UNITED NATIONS
INDUSTRIAL DEVELOPMENT ORGANIZATION

World Small Hydropower Development Report 2016

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Suggested citation:
The World Small Hydropower Development Report 2016: United Nations Industrial Development Organization, Vienna, and International Center on Small Hydro Power, Hangzhou.

References to all the citations and the digital copy are available on www.smallhydroworld.org.

Cover image: Adobe Stock

Copy-editing and design: Booksmith Productions

Table of Contents

Chapter 1 Africa

Chapter 2 Americas

Chapter 3 Asia

Chapter 4 Europe

Chapter 5 Oceania

Foreword

CHEN Lei, Minister of Water Resources, People's Republic of China and Honorary Chairman, INSHP

Hydropower is an internationally recognized source of clean and green energy, which has played an important role for the global energy supply. Driven by the increasing demand for energy and global climate change, many countries have given priority to hydropower development in the expansion of their energy sectors. Small hydropower has unique benefits – it is a mature technology which is economically feasible and has minimal impact on the environment. Small hydropower has greatly contributed to solving the problem of rural electrification, improving living standards and production conditions, promoting rural economic development, alleviating poverty as well as reducing emissions. Moreover, small hydropower is an economically efficient technology, and as such, has been highly favoured by the international community, especially by developing countries.

China is the largest developing country in the world as well as the country endowed with the richest hydropower resources. The Government has promoted hydropower to a significant position. By the end of 2015, the total hydropower capacity of China reached 320 GW with an annual output of 1,100 TWh. Hydropower plays an essential role in the energy sector of China, contributing to the adjustment of the energy mix, emission reductions, as well as the economic development of the country, which has also promoted and led hydropower development worldwide. During the 12th Five-year Plan, the Government of China paid particular attention to the small hydropower sector, promoting the people's "well-being, and safe, green, and harmonious" small hydropower development. To date, 4,400 SHP plants (up to 50 MW) have been upgraded and refurbished; as a result, installed capacity and annual output have increased by more than 20 per cent and 40 per cent respectively. Furthermore, 300 counties completed the objectives of the New Hydropower Rural Electrification County Programme by developing 5,150 MW of newly installed SHP capacity, which accounted for 50 per cent of the total increase in SHP capacity. Additionally, through the national programme Replacing Firewood with SHP, 592,000 households, totalling 2.24 million people, have been provided with access to electricity and 733,333 hectares of forest have been saved. The total installed SHP capacity of China has exceeded 75 GW, with an annual output of 230 TWh, thus, meeting the target set by the Medium and Long-term Renewable Energy Development Plan five years ahead of schedule.

Currently, the Chinese economy has entered a "new normal" characterized by increasing energy demand, as well as ecological and environmental problems, and therefore faces the critical need to adjust the energy mix, improve energy efficiency and ensure energy security. The Government of China advocates for the development concepts of "Innovation, Coordination, Green Development, Opening Up and Sharing" and the energy strategy policy of "Conservation, Clean, and Safe"; it promotes a clean, highly efficient, safe, sustainable and modern energy sector, which is reflected in the Energy Development Strategy Action Plan 2014-2020. China has a great potential for hydropower, which is an important renewable energy source. The Government will actively promote further hydropower development while taking into consideration the environmental and resettlement issues. Meanwhile, SHP development will be incorporated into a poverty alleviation strategy, and will be adapted to local conditions. By 2020, the total installed hydropower capacity of China will have reached 350 GW, of which small hydropower will account for 81 GW.

The achievements of China in small hydropower development have received worldwide attention, representing a good example for other countries. Therefore, the establishment of the International Network on Small Hydro Power (INSHP) and the International Center on Small Hydro Power (ICSHP) in China, was a logical choice. INSHP is the first international organization headquartered in China. Following its mission of an international and non-profit organization and serving the host country, ICSHP is committed to South-South cooperation, global development of small hydropower and promotion of Chinese hydropower enterprises undertaking business activities abroad. The Center has made remarkable achievements in the past 20 years. It has created a unique triangular model of cooperation between international organizations, developing and developed countries. ICSHP has become the international hub for small hydropower, leading the development trend in the international small hydropower industry and disseminating the experience, knowledge and capability of China to countries all around the world.

