwaters. Vanua Levu has two grids (Labasa and Savusavu) where Labasa has 7.6 MW of peak demand and 11.10 MW of available capacity, all of which comes from diesel generators. Meanwhile, Savusavu has 2.3 MW of peak demand and 4.5 MW of available capacity, with 0.8 MW being from hydropower and the rest from diesel generation. Ovalau has 1.8 MW of peak demand and 2.3 MW of available diesel generators, while Taveuni has 0.4 MW of peak demand that is met by 0.7 MW of hydropower and 1.6 MW of diesel generators.[9]

Fiji has a new Electricity Act 2017 which provides power to an independent body to act as a regulator for the electricity sector. The Fijian Competition and Consumer Commission (FCCC) has been given the responsibility of being that regulator. However, due to its technical and capacity constraints, EFL still holds some regulatory responsibility.[17] The FCCC is an independent body; one of its roles is to determine the minimum electricity export tariff to be paid to IPPs as well as the tariff rate customers pay for electricity used. The minimum electricity export tariff is set at 0.3308 FJD/kWh (0.16 USD/kWh) for electricity sold to the national grid if IPPs are generating 24/7/365.[18]

The electricity demand tariff depends on the customer category: domestic, small business tariff (commercial), maximum demand tariff (industrial) and others (primary and secondary schools, places of worship and streetlights).[18] Domestic customers pay either a base rate or a reduced rate if they consume less than 100 kW per month or earn less than or equal to FJD 30,000 (USD 14,754). The commercial tariff is applicable if the maximum demand is less than 75 kW. Industrial customers are charged and categorized based on their maximum demand (Table 1). For primary and secondary schools, the first 200 kWh are subsidized by the Government, paying 0.1285 FJD/kWh (0.063 USD/kWh), and the school pays 0.2116 FJD/kWh (0.10 USD/kWh).[17]

Table 1. **Electricity Tariffs in Fiji**

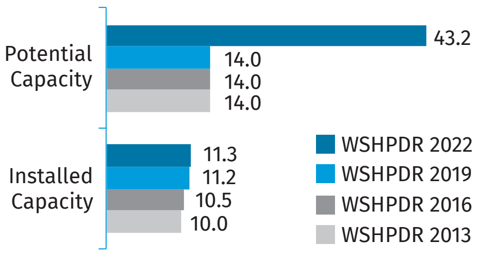
Customer category	*Consumption band*	*Final electricity price (FJD (USD) per kWh)*
Domestic	base rate	0.3401 (0.17)
	< 100 kWh/month	0.1767 (0.087)
Commercial	< 14,999 kWh/month	0.4099 (0.19)
	> 14,999 kWh/month	0.4294 (0.21)
Industrial	75-500 kW in demand	0.2781 (0.14)
	500-1,000kW in demand	0.3026 (0.15)
	> 1,000 kW in demand	0.3270 (0.16)
Other	Places of worship & street lights	0.3401 (0.16)
	Primary and secondary schools	0.2116 (0.10)

Source: Energy Fiji Limited[17]

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of SHP in Fiji. The definition used for this chapter is up to 10 MW. Fiji has grid-connected as well as off-grid SHP plants. The installed capacity of SHP was 11.3 MW in 2021 (Table 2). Since the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity of SHP in the country has changed by 0.1 MW due to a new estimate of the capacity of the Wainikasou plant, while estimates on the economic potential capacity have increased due to access to a new feasibility study based on geospatial analysis and a cost-benefit analysis, revealing 31.9 MW of untapped potential plus the existing capacity, making the total potential 43.2 MW (Figure 4).[12,21,22,23]

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Fiji (MW)**



Source: EFL,[12] *WSHPDR 2013*,[19] *WSHPDR 2016*,[20] WSHPDR 2019,[21] UNFCCC,[22] JICA,[23] DoE,[24] EquatorInitiative[25]

Table 2. **List of Operational Small Hydropower Plants in Fiji**

Name	*Location*	*Capacity (kW)*	*Head (m)*	*Plant type*	*Operator*	*Launch year*
Wainikasou	Viti Levu	6,600	116	Run-of-river	EFL	2004
Vaturu	Viti Levu	3,000	321	Run-of-river	EFL	2006
Wainique	Savusavu	800	–	Run-of-river	EFL	1992
Somosomo	Taveuni	700	590	Run-of-river	EFL	2017
Bukuya	Interior of Ba, Viti Levu	100	–	Run-of-river	Village+ DoE + UNDP	1989
Muana	Vanua Levu	48	–	Run-of-river	Village+ DoE	1999
Kadavu village	Kadavu Island	23	24.6	Run-of-river	Village+ DoE	1994
Nasoquo	Viti Levu	4	–	Run-of-river		1984
Vatukarasa	Viti Levu	3	–	Run-of-river		1993
Buca (under maintenance))	Vanua Levu	0.025	183	Run-of-river	Village + DoE	

Source: EFL,[12] UNFCCC,[22] JICA,[23] DoE,[24] EquatorInitiative[25]

Table 3 shows two plants that were operational previously but currently are awaiting or undergoing maintenance. For the Buca hydropower project, according to the Fiji Department of Energy, there are plans to upgrade its capacity from 25 kW to 125 kW.

Table 3. **List of Ongoing or Planned Small Hydropower Rehabilitation Projects in Fiji**

Name	*Location*	*Capacity (MW)*	*Head (m)*	*Plant type*	*Developer*	*Stage of development*
Nagado/ Vaturu	Viti Levu	2.8	321	Run-of-river	EFL	Restoration works
Buca	Vanua Levu	0.025	183	Run-of-river	Village + DoE	Refurbishment

Source: EFL,[12] DoE[24]

A study by the Japan International Cooperation Agency (JICA) has identified 37 potential hydropower sites.[23] These sites were ranked based on their cost-benefit analysis, environmental impact and technical feasibility, until the list was narrowed down to nine priority sites for investment. Another 2009 report of the DoE has also identified potential SHP sites in Fiji. From the 20 sites selected and ranked for long-term monitoring (2–3 years). The methodology for ranking these plants depended on technical feasibility and economic feasibility, using a supply and demand analysis. As a result of this ranking, six sites were identified as feasible in that study.[26] The sites listed in Table 4 are the nine sites that make up the economic potential used in Figure 4 (31.9 MW). They are ranked in order of priority and are all from the more recent JICA study.

Table 4. **List of Small Hydropower Plants Available for Investment in Fiji**

Name	*Location*	*Potential capacity (MW)*	*Head (m)*	*Type of site (new/ refurbishment)*	*Priority rank*
No. 8 Mba 1U/S	West Viti Levu	9.2	74.7	New	AA
No. 29 Waivaka	South Viti Levu	7.4	176.5	New	AA
No. 14 Naboubuco	Central Viti Levu	2.7	96.9	New	A
No. 24 Nakavika	South Viti Levu	2.6	45.7	New	C
No. 26 Wainavadu	South Viti Levu	2.5	97.04	New	A
No. 28 Waisoi	South Viti Levu	2.1	190.0	New	A
No. 35 Waievu	South Vanua Levu	2.0	76.1	New	AA
No. 31 Saqura	East Vanua Levu	2.0	254.1	New	A
No. 7 Nabiaura	West Viti Levu	1.4	216.9	New	AA

Source: JICA[23]

Grid-connected SHP plants are operated and maintained by the EFL. Off-grid SHP plants are operated and maintained by the DoE for the first three years after commissioning. After three years, the project is handed over to the community after proper training has been done regarding operation and maintenance.

RENEWABLE ENERGY POLICY

The National Development Policy of Fiji aims for 100 per cent of electricity generation to be from renewable sources by 2036, while by 2021, 100 per cent of the population was envisioned to have access to electricity.[27] Fiji is committed to reducing its greenhouse gas (GHG) emissions and thus in the Nationally Determined Contributions (NDC) Implementation Roadmap has set short- and medium-term plans to increase efficiency in the transport and electricity sector and increase the renewable energy share in electricity generation.

The country's NDC target is a 30 per cent reduction in GHG emissions by 2030 when compared to the business-as-usual scenario. Of the 30 per cent, 10 per cent is unconditional, meaning that Fiji is committed to reducing the emissions, while the remaining 20 per cent is conditional on the availability of finance and enabling policies for emissions reduction.[28] Of the 30 per cent reduction in emissions, 20 per cent should come from replacing IDO and HFO generators with renewable energy generation. A further 10 per cent of emissions reduction should come from energy efficiency measures implemented in the electricity demand and transport sector. Similarly, in its Low-Emission Development Strategy (LEDS) 2018–2050, the country shows commitment to reaching net-zero emissions by mid-century.[29]

The National Climate Change Policy 2012 is a document that provides guidelines for different sectors on the impact of climate change and, through planning and implementation programmes, prepares for climate change adaptation and mitigation.[30] Mitigation is to be addressed via assessment and utilization of renewable sources such as hydropower, marine energy, wind power, etc. This document highlights that hydropower will be adversely affected by climate variance, (especially low rainfall) and mentions that deforestation is to be minimized during dam construction. The National Adaptation Plan 2018 supports the SDG 7 Affordable and clean energy for all through its infrastructure section that highlights hydropower and other renewable energy output under new climatic conditions.[31]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

At the time of writing of this chapter, the DoE was investigating potential SHP projects using contour maps from the Lands Department.[32] The DoE undertakes the installation of SHP projects with the assistance of external contractors. EFL approval is only given if required standards have been followed and if the power plant is safe to operate. Before the commencement of any SHP project, an environmental impact assessment (EIA) is carried out and clearance from the Department of Environment is required.

COST OF SMALL HYDROPOWER DEVELOPMENT

The average cost of a grid-connected SHP plant is approximately 3,000 FJD/kW (1,475 USD/kW) and the generation cost (i.e., operations and maintenance cost) is 1.8 FJD/MWh (0.89 USD/MWh).[33] However, the installation of the Somosomo hydropower plant, a joint project between the DoE and the Government of China, cost approximately 30,000 FJD/kW (14,754 USD/kW).[34]

FINANCIAL MECHANISMS FOR SMALL HYDROPOWER PROJECTS

There are no dedicated financial mechanisms for SHP projects in Fiji at the time of writing. Zero duty is charged on import of renewable energy-related equipment. A five-year tax holiday, which provides exemption for all non-VAT taxes, is also available to developers investing in renewable energy generation projects.[35] SHP projects received funding from development project finance in the past.

EFFECTS OF CLIMATE CRISIS ON SMALL HYDROPOWER DEVELOPMENT

Climate change is impacting the rainfall pattern in Fiji. During periods of droughts, there is low output from hydropower plants, while now frequent category five tropical cyclones can damage power infrastructure such as transmission and distribution lines.[5]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Fiji currently has 11.3 MW of SHP installed capacity from operational plants, with an additional 2.8 MW of SHP capacity undergoing maintenance or upgrading and 19.1 MW of planned projects since 2009.[26] There is significant potential, but sourcing finance is always a challenge for smaller utility companies and IPPs.

The following points summarize the main barriers to SHP development in Fiji that have been identified:

- One of the major barriers is the land issue. For SHP projects, a significant land area is needed, from the water source (weir) to the power plant. The path where the pipe(s) are laid out for penstock can cover three to four different mataqali's (traditional land), which makes negotiations with landowners difficult.
- According to the DoE, landowners interpret land agreements differently during the "talanoa" (discussion) sessions between DoE staff and themselves. The DoE suggests that it is best to have the agreement in writing or to use land that does not deal with direct involvement of landowners, i.e., use the native land leased by the Government.
- There is a strong need for enhanced and continuous capacity development of the DoE staff regarding various aspects of SHP development.
- IPPs need access to financing and support from donors and other entities like ADB, UNDP, GEF, GCF, etc.

The following points summarize the main enablers for SHP development that have been identified:

- The ambition of the Government to achieve 100 per cent renewable electricity generation by 2036 and universal access to electricity requires development of new energy resources, including SHP.
- EFL has significant experience in developing and operating hydropower projects over the past four decades. It is well-placed to increase the renewable energy component in its grid by investing into new SHP projects.
- There is also potential to develop pumped-storage hydropower plants, which can be run in combination with solar/wind power plants.