As the host country of INSHP, the Government of China has always supported the initiatives of INSHP and ICSHP, including cooperation with other international organizations such as the United Nations Industrial

Development Organization (UNIDO), and independent experts and scholars, in order to share the successful experience of the Chinese small hydropower industry with other countries and regions, and to promote the development of small hydropower worldwide. In December 2013, the first English version of the *World Small Hydropower Development Report 2013* (*WSHPDR 2013*) was published by ICSHP and UNIDO. The *WSHPDR 2013* was established with a global vision for small hydropower development: to provide baseline information and a strategic outlook for regional and international institutions as well as countries to develop their renewable energy plans and ensure integrated management of water resources. The report has become an important knowledge platform for global development of small hydropower.

As an update of the first edition of 2013, *WSHPDR 2016* comprises 160 national reports and 20 regional reports, with 11 new countries added compared to the previous edition. More than 230 experts and scholars in the field of small hydropower from related governmental institutions, research institutes, universities and colleges, as well as hydropower companies in those countries and regions, contributed to drafting country and regional reports. Analysis of the status of small hydropower development in each country included the following five aspects: electricity sector overview, small hydropower sector overview and potential, renewable energy policy and barriers to small hydropower development. Other issues covered in country reports include information on the power grid structure, electricity tariffs, short-term projects planned by governments, incentives, policies and plans for renewable energy development. Every effort has been made by the authors, ICSHP and UNIDO to make *WSHPDR 2016* more comprehensive, practical and authoritative.

Today, the world is entering a new era—an era of low-carbon energy, characterized by dramatic changes in the energy supply-demand relationship. The Government of China is willing to share Chinese technological innovations in small hydropower with the international community, and to advocate the idea of green development of small hydropower, as well as to warmly welcome further exchange and cooperation in the field of small hydropower. To conclude, I would like to express my sincere hope that the publishing of *WSHPDR 2016* will help make international small hydropower development inclusive and sustainable and will contribute to creating a beautiful life for all of mankind.

Foreword

LI Yong, Director General, UNIDO

To address environmental challenges, energy security and volatile fuel prices, and to pursue inclusive and sustainable industrial and economic development, leaders are strategizing ways to shift the economies from relying on traditional energy sources to renewable ones. UNIDO, as a specialized agency of the United Nations, is promoting inclusive and sustainable development and realization of industry-related Sustainable Development Goals (SDGs), particularly SDG 9, on building resilient infrastructure, promoting inclusive and sustainable industrialization and fostering innovation. UNIDO understands that access to low-cost and reliable energy based on local renewable resources for productive uses can bring economic, social and environmental dividends, such as increasing industrial competitiveness, creating jobs for all and raising incomes.

In this regard, small hydropower is an excellent renewable energy solution to meet the needs of productive uses and to electrify rural areas. It is a mature technology, which can easily be designed, operated and maintained locally. It has the lowest electricity generation prices of all off-grid technologies, and the flexibility to be adapted to various geographical and infrastructural circumstances.

Despite these benefits, the potential of small hydropower in developing countries remains untapped.

It is therefore paramount for UNIDO to foster uptake of small hydropower through awareness building, information dissemination and experience sharing on the use of renewable energy, such as small hydropower, in industries and in small enterprises, in particular. This will boost productivity, industrialization and regional economic development.

This is in line with the objectives of the *World Small Hydropower Development Report*, namely, to promote the increase of the share of this valuable source of energy in the energy mix, through informing policy on energy planning and guiding investors in entering renewable energy markets, through information and knowledge sharing.

Towards this objective, UNIDO's Department of Energy collaborated with the International Center on Small Hydro Power (ICSHP) in 2013 to develop a small hydropower knowledge platform www.smallhydroworld.org and produce the *World Small Hydropower Development Report*. This flagship initiative of UNIDO is the first compilation of valuable information on global small hydropower. It serves as a crucial guide for policymakers and investors.

In 2016, UNIDO and ICSHP, along with partners, launched this updated version of the Report and Platform, continuing our mission to inform world leaders on the status and potential of small hydropower development, and encourage stakeholders in the sector to share and disseminate this knowledge.

I would like to congratulate the experts and institutions that have contributed to this Report, making it rich in content and accurate in presentation.

Acknowledgements

The *World Small Hydropower Development Report 2016* was prepared under the overall guidance of Pradeep Monga, Director of the Department of Energy at the United Nations Industrial Development Organization (UNIDO), Cheng Xialei, Director General of the International Center on Small Hydro Power (ICSHP) and Liu Heng, Vice-President of Nanjing Hydraulic Research Institute. It is the result of two years of intense research efforts and close collaboration with the experts in the field of small hydropower.

The Report was headed by Rana Pratap Singh, Industrial Development Officer at UNIDO. This lengthy and at times arduous endeavour was coordinated by Sidney Yeelan Yap at UNIDO; Wang Xianlai and Eva Kremere at ICSHP. The Report was backed by a talented and indispensable team of researchers at ICSHP including Nathan Stedman, Tom Rennell, Marcis Galauska, Oxana Lopatina and Gonzalo Lopez.

The invaluable contributions and insightful comments received greatly enhanced the overall quality of the Report. These included authors and contributors: Fagan Abdurahmanov, Tcharabalo Abiyou, Donald Adgidzi, Lia Aghekyan, Engku Ahmad, Dennis Akande, Sameer Sadoon Algburi, Mohammad Hassan Al Zoubi, Gabrial Anandarajah, Viktor Andonov, Darlene Arguelles, Fredrik Arnesen, John Kobbina Arthur, Engku Ahmad Azrulhisham, Attila Bagi, Johor Bahru, Betsy Bandy, Sendi Baptista, Kemal Baris, Stefano Basso, Alexis Baúles, Hannes Bauer, Madhu Prasad Bhetuwal, Mme Sow Aissatou Billy, Guillaume Binet, Alaeddin Bobat, Nebiyu Bogale, Edilbek Bogombaev, Carlos Bonifetti, Roger Limoko Bosomba, Paul Bryce, Thomas Buchsbaum, Alfredo Samaniego Burneo, Ejaz Hussain Butt, Rodolfo Caceres, Martin Camille Cange, Sonya Chaoui, Piseth Chea, Zivayi Chiguvare, Gift Chiwayula, Karim Choukri, Nouri Chtourou, Romao Grisi Cleber, Bill Clement, Fred Conning, Dione Constance, Jovan Cvijic, Manana Dadiani, Vassish Dassagne, Eric Davy, Denise Delvalle, Johanna D'Hernoncourt, Sinalou Diawara, Paulo Alexandre Diogo, Pirran Driver, Khalil Elahee, Sylla Elhadji, Hussein Elhag, Mohamedain E. Seif Elnasr, Lambert Engwanda, Cayetano Espejo, Daniela Espinoza, José Fábrega, Nimashi Fernando, Soukaina Fersi, Geraldo Lúcio Tiago Filho, Sione Foliaki, Fombong Matty Fru, Tokihiko Fujimoto, Camila Rocha Galhardo, Ramon Garcia, Rinayu Garini, Carlos González, Erickl Gonzalez, Toon Goormans, Johannes G.Grijsen, Cleber Romao Grisi, Leo Guerrero, Mathias Gustavsson, Zvonimir Guzovic, Armin Hadzialic, Mohammad Hajilari, Randrianarivelo Jean de Dieu Luc Harisson, Eoin Heaney, Liu Heng, Deung-Yong Heo, Marcello Hernández, Sven Homscheid, Arian Hoxha, M.R. Ibragimova, Janis Irbe, Agustín Irizarry-Rivera, Michela Izzo, Sherab Jamtsho, Frantisek Janicek, Sergio Armando Trelles Jasso, Rim Jemli, Edy Jiménez-Toribio, Kurt Johnson, Morsha Johnson-Francis, Rán Jónsdóttir, Aaron Yancho Kaah, Furkat Kadyrov, Ramiz Kalbiyev, J.K. Kaldellis, Papias Karanganwa, Bryan Karney, Raul Pablo Karpowicz, Egidijus Kasiulis, Fredrick Kazungu, Nguy Thi Khanh, Harald Kling, Wim Klunne, John Korinihona, Igor Kovacevic, Juraj Kubica, Arun Kumar, Gianluca Lazzaro, Disashi Nyama Lemba, Zenkevich Zhanna Leonidovna, Jean-Marc Lévy, Patricia Lewin, Stelios Liaros, Roger Limoko, Galina Livingstone, Casper Lundbak, Esmenio Isabel Joao Macassa, Ewa Malicka, Ghulam Mohd Malikyar, Sharon Mandair, Ariel Marcheniagi, Miroslav Marence, Cayetano Espejo Marin, Ramon Garcia Marin, Rupeni Mario, Max Marten, Harrison Masiga, Petr Mastny, Anare Matakiviti, Leopoldo Mba, Nebiyu Bogale Mereke, Emmanuel Michael-Biririza, Lasten Mika, Jan Moravek, Conrado Moreno, Carine Mukashyaka, Tin Myint, Wimal Nadeera, N'guessan Pacôme N'Cho, Leonel Wagner Neto, Niels Nielsen, Robert Nyamvumba, Abdeen Mustafa Omer, Emna Omri, Efrain O'neil-Carrillo, Karim Osseiran, Daniel Paco, Milena Panic, Domingos Mosquito Patricio, Cláudio Moisés Paulo, Elsia Paz, Henrik Personn, Ana Milanovic Pešic, Mark Pickup, Vlad Florin Pîraianu, Jiri Pitron, Martina Prechtl-Grundnig, Nuwan Premadasa, Mairawesi Pulayasi, Peeter Raesaar, Faisal Rahadian, Mizanur Rahaman, Jorge Reyes, Lucas Rissatto, António Carmona Rodrigues, José Pablo Rojas, Irina Rotari, Vladimir Russo, Kamila Sakipova, Jorge Reyes Salazar, Alberto Sanchez, Sašo Šantl, Vahan Sargsyan, Ryspek Satylkanov, Martin Scarone, Ozturk Selvitop, Shamsuddin Shahid, Mahender Sharma, M. Hady Sherif, Manish Shrestha, Sangam Shrestha, Luciano José da Silva, Mundia Simainga, Christopher Simelum, Jérémie Sinzinkayo, Seming H. Skau, Paradis Someth, Eva Szabina Somossy, Marina Stariradeva, Janusz Steller, Phillip Stovold, Abdul-Ilah Younis Taha, Samiha Tahseen, Kati Takala, Ibrahim Ragab Mohamed Teaima, Stephan Theobold, Mikael Togeby, Petr Toman, Ernesto Torres, Bertrand Touaboy, Thierry Trouillet, Le Anh Tuan, Makhbal Tumenjargal, Eva Maate Tusiime, Philbert Tuyisenge, Jo Tyndall, Miranda Urbina, Marko Urošev, Peter Vail, Petro Vas'ko, Sandra Vatel, Carola Venegas, Akhomdeth Vongsay, David E. Weir, Harsha Wickramasinghe, Horace Williams, Mark Williams, Edmund D Wuseni, Kassius Klei Ximenes, Milena Yanuzova, Zhanna Zenkevich.