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French Polynesia

Davy Rutajoga, International Center on Small Hydro Power (ICSHP)

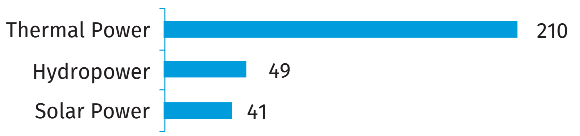
KEY FACTS

Population	282,534 (2020)[1]
Area	4,167 km^2 [2]
Topography	The archipelagos of French Polynesia are the Tuamotu Archipelago, Society Islands, Marquesas Islands, Tubuai Islands and Gambier Islands. The Society Islands account for two fifths of the total land area and are the most westerly. Resulting from the emergence of underwater volcanoes, the islands are made of eroded volcanic cones that cut up into high volcanic peaks and deep valleys. The highest peak is Mount Orohena, culminating at 2,241 metres.[3]
Climate	The climate in French Polynesia is tropical, warm and humid. The cool and dry season lasts from May to October with some variations from island to island. In Papeete, the average annual temperature is 26°C with an average high of 33°C in March and an average low of 21°C in October. In the southern Tubuai Islands, the climate is cooler with an average annual low temperature of 18°C. Humidity is high all year long.[3]
Climate Change	The islands of French Polynesia are affected by global warming. Sea level rise, increased erosions, rainfall irregularities and frequent extreme climatic events have been observed. The average annual temperature has increased by 1.1°C since the 1950s and is expected to increase further. Sea level rise is of great concern in French Polynesia, with levels projected to rise by 80 centimetres by the year 2100.[4,5]
Rain Pattern	French Polynesia experiences a warm and rainy season from November to April, with December being the wettest month. Precipitation is abundant on most islands, with the exception of northern Tuamotu and the Marquesas Islands. Coastal areas experience an average rainfall of 3,050 mm.[3]
Hydrology	Water resources are abundant and groundwater is used extensively, though availability varies according to the topography of the island. They are abundant in highly elevated islands and limited on the atolls.[6]

ELECTRICITY SECTOR OVERVIEW

The main sources of electricity in French Polynesia are thermal power and hydropower, accounting for 71 per cent and 23 per cent, respectively, of the total electricity generation, which amounted to 694 GWh in 2019. Solar power generation amounted to 40 GWh, or 6 per cent of the total generation in the same year (Figure 1).[7]

Figure 1. **Annual Electricity Generation by Source in French Polynesia in 2019 (GWh)**

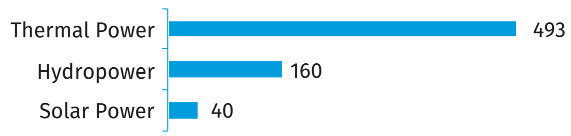


Source: IRENA[7]

French Polynesia is dependent on non-renewable thermal energy for most of its electricity needs. However, plans have been formulated by the Government to transition to renewable energy, with a set goal of a 75 per cent share of renewable energy in the generation mix by 2030.[8]

´In 2020, French Polynesia had 300 MW of installed electricity capacity, of which thermal power and hydropower represented 70 per cent and 16 per cent, respectively. Solar power accounted for 41 MW, or 14 per cent, of the total installed capacity (Figure 2).[7]

Figure 2. **Installed Electricity Capacity by Source in French Polynesia in 2020 (MW)**



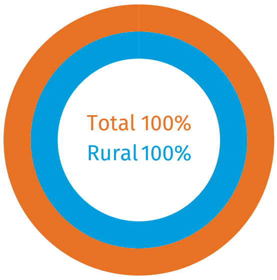
Source: IRENA[7]

As French Polynesia is composed of multiple islands, the production and consumption of electricity varies depending on the population, remoteness and installation of plants. The main electricity utility company in the islands is the Electricité de Tahiti (EDT ENGIE) and its subsidiary Marama Nui, which operates hydropower plants in Tahiti and the

Marquises. As French Polynesia is an overseas collectivity of France, EDT ENGIE is connected to the French multinational utility company ENGIE, which promises to help bring about the development of clean energy in the islands.[9]

In 2020, 100 per cent of the rural and urban population of French Polynesia had access to electricity (Figure 3).[10]

Figure 3. **Electrification Rate in French Polynesia in 2020 (%)**



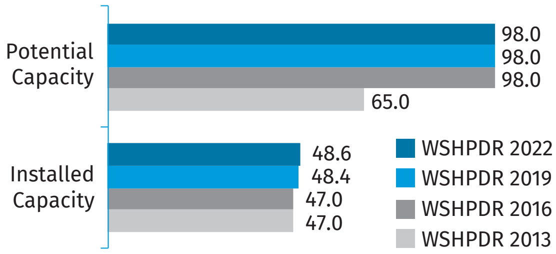
Source: World Bank[10]

Electricity tariffs in French Polynesia in 2019 were between 0.17 USD/kWh for low consumption and 0.37 USD/kWh for high consumption.[11]

SMALL HYDROPOWER SECTOR OVERVIEW

French Polynesia defines small hydropower (SHP) as hydropower plants that have an installed capacity of up to 10 MW. There are currently 22 operational SHP plants in French Polynesia with a total installed capacity of 48.6 MW (Table 1), a 0.2 MW increase from the installed capacity reported in the *World Small Hydropower Development Report (WSHPDR) 2019*. This increase is due to the construction of a 220 kW SHP plant in Maroto as part of the Hydromax Project, a 2018 project that aimed to optimize hydropower without any negative impact on the environment.[12,13] The estimated SHP potential in French Polynesia is 98 MW, similar to the estimates in the *WSHPDR 2019* (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in French Polynesia (MW)**



Source: EGT ENGIE,[12] *WSHPDR 2019*,[13] *WSHPDR 2013*,[14] *WSHPDR 2016*[15]

There are 16 SHP plants in Tahiti, distributed across five valleys: Vaihiria, Vaite, Faatautia, Titaaviri and Papenoo. The Papenoo valley alone accounts for 60 per cent of the total hydropower production in Tahiti. There are a further six SHP plants in the Marquesas Islands found in Hiva Oa and Nuku Hiva.[12]

Table 1. **List of Existing Small Hydropower Plants in French Polynesia**

Name	*Locations*	*Capacity (MW)*
Papenoo	Tahiti	28.4
Faatautia	Tahiti	7.5
Vaihiria	Tahiti	4.9
Titaaviri	Tahiti	4.1
Vaite	Tahiti	2.5
Hiva Oa and Nuku Hiva	Marquesas Islands	1.2
Total		**48.6**

Sources: EGT ENGIE,[12] High Commission of the Republic in French Polynesia[16]

RENEWABLE ENERGY POLICY

Although French Polynesia is an overseas collectivity of France and is thus led by France in most areas, it is autonomous on matters of handling climate change and formulating mitigation and adaptation strategies. This includes renewable energy policies and programmes.

In 2015, the Government of French Polynesia launched the Energy Transition Plan (ETP) and set a target of increasing the share of renewable energy in the islands' generation mix to 75 per cent by 2030. In order to achieve this goal, the Hydromax Project was developed. This project aimed to increase the generating power of hydropower plants, while minimizing negative environmental impact. As part of the Hydromax Project, a new SHP plant was constructed as well as the capacity of the SHP plants in Titaaviri and Papenoo was increased. The ETP is supported by the French Development Agency (AFD), which is providing a funding of USD 450,000.[8,16,17]

In 2019, the Energy Code of French Polynesia was updated to include a ban on the construction of new fossil fuel-powered plants or any non-renewable power plants. It also stipulates that no refurbishments of non-renewable energy power plants can be funded by the Government. Funding can only be given towards the construction or refurbishment of renewable energy power plants.[18]

French Polynesia is a member of the Pacific Centre for Renewable Energy and Energy Efficiency (PCREEE) and as such is committed to the improvement of access to modern, affordable and reliable energy services, energy security and mitigation of negative externalities of the energy system by promoting renewable energy and energy efficiency investments, markets and industries.[19]

SMALL HYDROPOWER LEGISLATION AND REGULATIONS

The main legislation and regulation documents in French Polynesia concerning hydropower projects are:

- The Energy Code of French Polynesia (Country Law No. 2019-27 of 2019);
- Law No. 2013-27 of 2013 on the Guiding Principles of the Energy Policy of French Polynesia.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

In general, SHP provides a sound contribution to French Polynesian society. The development of new SHP projects is hampered mainly by:

- Most water resources, including waterfalls, are highly touristic, which is the backbone of the economy. The construction of dams and hydropower plants in the vicinity of these sites could potentially deter tourists from visiting;
- Many of the valleys with hydropower potential are often inhabited by protected species and contain archaeological sites.

Enablers for SHP development in French Polynesia include:

- Untapped SHP potential that presents opportunities for development;
- The Energy Transition Plan (ETP), which considers hydropower development a priority;
- The Government is committed to the development of renewable energy, notably through its membership in the PCREEE;
- Partnership with AFD would be beneficial as France manufactures hydropower plant equipment;
- High financing potential as French Polynesia is a collectivity of France and thus could benefit from the country's internal financing mechanisms for development projects.

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Federated States of Micronesia

International Center on Small Hydropower (ICSHP)

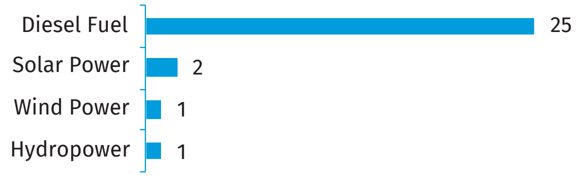
KEY FACTS

Population	116,255 (2021)[1]
Area	702 km^2 [2]
Topography	The 607 islands of the Federated States of Micronesia include mountainous islands of volcanic origin and coral atolls. The country is divided into four states each composing a region of several islands. Kosrae in the east is mostly mountainous with two high peaks, Fenkol (634 metres) and Matanti (583 metres). Just west is Pohnpei that has the highest elevations in the country and the highest peak, Mount Totolom at 791 metres. Chuuk contains 14 significant islands of rugged terrain and several low-lying atolls. Yap is the south-easternmost state with a peak elevation of 178 metres at Mount Tabiwol. The outer islands of all states are mostly coral atolls.[2]
Climate	The Federated States of Micronesia has a wet, tropical climate. The average temperature is 27°C and varies little throughout the year. The wet season is long, between April and December, while the dry season is short, during January to March.[3]
Climate Change	As a country of islands, climate change effects such as sea level rise and coastal erosion and flooding are of particular concern. These are already being experienced and expected to accelerate into the coming decades. Additionally, extreme storms such as typhoons are becoming more intense and more frequent. Ocean acidification is also weakening the country's coral reefs and atolls, which serve as barriers to the main islands.[4]
Rain Pattern	Micronesia experiences plentiful precipitation ranging between 3,000 mm per year on some islands and up to 9,000 mm on others. Pohnpei is considered by some as the wettest place in the world with its average annual rainfall at 9,000 mm. Rainfall can happen all year round but is heaviest between April and December. The country is at high risk of typhoons and tropical storms each year around July.[2,4]
Hydrology	Due to having the highest elevations, the state of Pohnpei has the most rivers, approximately 40 of them, which flow all year long. Similarly, in Kosrae, almost all streams and rivers flow all year long, including the Finkol, Innem and Okat. The islands of Chuuk have just a few permanent rivers, including the Wichon and Kiepw. Conversely, the few rivers of Yap tend to stop flowing during the dry season. Outer islands lack streams and rivers, with the only source of fresh water being rain and groundwater.[2,5]

ELECTRICITY SECTOR OVERVIEW

As of 2020, the total installed capacity across the Federated States of Micronesia (FSM) was 29 MW. Of this, diesel fuel accounted for 25 MW (86 per cent), solar power for 2 MW (7 per cent) and the remaining 7 per cent was split between wind power for 1 MW and hydropower for 1 MW (Figure 1).[6] Imported diesel fuel has historically been the most important energy source for the country, although renewable energy has been incorporated within the last few years. Plans to increase the overall installed capacity in the country have been underway with the financial support of international entities. Between 2019 and 2024 there are several ongoing and planned projects with investments amounting to USD 109.50 million from the World Bank, the Asian Development Bank, the European Union, Japan, the United States and the United Nations Development Programme. These projects include numerous solar power projects, both on the national grid and the creation of mini-grids, a few diesel fuel plant projects, one hydropower project and one wind power project.[7]

Figure 1. **Installed Electricity Capacity by Source in the Federated States of Micronesia in 2020 (MW)**