Other contributing experts were Liu Deyou, Hu Xiaobo and Lara Esser from ICSHP, Lin Ning and Li Zhiwu from the Hangzhou Regional Center (Asia-Pacific) for Small Hydro Power (HRC). Deepest gratitude is also due to Guillaume Binet, Johannes Geert Grijsen, Sergio Armando Trelles Jasso, Kurt Johnson, Furkat Kadyrov, Bryan

Karney, Wim Klunne, Gianluca Lazara, Galina Livingstone, Miroslav Marence, Niels Nielsen, Janusz Steller, Phillip Stovold, who thoroughly reviewed numerous drafts and significantly improved several sections of the Report.

The Report further benefited from constructive comments by members of the *WSHPDR* Editorial Board, specifically Linda Church-Ciocci, National Hydropower Association (NHA) and Hydro Research Foundation, Solomone Fifita, Secretariat of the Pacific Community (SPC), Motoyuki Inoue National Institute of Science and Technology Policy (NISTEP), Wim Jonker Klunne, Energy and Environment Partnership (EEP), Arun Kumar, Alternate Hydro Energy Center, Pradeep Monga, UNIDO, Hongpeng Liu, United Nations Economic and Social Commission for Asia and the Pacific (UNESCAP), Liu Heng, Nanjing Hydraulic Research Institute, András Szöllösi-Nagy, Institute for Water Education (UNESCO-IHE), Tian Zhongxing, INSHP, Kuniyashi Takeuchi, International Centre for Water Hazard and Risk Management (ICHARM), Jeffrey Skeer, International Renewable Energy Agency (IRENA) and Geraldo Tiago Filho, Centro Nacional de referencia em Pequenas Centrais Hidreletricas (CERPCH); by members of the UNIDO Publications Committee – Augusto Luis Alcorta Silva Santisteban, Adnan Seric, Jacek Cukrowski, Steffen Kaeser, Frank Hartwich, Alois Mhlanga, Patrick Nussbaumer, Thouraya Benmokrane and Michele Clara, as well as other UNIDO colleagues at the Department of Energy.