Source: IRENA[6]

In 2019, total electricity generated in the FSM was 64 GWh. Diesel fuel generated 60 GWh (94 per cent), solar power 3 GWh (5 per cent) and hydropower 1 GWh (1 per cent) (Figure

2).[6] Thus, renewable energy accounted for 6 per cent of electricity generation in 2019. According to the country's Energy Master Plan, renewable energy generation goals included 9 per cent by 2018 and 30 per cent by 2020, indicating that actual renewable energy generation fell short of the goals.[7]

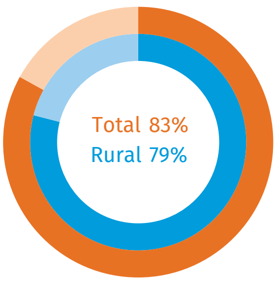
Figure 2. **Annual Electricity Generation by Source in the Federated States of Micronesia in 2019 (MW)**

Source: IRENA[6]

The country consists of four states: Chuuk, Kosrae, Pohnpei and Yap. Each state has their respective publicly-owned utility company: Chuuk Public Utility Corporation (CPUC), Kosrae Utilities Authority (KUA), Pohnpei Utilities Corporation (PUC) and Yap State Public Service Corporation (YSPSC). They are each vertically integrated and the only electricity and water company in their states. The companies are overseen by their respective utility board made up of members appointed by their state governments. All four companies are members of the greater Pacific Power Association that associates all utility companies in the 22 pacific island countries to share technical assistance and expertise amongst them.[8]

The overall electrification rate of Micronesia is 83 per cent, which includes an urban electrification rate of 97 per cent and a 79 per cent rural electrification rate (Figure 3).[9] Rates vary greatly across the four states with Chuuk having the lowest rate, under 30 per cent, while the other three states have rates between approximately 70 and 100 per cent.[10] Electrification of Chuuk is highly prioritized by the state and ongoing projects include installing a number of separate mini-grids in remote areas of several of its islands as well as installing over 500 solar panels on individual homes across the state. The country aims to have universal access to electricity by 2027.[7]

Figure 3. **Electrification Rate in the Federated States of Micronesia in 2020 (%)**



Source: World Bank[9]

Electricity tariffs are proposed by the state utility company and approved by its utility board. Each state has their own tariff rates that are calculated depending on the cost of diesel fuel per gallon with rates varying for different types of users or usage.[11] Current electricity tariff rates in Chuuk, Pohnpei and Yap are detailed in Table 1. Current rates in Kosrae are unavailable.

Table 1. **Electricity Tariffs in the Federated States of Micronesia**

Utility Company	*Type of Consumer*	*Usage*	*Tariff (USD/kWh)*
CPUC	Residential		0.4478
	Commercial		0.4778
	Government		0.4978
PUC		< 7,000 kWh	0.6225
		> 7,000 kWh	0.6225 + USD 9 per kW demand
YSPSC*	Residential	< 50 kWh	0.3712
		50–250 kWh	0.4242
		> 251 kWh	0.4507
	Commercial	< 1,000 kWh	0.4507
		> 1,000 kWh	0.5303
	Government		0.7863

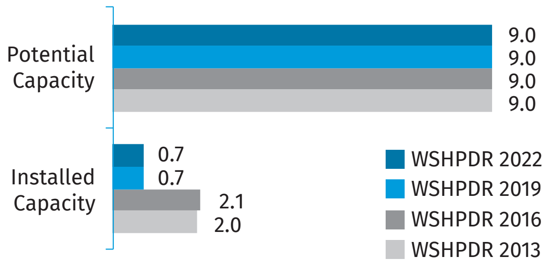
Source: CPUC,[11] PUP,[12] YSPSC[13]

Note: *Values for Yap Island proper, outer island rates differ.

SMALL HYDROPOWER SECTOR OVERVIEW

There is no official definition of small hydropower (SHP) in the FSM, therefore, this chapter uses the standard definition up to 10 MW. The total installed capacity of SHP is 0.725 MW, while the total potential is 9 MW, indicating that approximately 8 per cent of possible SHP has been developed in the country. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, both installed and potential capacities have remained the same (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in the Federated States of Micronesia (MW)**



Sources: World Bank,[10] *WSHPDR 2019*,[5] *WSHPDR 2016*,[14] *WSHPDR 2013*[15]

Due to river properties, the hydropower potential in the country is mostly limited to the state of Pohnpei. The only hydropower plant in the country is the 725 kW Nanpil plant in the state of Pohnpei. This plant was originally built in the 1980s with 2.1 MW, but during a rehabilitation process in 2014, only 725 kW was reinstalled due to the conflicting water demand of the same reservoir.[10] More recently, a site on the Lehnmesi River has been identified for a 2.5 MW SHP project. Within the Renewable Energy Development Project funded by the Asian Development Bank, plans to construct this plant are underway and envisaged to be completed by 2023. The project is valued at approximately USD 2 million.[7]

RENEWABLE ENERGY POLICY

A defined National Energy Policy (NEP-2012) is in place, with each of the four states having specific action plans. In April 2018, the country launched its Energy Master Plan. The NEP-2012 defined the national goal of improving the livelihoods of all citizens with affordable, reliable and environmentally friendly energy. The policy specifically promotes sustainable, social and economic development through the provision and utilization of cost-effective, safe, reliable and sustainable energy services. It set a goal to reach a 30 per cent renewable energy share by 2030.[16]

The NEP-2012 is in line with the objectives of Sustainable Energy for All Initiative (SE4ALL) and Agenda for Change in poverty reduction, sustainable growth, clean energy and improving resilience to natural disasters and climate change. All these development objectives can be achieved and accelerated through reinforced cooperation and partnership between the country and its development partners. The plan highlights the importance of external investments and public-private partnerships in the sector. However, no legal framework or financial incentives, such as feed-in-tariffs, to encourage investment in the electricity sector have been developed as of yet.[16]

The Energy Master Plan of 2018 discusses the expansion of capacities and energy security for the country. It calls for over USD 300 million in investments for the installation of numerous schemes, mostly of solar power, the rehabilitation of the distribution network and bringing electricity to unserved communities, many with the use of mini-grids. The plan foresees a 47 per cent share of renewable energy by 2024 if all projects in the plan were to be implemented before that time. As per reports from the 2022 Research and Development Conference for the Energy Sector, many of these projects are ongoing, but project completions are not clearly announced.[7]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

Barriers to the development of SHP include:

- The country lacks extensive freshwater supply and there is therefore a conflict between water demand and the use of hydropower, as shown in the case of the current Nanpil SHP plant;
- For the development of hydropower, technical and financial assistance is needed, including site-specific hydrology data, funding and site-specific impact assessments covering river flow, land inundation and the general environment.[5]

Enablers for the development of SHP include:

- Most of SHP potential is untapped leaving technical opportunity for development;
- Access to electricity in the country is not universal and SHP development in remote areas can bring electricity to communities that have been without;
- Currently, fossil fuels account for 94 per cent of electricity generation. SHP could be used to achieve the goal of 30 per cent renewable energy by 2030.

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New Caledonia

Bastian Morvan, Department of Industry, Mines and Energy; and International Center on Small Hydro Power (ICSHP)

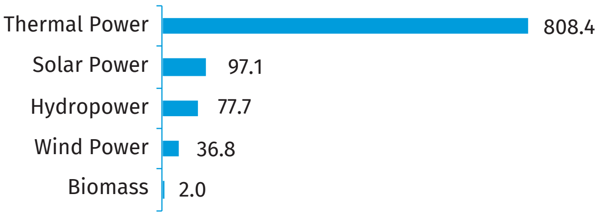
KEY FACTS

Population	271,960 (2020)[1]
Area	19,103 km[2]
Topography	New Caledonia consists of a group of islands: the island of New Caledonia, where the capital Nouméa is located, the Loyalty Islands, the Bélep Islands, the Île des Pins and a number of uninhabited islets. The island of New Caledonia is by far the largest in the country, measuring 50 kilometres in width and 500 kilometres in length. The island's eastern and western halves are separated by rugged mountains that run north-south. Most of the southern third of the island is characterized by a plateau, which rises to 1,617 metres at Mount Humboldt. Mount Panié, the highest peak in New Caledonia, rises to 1,628 metres above sea level and is located in the north-east of the main island.[2]
Climate	The climate is subtropical and is influenced by annual changes in the position of the subtropical high-pressure belt and bass intertropical pressures. There are two main seasons and two inter-seasons: a hot and humid hurricane season (November–April), a transitional season (April–May), a cold season with westerly winds (May–September) and a dry season with constant trade winds (September–November). The average annual temperature ranges between 22°C and 24°C. In the south of the island of New Caledonia, temperatures can exceed 30°C. The lowest temperature recorded in the capital city, Nouméa, is 13°C, while in the north temperatures as low as 5°C have been recorded.[2,3]
Climate Change	Due to the country's topography, the marine environment is most impacted by climate change, with coral reef degradation occurring as a result of successive bleaching events. In 1996, the corals of New Caledonia experienced severe bleaching with the coral mortality rate rising as high as 80 per cent. Rising sea levels also pose a threat to the beaches and coastal ecosystems of New Caledonia as estuaries and low-lying islands are likely to be particularly flooded, especially during tropical storms. Between 1980 and 2099, the air temperature in New Caledonia is expected to increase by 1.8-2.1°C and precipitation is projected to decrease by 5–8 per cent.[4,5]
Rain Pattern	Precipitation happens throughout the year and ranges from less than 1,000 mm on the west coast of the main island to more than 3,000 mm on the east coast. Rainstorms are particularly common on the east coast. There are two particularly rainy periods, from December to March and from July through August. September through November are the driest months.[2]
Hydrology	The longest river in the country is the Diahot, which flows northwards on the main island for approximately 100 kilometres along the western escarpment of the Mount Panié. There are also numerous streams descending from the central mountain chain. They tend to flood rapidly after rainfall and dry out in dry weather.[2]

ELECTRICITY SECTOR OVERVIEW

In 2019, the total installed capacity of New Caledonia was 1,022 MW.[6] Thermal power dominates the country's energy mix, accounting for 79 per cent of total installed capacity in 2019. Solar power is the most developed renewable energy source, accounting for almost 10 per cent of the total installed capacity, followed by hydropower at less than 8 per cent, wind power at less than 4 per cent and biomass at 0.2 per cent (Figure 1).[6]

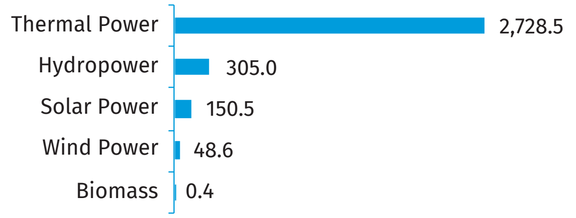
Figure 1. **Installed Electricity Capacity by Source in New Caledonia in 2019 (MW)**



Source: DIMENC[6]

Electricity generation in 2020 reached 3,233 GWh, with 84 per cent coming from thermal power, 9 per cent from hydropower, almost 5 per cent from solar power, 2 per cent from wind power and 0.01 per cent from biomass (Figure 2).[7]

Figure 2. **Annual Electricity Generation by Source in New Caledonia in 2020 (GWh)**



Source: DIMENC[7]

Since 1995, 100 per cent of the population in Caledonia, both in rural and urban areas, have had access to electricity.[8] Electricity consumption in 2020 totalled 3,165.8 GWh, of which only 753.1 GWh (24 per cent) was for public consumption from the grid. The remaining 2,412 GWh (76 per cent) was used by the metallurgical and mining industry.[7] Thus, the electricity sector in New Caledonia is inextricably linked to industry, particularly nickel extraction and processing, providing electricity to the three major nickel plants - Koniambo Nickel SAS, Doniambo of the Société Le Nickel (SLN) and Vale Nouvelle-Calédonie (VNC).[9]

Aside from the metallurgical sector, the electricity sector is made up of the New Caledonian Energy Company (ENERCAL), the country's largest electricity producer, accounting for 50 per cent of electricity production and with 80 per cent produced from renewable energy sources. ENERCAL owns the grid concession and the majority of hydropower plants in the country. The Government has mandated ENERCAL with managing the country's transmission network. It buys electricity from other power producers and transports it to industrial customers or to the distributing companies EEC-Engie and ENERCAL itself.[10]