Executive Summary

The *World Small Hydropower Development Report* (*WSHPDR*) *2016* is the result of an enormous collaborative effort between the United Nations Industrial Development Organization (UNIDO), the International Center on Small Hydro Power (ICSHP) and over 230 local and regional small hydropower (SHP) experts, engineers, academics and government officials across the globe.

Prior to the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, it was clear that a comprehensive reference publication for decision makers, stakeholders and potential investors was needed to promote SHP as a renewable and rural energy source for sustainable development more effectively and to overcome the existing barriers to development. The 2016 edition aims to not only provide an update but also to greatly expand on the 2013 edition by providing improvements on data accuracy with enhanced analysis and a more comprehensive overview of the policy landscapes compiled from a larger number of countries.

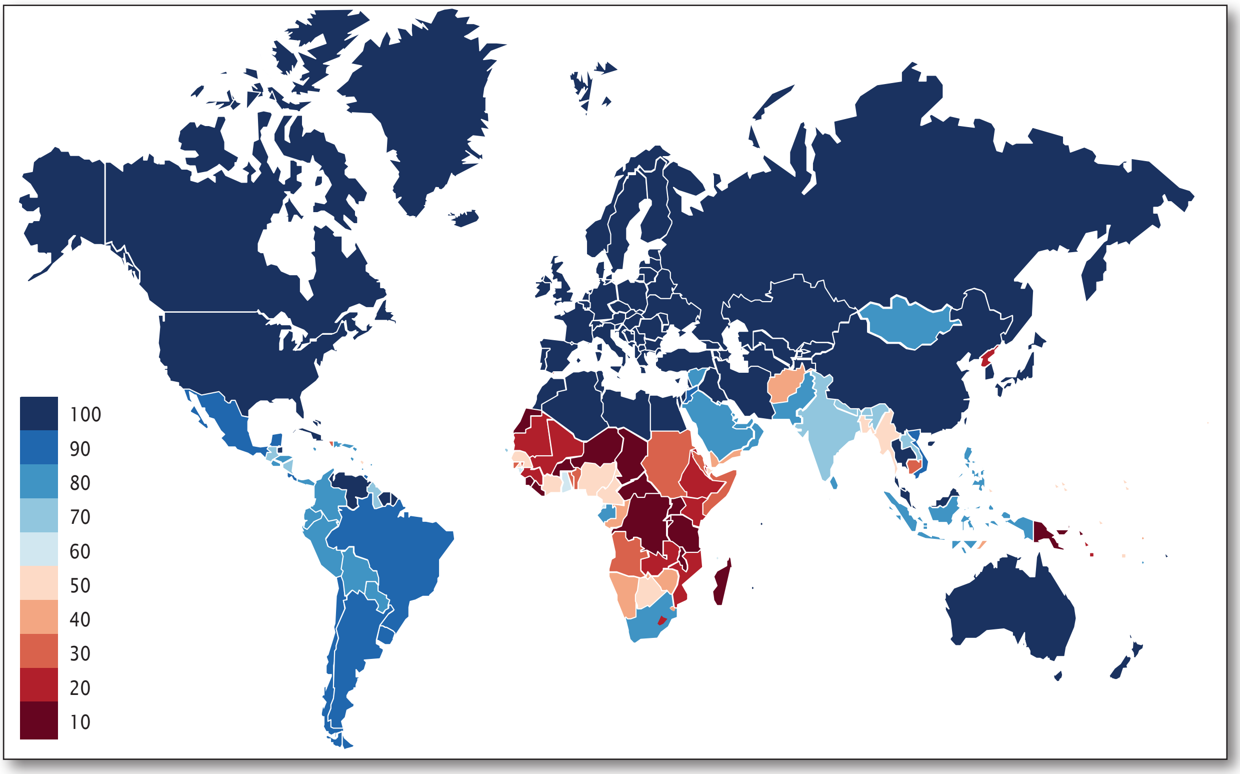
Energy remains one of the most critical economic, environmental and development issues facing the world today with some 1.2 billion people—about 17 per cent of the world's population—still lacking access to electricity (Figure 1). Clean energy and access to electricity have been recognized by the United Nations as key to development. As such, energy access is the seventh Sustainable Development Goal (SDG). Yet clean energy exists with other SDGs, including alleviating poverty, education, improving environmental conditions and combating climate change.