The transport network belongs to the Government of New Caledonia, which has entrusted its management (operation and maintenance) to ENERCAL.[11] The country has six grids: one on the main island and five on smaller islands. The transmission network in the island of New Caledonia consists of 560 kilometres of 150 kV lines, 650 kilometres of 33 kV lines and 16 substations.[12]

The Department of Industry, Mines and Energy of New Caledonia (DIMENC) is the government agency responsible for the development and enforcement of the regulatory framework for the electricity sector, overseeing electricity prices and executing the technical control of electricity lines in order to ensure a balance between the electricity demand and supply.[13]

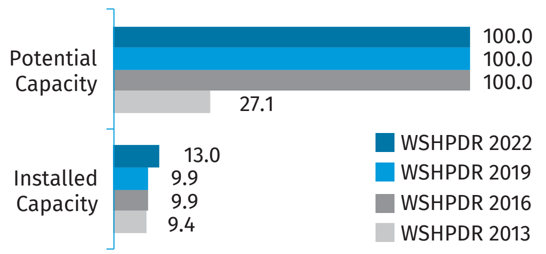
Electricity tariffs are defined on a trimestral basis by the Government and are published in the Official Journal of New Caledonia. The tariff system is uniform across the country, with prices varying depending on the type of consumption. As of January 2022, the electricity tariffs were 31.4 CFP/kWh (0.30 USD/kWh) for residential consumers and 22.01 CFP/kWh (0.21 USD/kWh) for industrial and commercial consumers.[7]

SMALL HYDROPOWER SECTOR OVERVIEW

In New Caledonia, small hydropower (SHP) is defined as hydropower plants with a capacity up to 10 MW. SHP plants are further classified into the categories of pico-hydropower (below 500 kW), micro-hydropower (from 500 kW to 2 MW) and SHP (from 2 MW to 10 MW).[14]

As of the end of 2020, the installed capacity of SHP in New Caledonia was 12.98 MW, while potential capacity is estimated at approximately 100 MW.[15,16,17] Thus, approximately 13 per cent of the known SHP potential has been developed so far. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has increased by 3 MW as a result of the commissioning of the new Paalo plant, whereas the potential estimate has remained unchanged (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in New Caledonia (MW)**



Source: ENERCAL,[15] Government of New Caledonia,[16] *WSHPDR 2016*,[17] *WSHPDR 2013*,[18] *WSHPDR 2019*[19]

As of November 2021, there were 12 hydropower plants in operation in New Caledonia, out of which 11 were SHP plants with installed capacity ranging from 0.02 MW to 7.20 MW (Table 1). Four hydropower plants - Yaté, Néaoua, Thu and Paalo - are connected to the grid. The Yaté hydropower plant, with a capacity of 68 MW, is the only large hydropower plant in New Caledonia. It was commissioned in 1958, has four Francis turbines of 17 MW each and a 40 km^2 reservoir with a storage capacity of 310 million m^3. Approximately 90 per cent of electricity generated by this plant is consumed by the SLN metallurgic plant and only 10 per cent is used for public distribution. The Néaoua SHP plant was launched in 1982, has a reservoir with a capacity of 1.75 million m^3 and two turbines of 3.6 MW each. Electricity generated by the plant is fed into the grid for public consumption. The Thu plant was commissioned in 1990 and is a run-of river plant with one Pelton turbine of 2.2 MW. The most recently commissioned hydropower plant in New Caledonia is the Paalo SHP plant with a capacity of 3 MW, which was launched in December 2020 to supply the entire island of New Caledonia via the island's transport network.[15] Until the commissioning of the Paalo plant the country's SHP capacity remained unchanged for almost three decades.

Table 1. **List of Operational Small Hydropower Plants in New Caledonia**

Name	*Location*	*Installed capacity (MW)*	*Plant type*	*Operator*	*Launch year*
Néaoua	Houaïlou	7.20	Reservoir	ENERCAL	1982
Thu	Houaïlou	2.20	Run-of-river	ENERCAL	1990
Paalo	Pouébo	3.00	Run-of-river	ENERCAL	2020
Borendy	Thio	0.18	Run-of-river	ENERCAL	1987
Ouégalé	Pouébo	0.13	Run-of-river	ENERCAL	1991
Kouaré	Thio	0.08	Run-of-river	ENERCAL	1983
Caavatch	Hienghène	0.05	Run-of-river	ENERCAL	1984
Pouébo (Janisel)	Pouébo	0.05	Run-of-river	ENERCAL	1983
Wadiana	Yaté	0.04	Run-of-river	ENERCAL	1982
Ouaté	Pouembout	0.02	Run-of-river	ENERCAL	1984
Katricoin	Moindou	0.03	Run-of-river	N/A	1983
Total		**12.98**			

Source: ENERCAL,[15] Government of New Caledonia[16]

The remaining eight SHP plants are classified as micro-hydropower and range in capacity from 0.02 MW to 0.18 MW. They are of a run-of-river type and are not connected to the grid, providing electricity to the isolated areas of the main island. In 2020, these eight plants generated 3.7 GWh of electricity, while the larger SHP plants generated 20.2 GWh.[7]

The total potential of SHP in New Caledonia is estimated to be between 100 MW and 250 MW.[17] The Research and Development Institute (IRD) has recommended that the focus in hydropower development in New Caledonia should be made on reservoir plants rather than on run-of-river plants due to the country's relatively steep relief and precipitation patterns.[14,17]

RENEWABLE ENERGY POLICY

Renewable energy is seen as a way to reduce the country's dependency on fossil fuel imports. In 2016, New Caledonia adopted the Energy Transition Plan (Energy Transition Scheme of New Caledonia), which set the following three objectives to be achieved by 2030:

- Decrease primary energy consumption by 20 per cent (including the mining and metallurgical sector) and final energy consumption by 25 per cent (excluding the mining and metallurgical sector);
- Achieve 100 per cent of public electricity consumption from renewable energy as well as 100 per cent of electricity generation on the islands from renewable energy sources;
- Decrease emissions in the residential and tertiary sectors by 35 per cent, in the mining and metallurgical sector by 10 per cent and in the transportation sector by 15 per cent.[20]

The transitional energy mix is expected to keep relying on thermal power for the base load, but also optimize stable renewable energy sources (hydropower, biomass), develop intermittent renewable energy sources (solar and wind power) as well as develop energy storage solutions. Thus, among renewable energy sources, hydropower is planned to see 74 MW of additional capacity by 2030, including 44 MW from reservoir-based hydropower and 30 MW from run-of-river plants. Thus, total hydropower capacity in the country is planned to reach 151.4 MW by 2030.[20,21]

The Energy Transition Plan recognizes that the development of renewable energy sources in New Caledonia requires improving the local technical and economic capacity as well as developing auxiliary services in order to stimulate demand and investment in the renewable energy sector. To support the implementation of this plan, the French Development Agency (AFD) Nouméa, partnered with the Caledonian Energy Agency (ACE) in June 2020 and has so far invested EUR 233 million (USD 264 million) into the energy transition of New Caledonia and completed several renewable energy projects as well as supported actions carried out by local communities.[22]

Another measure covered in the plan is the decentralization of electricity production and the promotion of self-generation.[9] Since 2016, four government orders have allowed self-generation from solar power for household, professional and community use. The objective is to encourage self-consumption, with possible resale of the surplus at a price of 15 CFP/kWh (0.14 USD/kWh). [23]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The major barriers to SHP development in New Caledonia include:

- Projects take a long time to develop, requiring numerous environmental studies and permits;
- Environmental constraints increase production costs;
- Protection by law of indigenous lands, which represent most of the land of New Caledonia and where acquisition of land and water rights is not allowed.

The key existing enabler for SHP development in New Caledonia is the Government's prioritization of the development of renewable energy sources, including hydropower. By 2030, installed hydropower capacity is projected to double, reaching a total of 151.4 MW, including 39.4 MW of run-of-river hydropower. The Government of New Caledonia launched the Paalo SHP plant with a capacity of 3 MW as part of the efforts towards achieving this target.

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Papua New Guinea

Wenxuan Ren, Huazhong University of Science and Technology

KEY FACTS

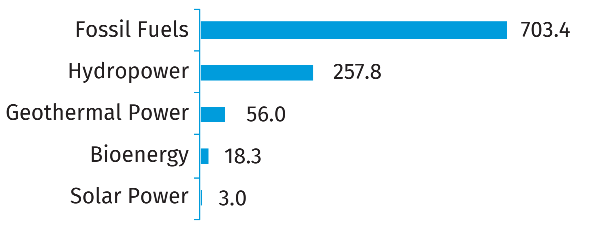
Population	8,776,119 (2019)[1]
Area	462,840 km^2 [2]
Topography	Papua New Guinea (PNG) consists of the eastern half of New Guinea, the Bismarck Archipelago, and small offshore islands and atolls. A mountainous zone called the Highlands extends from the west to the south-east of the island of New Guinea and occupies its central area. The highest summit is Mount Wilhelm reaching 4,509 metres above sea level.[3]
Climate	PNG has a hot, humid tropical climate. Seasonal temperature variation is limited, however, regionally temperature varies more significantly. In the lowlands, the annual temperature ranges from 23°C to 32°C. Cooler conditions prevail in the Highlands.[3] The El Niño Southern Oscillation (ENSO) also affects climate variability, which brings drought conditions, especially in the drier areas of PNG.[4]
Climate Change	PNG is one of the countries highly at risk of climate change and natural disasters. Warming of approximately 0.8–0.9°C has occurred between the 1900–1917 and 2000–2017 periods. Under the highest emissions scenario, by 2090, the temperature in PNG is expected to increase by approximately 3.6°C. As an island country, PNG faces the threat of the sea level rise, which by the end of the 21st century can reach up to 10 centimetres across the South Pacific region.[5]
Rain Pattern	Annual precipitation in most areas of PNG exceeds 2,500 mm, with the heaviest rainfall occurring in the highlands.[4] On the southward-facing slopes of the Highlands, the precipitation is extremely heavy, often exceeding 7,600 mm per year. However, the rainfall at Port Moresby, the capital, is less than 1,300 mm per year.[2]
Hydrology	The Fly, Purari and Kikori Rivers flow southwards into the Gulf of Papua. The Sepik, Markham and Ramu Rivers flow northwards into the Pacific Ocean. The longest river is the Sepik (1,126 kilometres) originating from the Victor Emmanuel Mountains. The Fly River forms a 1,200 kilometre-long river system with the Ok Tedi and Strickland Rivers, creating the largest river network in PNG.[6] However, because of the heavy rainfall and geologic instability of many areas, the rivers carry high sediment loads, which affects hydropower development.[3]

ELECTRICITY SECTOR OVERVIEW

The total installed electricity capacity of Papua New Guinea (PNG) in 2020 was approximately 1,084 MW. This comprised 748.4 MW from fossil fuel-fired power plants and 335.1 MW from renewable energy. Hydropower is the major renewable energy source in PNG accounting for 25 per cent (258 MW), followed by geothermal power accounting for 5 per cent (56 MW) (Figure 1).[7,8]

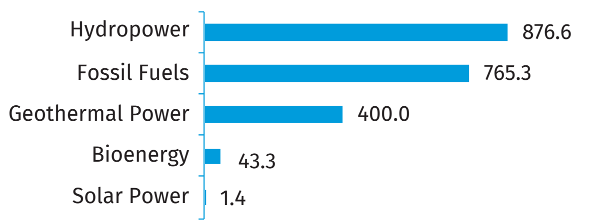
Total generation in 2019 stood at 2,087 GWh, of which renewable energy sources accounted for 1,321 GWh (63 per cent), including 42 per cent from hydropower, 19 per cent from geothermal power and 2 per cent from bioenergy (Figure 2).[7] In the Independent Power Producer (IPP) Policy, PNG set a target to achieve 100 per cent generation from renewable energy sources by 2050.[9]

Figure 1. **Installed Electricity Capacity by Source in Papua New Guinea in 2020 (MW)**



Source: IRENA[7]

Figure 2. **Annual Electricity Generation by Source in Papua New Guinea in 2019 (GWh)**

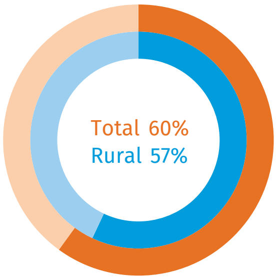


Source: IRENA[7]