In both developing and developed countries, the need for clean and sustainable sources of energy is growing more acute in the face of climate change while geopolitical and economic uncertainty over traditional fossil-fuel markets highlights the importance of energy diversification and independence.

On a global scale, hydropower is the most widely utilized form of renewable energy, with over 1.2 TW of installed capacity spanning six continents. However, inadequate design and planning of hydropower projects can have a negative effect on the environment. In order to ensure sustainable development and operation of hydropower,

FIGURE 1

Electrification rates by country (%)



Source: Statistics from the World Bank

‘green hydropower’ as a concept has been developed. This is based on the principle of balancing economic and social development and environmental protection.

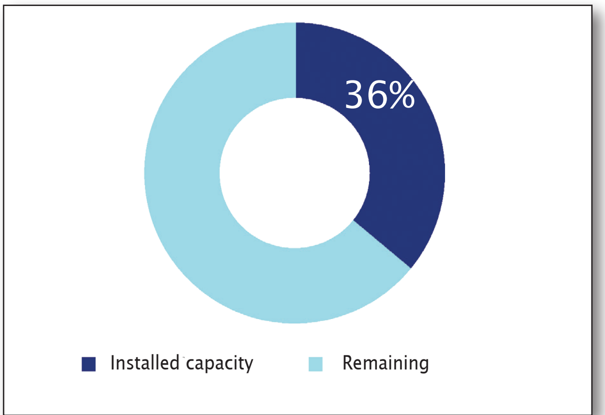
When supported by environmental protection policies and concrete supervision from the regulatory authorities, SHP can be an important renewable energy technology, contributing to rural electrification, socially inclusive sustainable industrial development as well as reduction of greenhouse gas emissions and deforestation. Therefore, it should be considered in national plans globally for development of sustainable green energy.

Global overview

The globally installed SHP capacity is estimated at 78 GW in 2016, an increase of approximately 4 per cent compared to data from *WSHPDR 2013*. The total estimated SHP potential has also increased since publishing *WSHPDR 2013* to 217 GW, an increase of over 24 per cent. Overall, approximately 36 per cent of the total global SHP potential has been developed as of 2016 (Figure 2).

FIGURE 2

Global installed SHP capacity (%)



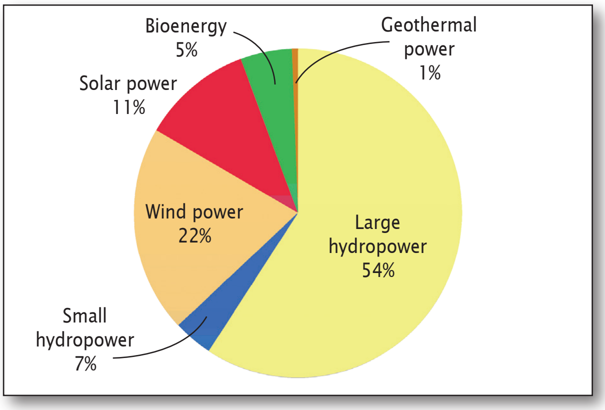
Source: ICSHP

SHP represents approximately 1.9 per cent of the world’s total power capacity, 7 per cent of the total renewable energy capacity and 6.5 per cent (< 10 MW) of the total hydropower capacity (including pumped storage). As one of the world’s most important renewable energy sources, SHP is fifth in development, with large hydropower having the highest installed capacity to date, followed by wind and solar power (Figure 3).

China continues to dominate the SHP landscape. Fifty-one per cent of the world’s total installed capacity (definition of below 10 MW) and approximately 29 per cent of the world’s total SHP potential are located in China. It has more than four times the SHP installed capacity of Italy, Japan, Norway and the United States of America (USA) combined. Together, the top five countries—China, Italy, Japan, Norway and the USA account for 67 per cent of the world’s total installed capacity (Figure 4).

FIGURE 3

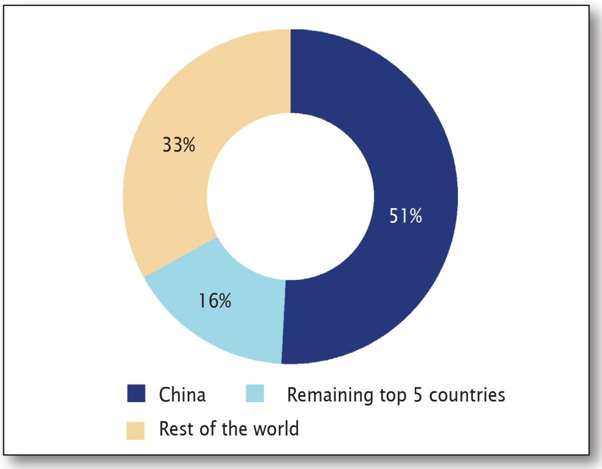
Global share of renewable energy (%)



Source: World Bank

FIGURE 4

Leading countries in SHP development (%)



Source: ICSHP

While the USA has developed a majority of its potential, reaching 57 per cent of its developed potential in 2016, Brazil has much of its SHP potential undeveloped, reaching only 22 per cent in 2016. Nevertheless, since the publishing of *WSHPDR 2013*, Brazil has increased its installed capacity by 34 per cent (up to 30 MW). The USA,

FIGURE 5

SHP by region (<10 MW)

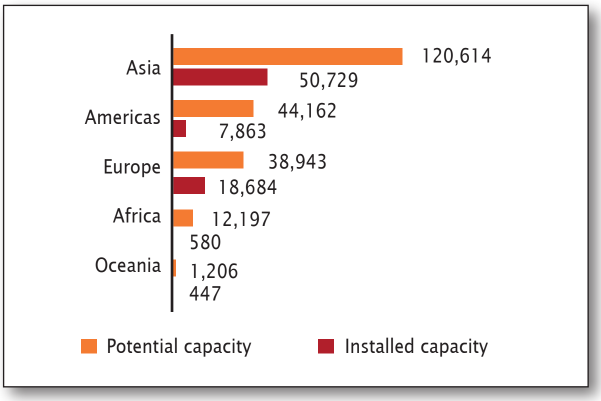


TABLE 1

Top 5 regions, sub-regions and countries in SHP development (< 10 MW)

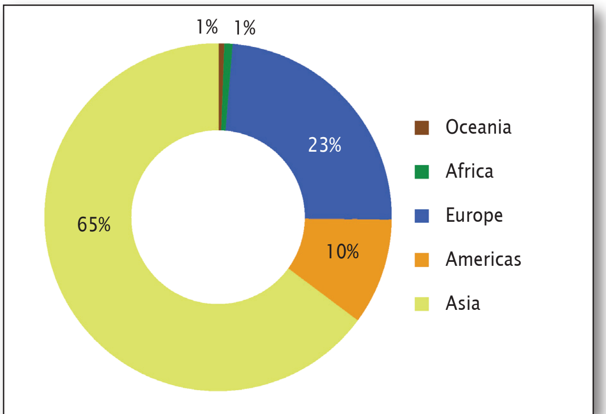
Regions/rankings	1	2	3	4	5
Regions by installed capacity (MW)	Asia	Europe	Americas	Africa	Oceania
Regions by potential capacity (MW)	Asia	Americas	Europe	Africa	Oceania
Regions by undeveloped potential (MW)	Asia	Americas	Europe	Africa	Oceania
Regions by percentage of potential developed	Europe	Asia	Oceania	Americas	Africa
Sub-regions/rankings					
Sub-regions by installed capacity (MW)	Eastern Asia	Southern Europe	Western Europe	Northern America	Northern Europe
Sub-regions by total potential capacity (MW)	Eastern Asia	South America	Southern Asia	Southern Europe	South-Eastern Asia
Sub-regions by undeveloped potential (MW)	South America	Eastern Asia	Southern Asia	South-Eastern Asia	Southern Europe
Sub-regions by % developed	Western Europe	Northern America	Northern Africa	Eastern Asia	Central America
Countries/rankings					
Countries by installed capacity (MW)	China	USA	Japan	Italy	Norway
Countries by total potential capacity (MW)	China	Colombia	India	Japan	Norway
Countries by undeveloped potential (MW)	Colombia	China	India	Chile	Japan

however, had decreased 46 per cent in installed capacity based on more accurate data in 2015. Europe has the highest SHP development rate, with nearly 48 per cent of the overall potential already installed (Figure 5).