PNG Power Ltd (PPL) is a state-owned entity that is in charge of electricity generation, transmission, distribution and retail services for PNG consumers.[10] It operates three major grid systems in the country, namely, the Port Moresby System, the Ramu System and the Gazelle Peninsula System, as well as several mini-grid systems, mostly powered by diesel generation sets and supplying electricity to small towns and rural areas.[11] In some locations electricity is also supplied by such independent producers as churches, mines, industrial and agricultural enclaves, which provide electricity to nearby areas.[12]

In total, approximately 60 per cent of the population has access to electricity. In rural areas, 57 per cent of the population has access to electricity, while the percentage is almost 84 per cent in urban areas (Figure 3).[13] The National Development Strategic Goals state that the electricity supply must cover 70 per cent of households by 2030 and 100 per cent by 2050.[14]

Figure 3. **Electrification Rate in Papua New Guinea (%)**



Source: World Bank[13]

The Asian Development Bank (ADB) aids the energy projects of PNG through an active portfolio of USD 240 million and proposed investments of a further USD 493 million. These projects aim to extend the electricity distribution network and improve the renewable energy supply in urban areas. The Town Electrification Investment Programme approved in 2010 is one of the energy projects in PNG funded by ADB. The first tranche of funding (2010–2021) covers the construction of 150 kilometres of 66 kV transmission lines connecting Bialla and Kimbe and the 3 MW Divune hydropower plant. The second tranche (2017–2022) covers the construction of the 3 MW Ramazon hydropower plant in the Autonomous Region of Bougainville, the rehabilitation of the 18 MW Yonki Toe of Dam hydropower plant in Eastern Highlands Province and the 10 MW Warangi hydropower plant in East New Britain Province. This project will also support the development of the renewable energy policy framework and provide environment-friendly investment for off-grid areas.[15]

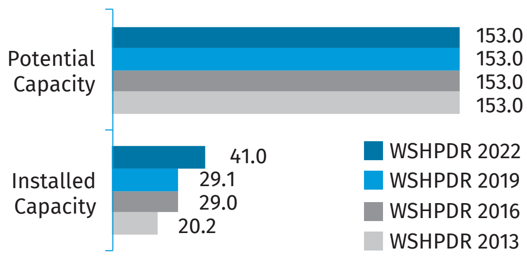
Another recent project including hydropower development is the Energy Utility Performance and Reliability Improvement Project (EUPRIP) approved by 2021. It will be supported by USD 30 million from the International Bank for Reconstruction and Development (IBRD) financing blended with reimbursable grants from the Global Infrastructure Fund (GIF) and possibly other funding sources. Upgrading PPL infrastructure is the major component of the project and will cost USD 15.8 million. Moreover, USD 3.8 million of funding will be provided for technical assistance for the development of the 80 MW Naoro-Brown run-of-river hydropower project, development of a suitable gas-to-power project in the Southern Highlands, investment in network expansion and assessment of the rehabilitation potential of existing hydropower plants.[16]

The high reliance on diesel generator sets leads to high electricity tariffs.[11] Independent Consumer and Competition Commission (ICCC) is the regulator responsible for setting the electricity tariffs. In 2018, the electricity tariff stood at 0.70 PGK/kWh (0.22 USD/kWh) for general consumers and at 1.00 PGK/kWh (0.31 USD/kWh) for industrial consumers.[20] However, in March 2018, PPL proposed to the Government to reduce tariffs by 50 percent to make electricity affordable and also to achieve the Government's electrification targets.[17]

SMALL HYDROPOWER SECTOR OVERVIEW

Although large hydropower is important to the energy mix of PNG, small hydropower (SHP) can also reduce the use of expensive diesel generators. The definition of SHP in PNG is up to 10 MW. The installed capacity of SHP in PNG is 41 MW, while the potential is estimated to be 153 MW. This indicates that approximately 27 per cent has been developed. Compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the potential remained unchanged, whereas the installed capacity increased as a result of the launch of two new SHP plants (10 MW Rouna 3 and 1.9 MW Divune) (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Papua New Guinea (MW)**



Source: VisionRI,[12] *WSHPDR 2013*,[18] *WSHPDR 2016*,[19] *WSHPDR 2019*[20]

As of 2020, 11 SHP plants were operating in PNG (Table 1). Both the Warongoi and Rouna 3 SHP plants have the capacity of 10 MW. Under the Town Electrification Investment Programme, the Warangoi plant will be rehabilitated to increase its generation and extend the operational lifetime to 25 years.[21] In 2019, unit 2 of the Rouna 3 plant was out of operation because of a system failure and power surge. After repairing and maintenance works, the Rouna 3 (both unit 1 and unit 2) was back in full operation and has already supplied electricity to the main grid.[22]

The Divune run-of-river plant funded by ADB is already supplying 1.9 MW to Popondetta (planned to reach 3 MW).[23] Moreover, PPL oversees the construction of the 3 MW Ramazon hydropower plant, which is to be completed in 2023 and reduce 19,040 metric tonnes CO_2e per year.[24] Another 10 MW PNG FP Bauune hydropower project is in the stage of feasibility investigation.[11]

PNG has abundant untapped hydropower resources. The total estimated hydropower (large- and small-scale) potential of PNG is approximately 15,000 MW, with a considerable potential in the Purari River in Western Province, the Brown River and the Vanapa River catchment in the Central Province, the Gumini River in Milne Bay and Kimadan River in New Ireland Province.[14,22,25] The SHP potential has been estimated at approximately 153 MW from more than 79 sites.[26] No further feasibility studies of SHP potential have been carried out. However, according to the national electrification roll-out plan, the World Bank is funding a feasibility study to assess hydropower potential.[11]

Table 1. **List of Existing Small Hydropower Plants in Papua New Guinea (MW)**

Name	*Capacity (MW)*	*Owner*	*Area supplied*
Warongoi (1979)	10.00	PPL	Gazelle Peninsula
Rouna 3	10.00	PPL	National Capital District
Baiune/ Bulolo	5.70	PNG Forest Products	PNGFP and town of Wau (Morobe)
Rouna 1	5.50	PPL	National Capital District
Yuk Creek	2.40	Ok Tedi Mining Limited	Ok Tedi Mine and communities in North Fly District
Divune	1.90	PPL	Popondetta
Sinnumu Set	1.50	PPL	National Capital District
Lake Hargy	1.50	PPL	Bialla
Tolukuma	1.50	Tolukuma Mines	Mine supply
Ru Creek	0.80	PPL	Kimbe
Sohun	0.20	PG	Namatanai
Total	**41**		

Sources: VisionRI,[12] Department of Public Enterprises & Department of Petroleum and Energy[14]

RENEWABLE ENERGY POLICY

The Government's Vision 2050 directs that by 2050, renewable energy should supply all electricity in the country.[11] However, so far there is no comprehensive renewable energy policy proposed in PNG and specific policy interventions need to be promoted and developed to achieve the Vision 2050 goal. In line with the PNG Vision 2050, the target of the National Energy Policy 2017–2027 is to provide accessible, reliable, sustainable and affordable energy. The policy identifies the need to harness renewable energy sources to accelerate electrification in off-grid and rural areas through policy interventions, increased investment, specialized business entities and appropriate technologies.[25]

The Papua New Guinea Development Strategic Plan, 2010–2030 (PNGDSP) predicts that development of hydropower resources could support electricity-intensive industries, such as aluminium melting, as well as export of additional electricity to Australia and Indonesia. While the PNGDSP foresees further hydropower development to meet future demand, there is no clear implementation plan to realize the existing potential.[27]

In order to support the development of SHP, several actions need to be undertaken by the Government:

- The promotion of investment in the infrastructure for new SHP projects and SHP rehabilitation projects;
- The provision of adequate financial resources for carrying out feasibility studies of potential SHP sites;
- Creation of a hydrological database for hydropower development;
- The mitigation and addressing of competing stakeholder interests (landowner issues);
- Promoting stakeholder participation in all power infrastructure projects.[25]

The specific policy and legislation for feed-in tariffs (FITs) will be set in the Renewable Energy Policy, which is to outline strategies for the development of each renewable energy source and incentives for their development.[25]

COST OF SMALL HYDROPOWER DEVELOPMENT

The 10 MW Warongoi hydropower project had a total cost of approximately USD 6.00 million and was funded by ADB.[28] The 3 MW Rouna 3 hydropower project cost PGK15.6 million (USD 4.5 million) and was funded by the Government of Japan.[29]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key barriers to SHP development in PNG include:

- PNG rivers have quite high sediment load, resulting in turbine silting and high operation and maintenance costs;
- High initial investment costs;
- Insufficient geological and hydrological data to support the development of SHP.[25]

Enablers for SHP development in PNG include:

- Significant hydropower potential;
- Availability of funding from various sources;
- The available and clear strategies set out in the National Energy Policy 2017–2027.

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Samoa

Ren Wenxuan, Huazhong University of Science and Technology

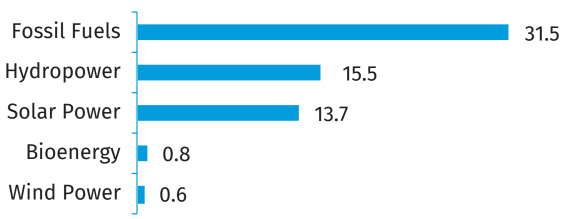
KEY FACTS

Population	202,506 (2020)[1]
Area	2,840 km[2 2]
Topography	Samoa consists of nine islands, of which four are inhabited.3 The terrain of the larger islands consists of narrow coastal plains with volcanic, rocky, rugged mountains in the interior.4 The highest point in Samoa is Mount Silisili, at 1,858 metres above sea level, which is a volcano located approximately at the centre of Savaii Island.[5]
Climate	There is relatively little seasonal variation in temperature in Samoa. The mean annual temperature ranges between 26°C and 31°C. Humidity is usually high, averaging 80 per cent or above. There are two major distinct seasons: the hot and wet season, which lasts from November to April, and the cool and dry season, which starts in May and ends in October. Night temperatures are cooler during the dry season when south-east trade winds dominate.[6]
Climate Change	Samoa has experienced warming of approximately 0.6°C between 1980 and 2018. Under the highest emissions scenario, temperature increase in Samoa is projected to reach 2.7°C by the end of the century. The number of hot days and hot nights has increased significantly. Samoa has already witnessed sea level rise of 5.2 millimetres each year and it is projected to continue to rise over the 21st century and increase by a total of 7–17 centimetres by 2030. Extreme rainfall can cause dangerous flooding, as has already been observed in parts of Samoa.[7]
Rain Pattern	Annual mean rainfall in Samoa ranges from 3,000 mm to 6,000 mm. Approximately 70 per cent of the mean annual rainfall is observed during the hot and wet season. The windward side (south and south-east) of the main islands receives more rainfall than the rain-shadowed side (mainly north and north-west).[6]
Hydrology	Similar to many other island nations, Samoa has uniquely fragile water resources.[7] All the rivers in the country are shallow and limited in length. The longest river is the Vaisigano. However, there is some potential for hydropower development on both the Upolu and Savaii Rivers.[3]

ELECTRICITY SECTOR OVERVIEW

The total installed electricity capacity of Samoa in 2020 was approximately 62 MW. This comprised 31.5 MW from fossil fuel-fired power plants and 30.5 MW from renewable energy. Hydropower is the major renewable energy source in Samoa with a capacity of 15.5 MW. The capacity of solar power is 13.7 MW and there is 0.6 MW from onshore wind power and 0.8 MW from biogas (Figure 1).[8,9,10]

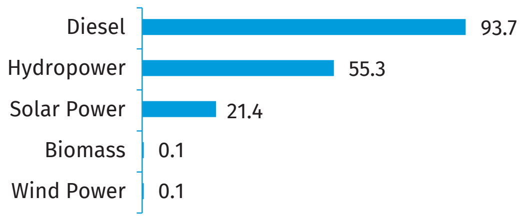
Figure 1. **Installed Electricity Capacity by Source in Samoa in 2020 (MW)**



Source: IRENA,[8,9] ADB[10]

Total generation in 2020 stood at 171 GWh and was mainly from diesel (55 per cent), while almost 80 GWh (45 per cent) was generated from renewable energy sources (Figure 2).[11] Currently, Samoa is heavily reliant on imported diesel for generation. However, under the United Nations Framework Convention on Climate Change, the Nationally Determined Contribution (NDC) of Samoa set a target to achieve 100 per cent generation from renewable energy sources by 2025.[12]

Figure 2. **Annual Electricity Generation by Source in Samoa in 2020 (GWh)**



Source: SBS[11]

Since 2016, the electrification rate in Samoa has been at approximately 100 per cent, both in rural and urban areas.[13] Approximately 95 per cent of households in Samoa have access to grid electricity and the rest are connected to small diesel generators or solar power systems.[10]

The Electric Power Corporation (EPC) is the state-owned utility company of Samoa which is mandated to generate, transmit, distribute and sell electricity. The EPC supplies electricity to nearly every household, business, community and government institution in Samoa.[14] Currently, EPC operates eight hydropower plants (one in Savaii), solar power plants at Apolima Island, Tuanaimato, Vaitele, Tanugamanono and Salelologa Savaii, a wind power plant at Vailoa Aleipata and diesel power plants at Fiaga Upolu and Salelologa Savaii.[15] The EPC is advancing a programme to reduce reliance on imported fuels and increase the use of renewable energy resources.[12] From 2015 to 2020, 31 GWh of renewable energy generation (18 per cent of total generation) was added by EPC.[16]

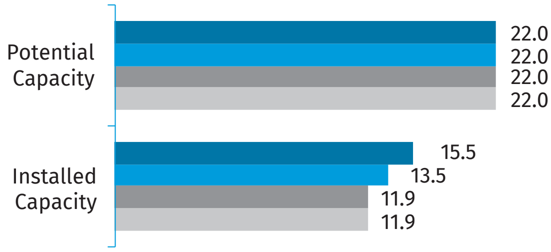
Since the Electricity Act of 2010 came into effect, the Electricity Regulator has the responsibility to review and approve tariff change proposals. Over several years, the tariff structure and the rates changed and improved continually. Compared with the electricity price in 2015, in 2020 the average electricity tariff saw a 26 per cent reduction.[16] The tariff classes were adjusted between 2020 and 2021, with the category of induction meter consumers and cash power consumers being replaced by a new tariff structure based on the post-paid and pre-paid categories. In 2022, the EPC was permitted to charge post-paid consumers 0.0063–0.0067 WST/kWh (0.0023–0.0025 USD/kWh) and 0.52–0.63 WST/kWh (0.0019–0.0023 USD/kWh) for pre-paid consumers.[17] For very large users (top 100), EPC aims to develop a new basis for setting fixed charges according to peak electricity demand.[14]

SMALL HYDROPOWER SECTOR OVERVIEW

In Samoa, there is no official definition of small hydropower (SHP). For this chapter, the standard definition of up to 10 MW will be used.

The total installed capacity of all SHP plants in Samoa is 15.5 MW.[10] The potential capacity is estimated at 22 MW.[6] Compared to the results of the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity increased by 2 MW due to the addition of a third generator to the Taelefaga SHP plant. At the same time, no new studies have been conducted, therefore, the potential capacity remained unchanged (Figure 3).

Figure 3. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Samoa (MW)**



Source: ADB,[10] *WSHPDR 2019*,[18] *WSHPDR 2013*,[19] *WSHPDR 2016*[20]

All hydropower plants existing in Samoa are small-scale (Table 1). The 1.05 MW Alaoa hydropower plant built in 1959 was the first SHP plant to come into operation in the country. Later on, another four hydropower plants were constructed: the 4 MW Taelefaga plant on the Afulilo Dam, 3.5 MW Lalomauga plant, 1.9 MW Samasoni plant and 1.74 MW Fale ole Fe'e. In the 1990s these SHP plants supplied more than 85 per cent of the country's electricity. However, with time, because of growing electricity demand, their share in total electricity generation declined.[21]

The Asian Development Fund, Clean Energy Fund under the Clean Energy Financing Partnership Facility, European Union and Government of New Zealand funded the Renewable Energy Development and Power Sector Rehabilitation Project in Samoa, which started in 2013 and was completed in 2021. This project rehabilitated the Alaoa, Fale ole Fe'e and Samasoni SHP plants damaged by Cyclone Evan in 2012. In 2017, a total of 4.69 MW of SHP capacity was reconnected to the grid: 1.05 MW from the Alaoa plant, 1.74 MW from the Fale ole Fe'e plant and 1.90 MW from the Samasoni plant. Another outcome of this project was the addition of another 3.30 MW of new SHP capacity to the grid: 0.46 MW Tafitoala-Fausaga plant, 0.16 MW Faleata plant, 0.68 MW Fuluasou plant and another 2.00 MW generator at the Taelefaga SHP plant.[10]

Table 1. **List of Existing Small Hydropower Plants in Samoa**

Name	*Location*	*Capacity (MW)*
Taelefaga	Upolu	6.00
Lalomauga	Upolu	3.50
Samasoni	Upolu	1.90
Fale ole Fe'e	Upolu	1.74
Alaoa	Upolu	1.05
Fuluasou	Upolu	0.68
Tafitoala-Fausaga	Upolu	0.46
Faleata	Savaii	0.16

Source: ADB[10]

The 0.16 MW Faleata SHP plant was installed in 2019 on the island of Savaii. It can produce 500 MWh per year, which is approximately 4 per cent of the annual electricity demand of Savaii, and provides electricity to nearly 800 families on the island.[22] Another recently launched project is the 0.46 MW run-of-river Tafitoala-Fausaga SHP plant in the south of Upolu Island, upstream of the villages of Tafitoala and Fausaga. The plant generates approximately 1,820 MWh annually.[23] In 2020, the bid for another SHP project, 750 kW Tiapapata plant, was launched.[24]

EPC continues investing in the development of hydropower in the country. However, in 2020 electricity generation from hydropower decreased by 16 per cent, or 8 GWh, compared to the previous year, because of the need for repair and maintenance of the damaged key plants. Although high financial costs are incurred for rehabilitation of the hydropower fleet, hydropower generation remains the most cost-effective source at 0.002 WST/kWh (0.0007 USD/kWh) and accounts for a significant share of electricity generation in the country.[16]

RENEWABLE ENERGY POLICY

The Government's vision for the energy sector is to ensure access to reliable, affordable and environmentally friendly energy for all, as outlined in the 2007 Samoa National Energy Policy (SNEP). The objectives for the sector include increasing the share of generation from renewable energy sources to 20 per cent by 2030, which had been achieved before 2014.[25] Further, the Strategy for the Development of Samoa (SDS) 2016/17–2019/20 identified quality energy supply based on renewable energy sources as a key strategic outcome. In this strategy, renewable energy development was defined as the main focus in the energy sector from 2016 to 2019. Some of the specific objectives set were to increase renewable energy investment and reach 100 per cent generation from renewable energy sources by 2017.[26] However, the existing installed capacity was insufficient to support this goal. Therefore, the updated target set in the NDC of Samoa report is to achieve 100 per cent electricity generation from renewable energy by 2025 as well as to reduce greenhouse gas emissions.[27]

The Samoa Energy Sector Plan (SESP) 2017–2022, which, in line with the SDS, outlines measures for improved access to quality energy supply, identified the following key issues to be addressed in the renewable energy sector:

- Increase the share of renewable energy (hydropower, solar power, wind power) in the overall energy mix;
- Increase public awareness about the benefits of renewable energy and improved energy efficiency;
- Strengthen partnerships among stakeholders for knowledge and experience sharing;
- Develop local capacity;
- Develop a centralized database of renewable energy projects;
- Provide a legislative and regulatory framework for the expansion of renewable energy capacity.[12]

To support electricity generation from renewable energy sources, in 2017 the Office of the Regulator introduced a feed-in tariff (FIT) policy. The payment levels are differentiated by technology type, project size, resource quality and project location. This policy allows power producers to sell electricity generated from renewable energy sources to the off-taker at a pre-determined rate for a set period.[28]

COST OF SMALL HYDROPOWER DEVELOPMENT

The 0.46 MW Tafitoala-Fausaga plant and 0.16 MW Faleata plant projects had a combined capital value of USD 6.54 million, with a 70 per cent of the total being civil works costs and 30 per cent mechanical and electrical costs.[22] In 2018, a USD 6.07 million grant was allocated for building a 0.68 MW SHP plant at Fuluasou. Further, the Renewable Energy Development and Power Sector Rehabilitation Project cost was USD 10.73 million for the rehabilitation of SHP plants.[10]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key barriers to SHP development in Samoa are:

- Lack of monitoring data on water resource potential;
- Low accuracy and reliability of available data on projects;
- Decreasing load factors on existing hydropower plants due to climate change and, in part, the removal of vegetation in the catchments;
- Hydropower plants can be damaged by natural disasters and it remains difficult to repair and replace the components because of the unreliability of the Pacific shipping delivery;
- Resistance of communities to hydropower development on local river systems.[19,29]

Enablers for SHP development in Samoa include:

- Available undeveloped potential;
- Policy focus on renewable energy development;
- Availability of funding from various sources as well as FITs;
- Experience in SHP development and rehabilitation.

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Solomon Islands

Ren Wenxuan, Huazhong University of Science and Technology

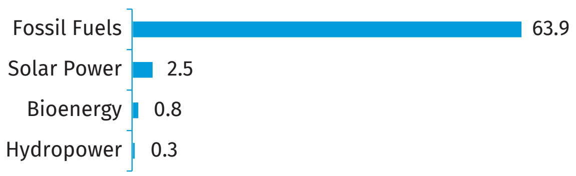
KEY FACTS

Population	686,878 (2020)[1]
Area	27,990 km^2 [2]
Topography	Solomon Islands consist of 992 islands, of which 147 are inhabited. The terrain of the islands is mostly dominated by deeply forested and rugged mountains. There are also low-lying coral atolls. The highest point is Mount Popomanaseu, a volcanic mountain reaching 2,335 metres above sea level.[3,4,5]
Climate	Solomon Islands have a warm, tropical climate all year round with little seasonal variation in temperature. The mean annual temperature ranges between 25°C and 32°C.6 There are two major distinct seasons: the wet season from November to April and the dry season from May to October.7 The climate of Solomon Islands is heavily affected by the El Niño Southern Oscillation (ENSO), which causes drought, floods and frequent tropical cyclones.[6]
Climate Change	The country faces the effects of climate change including changing weather patterns, extreme events and accelerated coastal erosion due to sea level rising.8 The temperature increased by 0.12–0.18°C per decade since the 1950s. The intensity and frequency of extreme heat are projected to increase. The sea level has risen by approximately 8 millimetres per year, which is higher than global projections, threatening local communities near the coastline.[9]
Rain Pattern	The precipitation ranges between 3,000 and 5,000 millimetres annually.6 In the dry season on average approximately 600 millimetres falls compared with upwards of 1,800 millimetres in the wet season.[7]
Hydrology	The islands' rivers are short and narrow. The Lungga on Guadalcanal Island is the longest river. The Tina River, also on Guadalcanal, has abundant hydropower potential.[10]

ELECTRICITY SECTOR OVERVIEW

In 2021, the installed generation capacity of Solomon Islands was 67.5 MW. This comprised 63.9 MW from thermal power plants powered by imported refined petroleum fuels, 2.5 MW from solar photovoltaics (PV), of which 1.5 MW was off-grid, 0.8 MW from bioenergy (solid biofuels and liquid biofuels) and 0.3 MW from hydropower (Figure 1).[11]

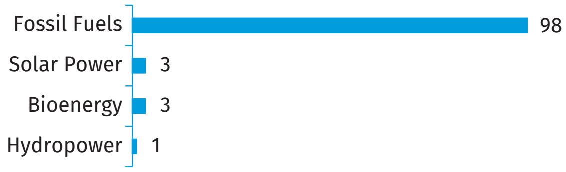
Figure 1. **Installed Electricity Capacity by Source in Solomon Islands in 2021 (MW)**



Source: IRENA[11]

Total electricity generation for 2019 stood at 105 GWh and was mainly from non-renewable energy (93 per cent), while 7 GWh (7 per cent) was generated from renewable energy sources (Figure 2).[11,12] More than 86 per cent of electricity in Solomon Islands in 2019 was generated by the diesel-fired Lungga and Honiara power plants, which produced a total of 86 GWh. Meanwhile, the mini-grids and the Henderson solar power plant produced 13 GWh (13 per cent).[13]

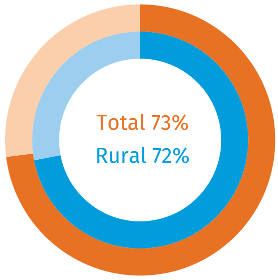
Figure 2. **Annual Electricity Generation by Source in Solomon Islands in 2019 (GWh)**



Source: IRENA[12]

Solomon Islands Energy Policy 2014 set two specific targets on electricity access — for grid-connected electricity access in urban areas to reach 80 per cent by 2020 and access to electricity in rural households and institutions to reach 35 per cent by 2020.[14] In 2020, more than 73 per cent of the population had access to electricity. However, the target for urban areas had not been achieved by 2020, although it saw a prominent increase compared with 2009 (77 per cent vs. 21 per cent). For rural areas, the electrification rate reached 72 per cent, which was twice as high as the target set in 2014 (Figure 3).[15]

Figure 3. **Electrification Rate in Solomon Islands in 2020 (%)**



Source: World Bank15

Under the State-Owned Enterprises Act 2007, Solomon Islands Electricity Authority (SIEA), trading as Solomon Power (SP), is responsible for the electricity generation, distribution and selling to connected customers in approved areas in the country. In 2018, SIEA commenced the Electricity Access and Renewable Energy Expansion Project, funded by the World Bank, to deliver renewable energy mini-grids, electricity connections in low-income areas and new grid-connected solar power.[16,17]

The Government of Solomon Islands conducted a feasibility study of hydropower potential on the Tina River near Honiara, the capital city. A site with 15–20 MW of potential capacity and annual electricity generation of over 70 GWh was identified.[16] In 2017, the 15 MW Tina River hydropower project, the largest hydropower project in the country was officially approved. The cost of the project is USD 240.48 million and it is to be completed in 2025. The new project will allow increasing electricity generation from renewable energy in Honiara, with hydropower as a result accounting for approximately 68 per cent of the city's total generation.[18]

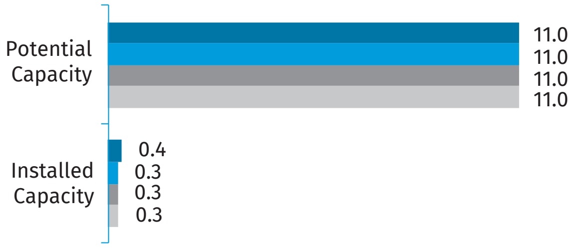
Under the Electricity Tariff (Base Tariff and Tariff Adjustments) Regulations 2016, the customers are divided into two categories — regular and non-regular — and are further classified as domestic, commercial and industrial customers. The electricity tariffs valid from 1 June 2021 for domestic regular consumers range from 5.27 SBD/kWh (0.65 USD/kWh) for consumption of less than 50 kWh to 6.18 SBD/kWh (0.76 USD/kWh) for consumption of more than 500 kWh. For the commercial and industrial regular customers, the rate is 5.27 SBD/kWh (0.65 USD/kWh) and 5.15 SBD/kWh (0.63 USD/kWh), respectively.[19]

SMALL HYDROPOWER SECTOR OVERVIEW

In Solomon Islands, there is no official definition of small hydropower (SHP). For this chapter, the standard definition of up to 10 MW will be used.

Hydropower is a renewable energy source suitable for development in Solomon Islands due to the good hydrological conditions and year-round river flows. It can both supply the major electricity grids through centralized generation and be considered for supplying rural areas via distributed mini-grids. The mountainous terrain of the country provides natural conditions for SHP development. As of 2022, the installed capacity of SHP plants was at 361 kW, while potential stood at 11 MW.[20,21,22] Thus, compared to the *World Small Hydropower Development Report (WSHPDR) 2019*, the installed capacity has increased as a result of renovation and upgrade works on several plants, while the potential remained unchanged. (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Solomon Islands (MW)**



Source: SIG,[20] IRENA,[21] *WSHPDR 2019*,[22] *WSHPDR 2016*,[23] *WSHPDR 2013*[24]

The Japan International Cooperation Agency (JICA) completed a feasibility study of hydropower potential in Solomon Islands in 2001. A total of 130 potential hydropower sites were identified, with a total potential of 327 MW, including the Lungga and Komarindi hydropower projects.[25] It should be noted, however, that the study did not account for technical obstacles, such as restricted areas or topographical limitations. The Government developed its own database of over 100 sites for potential SHP development, of which 62 had an estimated overall capacity of 11 MW.[26]

There are 13 hydropower plants with capacities of up to 150 kW, 8 of these were operational as of 2018 (Table 1).[20,21] The 150 kW Buala SHP plant is the largest SHP plant in Solomon Islands and was commissioned in 1996. However, because of unreliable operation, its service was suspended in 2007. The World Bank supported a project aiming to rehabilitate the plant, with a budget of USD 250,000. The refurbishment was completed in 2015.[27]

The Government committed to developing the 750 kW Fiu hydropower project in Malaita Province with funds of USD 15 million, however, this had to be cancelled because of land dispute issues.[28] The funds allocated to the project were transferred to a hybrid project in Auki (the capital of Malaita Province), including a solar power plant with an estimated capacity of 1.44 MW, a 560 kW backup diesel generator and a 4 MWh battery storage.[22]

Table 1. **List of Existing Small Hydropower Plants in Solomon Islands**

Name	*Capacity (MW)*	*Operator*	*Launch year*	*Funding*	*Comment*
Masupa	0.040	Community	2010	SIG	Operating
Nariao'a	0.025	Community	2004	CHINA	Operating
Raea'o	0.025	Community	2002	CHINA	Operating
Manawai	0.050	Community	1997	CHINA	Operating
Bulelavata	0.029	Community	1997	AUSAID	Operating
Ghatere	0.012	Community	1997	AUSAID/ APACE	Incomplete and damaged
Buala (Jejevo)	0.150	SIEA (Government)	1996	SIG	Operating
Vavanga	0.012	Community	1994	AUSAID/ APACE	Operating
Iriri	0.010	Community	1993	UNIDO/ APACE	Ceased operation 1997
Atoifi	0.036	Adventist Hospital	1986	Unknow	Under repair, no recent progress reported
Malu'u	0.030	SIEA (Government)	1986	SIG	Operating
Atoifi	0.030	Adventist Hospital	1973	Unknow	Ceased operation around 1980
Fauabu	0.010	Melanesian Mission	1952	Unknow	Not operational

Source: SIG,[20] IRENA,[21] *WSHPDR 2019*[22]

In 2021, the national Government fully funded the 30 kW Beulah micro-hydropower plant under the National Energy Development Project through the Ministry of Mines, Energy and Rural Electrification (MMERE) at a cost of approximately SBD 2.5 million (USD 306,375). The Beulah project, scheduled to be operational by 2026, will supply electricity to the Beulah Provincial Secondary School and nearby committees for the next 20 years.[29] According to Solomon Islands National Infrastructure Investment Plan, the estimated cost of another proposed Nafinua and Ladeabu mini-hydropower project is SBD 6 million (USD 735,300). However, there is no information on the project's capacity or its recent progress.[30]

RENEWABLE ENERGY POLICY

MMERE is responsible for the national policy formulation and implementation, legal and regulatory development in the energy sector. In the Renewable Energy Strategy and Investment Plan (RESIP), MMERE set the target to achieve 100 per cent share of renewable energy in electricity generation by 2050. SIEA set a more ambitious target of reaching 100 per cent of renewable energy by 2030.[31]

The National Energy Policy Framework 2007 sets out the broad policy directions for the planning and management of the energy sector for the 2013–2023 period. There are two overarching goals in the framework: to promote the optimal use of renewable energy technologies and to minimize negative impacts on the environment from the production, distribution and consumption of energy. The strategy for renewable energy includes:

- Increasing public awareness of the benefits of renewable energy;
- Promoting incentives for the use of renewable energy technologies;
- Ensuring there is in-country capacity to implement renewable energy projects;
- Ensuring that renewable energy resources are used in an economically and environmentally sustainable manner;
- Promoting and or supporting research and development of appropriate renewable energy technologies;
- Encouraging partnership in the development of renewable energy with the private sector.[32]

Solomon Islands Energy Policy 2014 set out the target of the utilization of renewable energy sources for power generation to be increased to 50 per cent by 2020. The policy statements include:

- Establishing an appropriate, reliable, affordable and sustainable renewable energy supply system;
- Assessing renewable energy potential and the cost for the promotion;
- Increasing productivity in rural areas by adopting renewable energy services;
- Developing renewable energy policy instruments (standards and regulations, net metering policies, market-based instruments, procurement strategies);
- Facilitating public or private partnerships for renewable energy development.[14]

The Project for Formulating Renewable Energy Road Map aiming to draft a roadmap for encouraging more renewable energy access for the Honiara grid was initiated in 2019. It provided technical suggestions and a development pathway for renewable energy expansion.[31]

For small-scale independent power producers (IPPs) in Solomon Islands, there is no format for a power purchase agreement (PPA), nor is there a feed-in tariff (FIT) scheme. Commercial conditions for each project are to be negotiated individually.[31]

COST OF SMALL HYDROPOWER DEVELOPMENT

The approximate costs of the planned SHP projects are as follows:

- The 150 kW Buala and 30 kW Malu'u plants — approximately SBD 6 million (USD 735,300);
- The 30 kW Beulah plant — SBD 2.5 million (USD 306,375);

- The Nafinua and Ladeabu pants — SBD 6 million (USD 735,300).[29,30]

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

The key barriers to SHP development in Solomon Islands include:

- Lack of standardized and streamlined approaches for land acquisition and resettlement for SHP;
- Lack of financial incentives for investment, which coupled with high upfront costs can discourage developers;
- Technical issues for hydropower facility construction such as the uncertainty of geological conditions during operation;
- Need to strengthen MMERE's capacity to develop appropriate policies and regulations.[33]

Enablers for SHP development in Solomon Islands include:

- The significant identified SHP potential;
- Policy focuses on renewable energy development;
- Availability of funding from various sources;
- Experience of SHP development and rehabilitation.

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Vanuatu

Ren Wenxuan, Huazhong University of Science and Technology

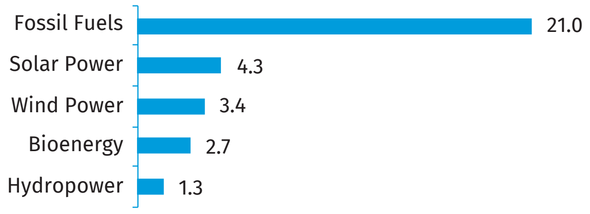
KEY FACTS

Population	299,882 (2019)[1]
Area	12,190 km^2 [2]
Topography	Vanuatu comprises 82 islands, of which 65 are inhabited.[3] Many of these islands are volcanic, covered by tropical forest and are mountainous or have a rugged terrain. The highest point is Mount Tabuemasana on Santo Island at 1,897 metres above sea level.[4]
Climate	Vanuatu has a tropical and maritime climate, with an average temperature of 24oC. The average minimum is 22oC and average maximum is 26 oC.[5] The climate of Vanuatu varies from the north to the south. It is very wet, hot and humid in the north and warm and less humid in the south. The wet season is from November to April. Temperatures are higher during this time and there is heavy rain, as well as occasional cyclones.[4] There are south-eastern trade winds from May to October.6 The warmest month is February, while the coolest is July or August.[5]
Climate Change	Vanuatu faces the effects of climate change from rising temperatures to rising sea levels and resulting storm surges. By 2030, the temperature increase in Vanuatu is projected to be in the range of 0.4–1.0°C under a high emission scenario. The sea level has risen by 6 millimetres per year since 1993 and will continue to rise to reach up to 18 centimetres. Increases in average temperatures will also result in a rise in the number of hot days and warm nights and a decline in cooler weather. Increased wet season rainfall is expected due to the projected intensification of the South Pacific Convergence Zone.[7,8]
Rain Pattern	Rainfall is heaviest in January. Average annual rainfall between 1991 and 2015 was estimated at approximately 2,500 mm.5 However, there is geographical variation in precipitation, with an average of 4,200 mm in the northern parts of the country and approximately 1,500 mm in the southern islands.4 Rainfall is variable on the smaller islands, depending on their location and size. The south-eastern (windward) side of most of the country's islands tends to receive more rainfall than the north-western (leeward) side.[9]
Hydrology	The size of each of the Vanuatu islands limits the availability of water resources.[9] The volcanic islands tend to have rivers and streams that drain from the mountains, including the Jourdain, Sarakana and Wamb Rivers.4 River courses tend to be short and flows are short-lived, particularly during the dry periods. Nevertheless, there are substantial amounts of groundwater that can provide large amounts of water, even during droughts.[4]

ELECTRICITY SECTOR OVERVIEW

The total installed electricity capacity of Vanuatu in 2019 was 33 MW.[10,11] This comprised 21.0 MW from fossil fuel-fired power plants, 3.4 MW from on-shore wind power, 2.7 MW from bioenergy (liquid biofuels), 1.3 MW from hydropower and 4.3 MW from solar photovoltaics (PV), of which 1.8 MW was off-grid (Figure 1).[10,11] Total generation for 2019 stood at 82 GWh and was mainly from fossil fuels (66 per cent), while 23 GWh (34.1 per cent) was generated from renewable energy sources. [10,11] Vanuatu does not have fossil fuel resources and is wholly reliant on imports. In 2013, the Vanuatu Department of Energy set a target to achieve a 65 per cent share of renewable energy in generation by 2020. In 2016, the target was updated to 40 per cent by 2020. In 2020, however, even the lower objective was not achieved.[10,12]

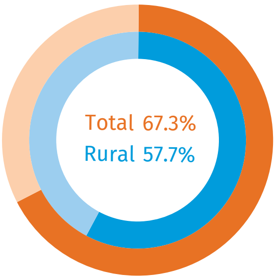
Figure 1. **Installed Electricity Capacity by Source in Vanuatu in 2019 (MW)**



Source: UN Statistics,[10] IRENA[11]

The estimated electrification rate of the country for 2020 was 67 per cent, while access in rural areas was 58 per cent (Figure 2).[13] A 100 per cent electrification target has been set for 2030.[14] Rural electrification has been challenging, partially because of the high cost of energy from diesel generation and the geographical dispersion of the 82 islands.[14] The fact that the islands are spread out and are not interconnected implies the necessity of independent systems on each island, therefore, each system incurs a fixed cost and there are limited opportunities for economies of scale.[15] The share of diesel in electricity generation greatly impacts the price paid by consumers for electricity services. The greater its share in the overall generation mix, the higher the electricity bills customers must pay.[15] Furthermore, extreme weather situations such as cyclones often have an adverse effect on the infrastructure.

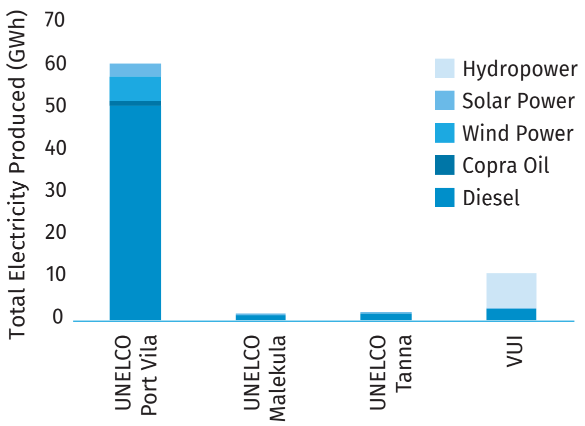
Figure 2. **Electrification Rate in Vanuatu in 2020 (%)**



Source: ESMAP[13]

There are two private companies that supply electricity in Vanuatu: UNELCO and Vanuatu Utilities and Infrastructure Limited (VUI). These companies supply electricity to the four main urban centres through private-sector concessions. The four concession areas are Port Vila (the capital) on Efate Island, Malekula, Tanna and Luganville. Diesel accounts for the largest share of electricity generation in these areas, except for Luganville, where hydropower makes up the largest proportion of the energy mix (Figure 3).[16]

Figure 3. **Energy Mix in Concession Areas in Vanuatu in 2020 (GWh)**



Source: URA[16]

Note: VUI 2020 data is inclusive of Luganville, Port Olry, Talise (Maewo), Ambae and Vanua Lava.

The electricity market was privatized after Vanuatu gained independence in 1980. The Utilities Regulatory Authority (URA) was established in 2008 to regulate tariffs on water and electricity services in the country. URA monitors the private utilities operating in concession areas and may also regulate small utilities operating outside them.[17] In October 2014, the URA put in place a new tariff system to support the integration of variable renewable energy sources into the electricity system. The aim of the tariff system is to encourage the development of small-scale on-grid solar power with a feed-in and net-metering programme. An access fee was implemented to compensate for network use. The fee only applies to domestic consumers and is based on the size of the domestic consumer's solar home system. In the case that there is excess electricity fed into the grid, it will be used to offset the fee and any fixed charges.[18]

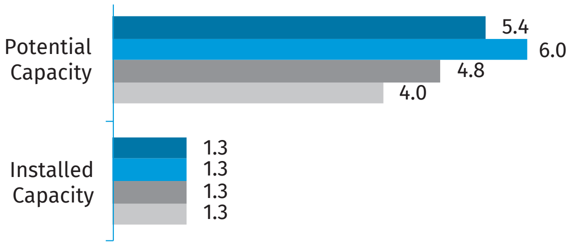
Based on a government initiative, the consumer electricity tariff system offers cross-subsidies. Small domestic customers, with consumption levels of up to 60 kWh per month, are heavily subsidized by other consumer groups in an effort to encourage electricity access and consumption by low-income earners. In June 2022, low-voltage domestic consumers using up to 60 kWh of electricity per month paid to UNELCO 0.34 VUV/kWh (0.003 USD/kWh). For consumers using up to 120 kWh per month, the price was 1.21 VUV/kWh (0.009 USD/kWh) and for those using above 120 kWh per month it was 3 VUV/kWh (0.03 USD/kWh).[19]

The first phase of the Vanuatu Rural Electrification Project (VREP) lasting from 2014 to 2020 provided a 50 per cent subsidy to private sector suppliers to distribute solar home systems. The first phase provided access to electricity to consumers where grid systems are unlikely to be economically feasible, with the target of 17,500 households, 2,000 not-for-profit community halls and 230 aid posts.[20] The second phase of the VREP lasting until June 2022 focused on increasing access to electricity in rural areas through the use of mini- and micro-grids. The project aimed to cover 37 public institutions and 8,400 rural households that are unable to access electricity and to electrify 550 households and public institutions and businesses through mini-grids.[21]

SMALL HYDROPOWER SECTOR OVERVIEW

The installed capacity of small hydropower (SHP) in Vanuatu is 1.28 MW and potential capacity is estimated at 5.4 MW.[11,22,23] Between the *World Small Hydropower Development Report (WSHPDR) 2019* and *WSHPDR 2022*, there has been no change in installed capacity, whereas the potential has decreased based on new data (Figure 4).

Figure 4. **Small Hydropower Capacities in the WSHPDR 2013/2016/2019/2022 in Vanuatu (MW)**



Source: IRENA,[11] *WSHPDR 2019*,[23] *WSHPDR 2013*,[24] *WSHPDR 2016*[25]

There is substantial untapped technical hydropower potential in Vanuatu and the topography makes run-of-river type plants the main option. The Loltong on North Pentecost and Talise hydropower projects on Maewo Island are good examples of this. The Talise plant with an installed capacity of 75 kW was launched in 2017 to supply electricity to the villages of Talise, Narovorovo and Nasawa. The 3 kW Loltong plant was launched in 2016 to provide electricity for 70 households. The largest existing SHP plant is the 1.2 MW Sarakata plant on Espiritu Santo.[12]

Thirteen potential micro-hydropower sites, with a total potential capacity of 1.5 MW and located on six different islands, have been investigated by the European Union.[26] There have been further studies to suggest a technical potential on Efate Island (e.g., 1.2 MW at Teouma) but with high cost.[26] Further, the Government of Japan proposed the construction of a run-of-river hydropower plant in Santo. A feasibility study has confirmed the existence of a suitable site with a capacity of 1 MW downstream of the existing Sarakata plant.[27] In 2021, the development of the 422 kW Brenwei hydropower plant was started based on studies undertaken in 2014 and 2016 and funded by the Asian Development Bank (ADB).[28] Based on these studies, the known SHP potential of Vanuatu stands at 5.4 MW, although further studies are required.

Vanuatu is prone to cyclones and the existing and potential small run-of-river plants are highly vulnerable to destruction during periods of very high water flow, which can exceed typical flows by a thousand times during the passage of a cyclone. As a result, the potential of a site and the potential for flood damage can only be accurately determined after the resource has been measured for at least several years.[26]

RENEWABLE ENERGY POLICY

Ensuring that there is a secure and reliable supply of energy is a high priority for Vanuatu. Since the country is highly dependent on fuel imports, consumers are exposed to certain risks. These risks include oil price variability, price shocks and interruptions to fuel deliveries due to natural phenomena or international or domestic political turmoil.[26]

A key way to manage the country's exposure to fuel price volatility and supply disruptions is to diversify energy supply. Vanuatu is rich in renewable energy resources, including hydropower, wind power, solar power and geothermal power, which could reduce reliance on imported diesel. This would not only improve energy supply but would also contribute to its sustainability.[26] It will also help to reduce electricity tariffs for consumers and achieve the supply efficiency targets. Between 2013 and 2019, the share of renewable energy in total installed capacity rose from 23 per cent to 35 per cent.[10]

The Government of Vanuatu has embarked on developing appropriate legislation in the energy sector to promote new projects to modernize the country's power industry and enable a greener energy future. The National Energy Road Map 2016–2030 identifies five priority areas for the energy sector:

- Accessible energy: Increase electricity access by households in and near concession areas, households in off-grid areas, public institutions (on- and off-grid);
- Affordable energy: Improve the efficiency of diesel generation;
- Petroleum: Reduce the cost of distributing petroleum products in Vanuatu;
- Secure and reliable energy: an energy-secure Vanuatu at all times;
- Sustainable energy: Increase the share of electricity generated from renewable energy sources; improve electricity sector end-use efficiency; improve transport (land and marine) energy efficiency; improve biomass end-use (cooking and drying) efficiency; ensure all energy infrastructure projects comply with Government and donor environmental and social safeguard requirements.[12]

Moreover, the Intended Nationally Determined Contribution (INDC) of Vanuatu has listed the following renewable energy plans to mitigate emissions:

- The installed capacity of wind power is to reach 5.5 MW by 2025;
- Install 10 MW of grid-connected solar PV by 2025 and 10 MW by 2030;
- Commission the proposed first stage of the 4 MW geothermal plant by 2025 and the second stage by 2030;
- Substitute fossil fuels with coconut oil-based electricity generation.[29]

These proposed interventions would cost approximately USD 180 million if completed within the suggested time frame.[29]

COST OF SMALL HYDROPOWER DEVELOPMENT

The investment in the 75 kW Talise SHP plant amounted to VUV 32,000,000 (USD 272,240).[30] Overall, the costs of SHP development in Vanuatu are very site-specific.

BARRIERS AND ENABLERS FOR SMALL HYDROPOWER DEVELOPMENT

There are a number of major barriers hindering SHP developments in Vanuatu, including:

- Lack of good sites near population centres;
- Complexity of transporting electricity generated from renewable energy through the transmission system to communities and public institutions;
- High costs of feasibility studies, including due to extreme weather conditions;
- The fact that Vanuatu comprises more than 80 islands that are not interconnected adds to economic challenges;
- Limited technical expertise in SHP development;
- Lack of regulation on technical specifications, in particular for power grid connection.

Enablers for SHP development in Vanuatu include:

- Available undeveloped potential;
- Availability of climate funding from various sources, including private financing and international agencies;
- Policy support for renewable energy development and micro-grids.[31]

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UNITED NATIONS
INDUSTRIAL DEVELOPMENT ORGANIZATION

Vienna International Centre
P.O. Box 300 · 1400 Vienna · Austria
Tel.: (+43-1) 26026-o
E-mail: h.liu@unido.org
www.unido.org/small-hydropower

INTERNATIONAL CENTER
ON SMALL HYDROPOWER

136 Nanshan Road
Hangzhou · 310002 · P.R.China
Tel.: (+86-571) 87132780
E-mail: report@icshp.org
www.icshp.org