Japan and India also have a less developed SHP sector, reaching only 35 and 18 per cent of developed potential in 2016 respectively. Compared to *WSHPDR 2013*, India's total installed capacity has increased by 18.6 per cent (up to 25 MW). Japan, however, has increased 0.8 per cent.

FIGURE 6

Installed SHP capacity by region (%)



Largely due to the dominance of China in SHP, Asia has the highest share of installed SHP capacity, with 50,729 MW, constituting approximately 65 per cent of the total share. Oceania, on the other hand, has the lowest share, with approximately 1 per cent of the total global installed SHP capacity (Figure 6).

While Asia continues to have the largest installed capacity and potential for SHP up to 10 MW, Europe has the highest percentage of SHP development, with Western Europe having 85 per cent of its potential already developed.

The Americas and Africa have the third- and fourth-highest installed capacity and potential of all five regions. In the Americas, most of the SHP is concentrated in Northern America and South America. However, the two smaller regions—the Caribbean and Central America—have yet to carry out conclusive assessments to determine their actual SHP potentials. In 2016, the Americas reached a developed SHP rate of 18 per cent. Nonetheless, Africa has a larger gap to fill as its SHP development rate is at less than 5 per cent. Eastern Africa, in particular, is the sub-region that has the most SHP potential, but also the least to be developed (Figures 7, 8 and Table 2).

FIGURE 7

Potential SHP capacity by region (%)

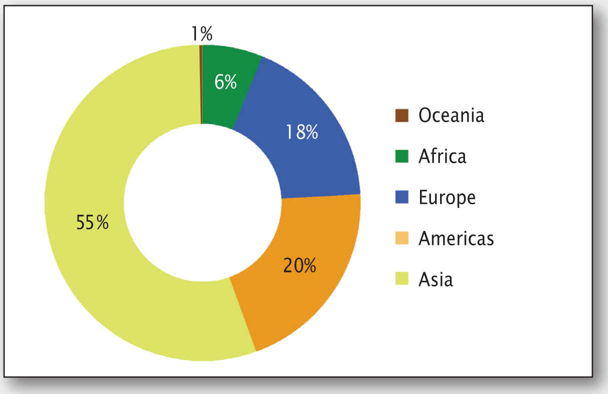
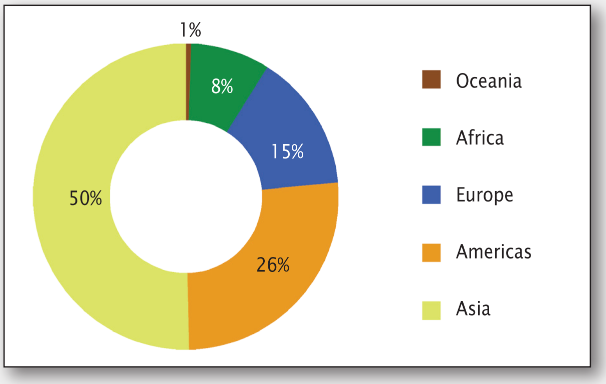


FIGURE 8

Share of remaining SHP potential by region (%)



Regionally, Asia has shown the highest increase in installed capacity, expanding its capacities by 33 per cent as compared to data from *WSHPDR 2013*. Africa has the second largest increase, by 10 per cent. However, due to the region's initial low levels of SHP installed capacity, the increase actually translates to a mere 54 MW. Thus the number is relatively little when compared to the 4,462 MW increase in Asia.

Of the 160 countries studied, approximately half of them have established national or local feed-in tariffs (FITs) or other similar fiscal incentives for SHP generators. A number of countries, such as Egypt and the Dominican Republic, have established FITs for renewable energy, but not specifically for hydropower. In other cases, such as in Mozambique and Ethiopia, FITs have been drafted and are pending for implementation. In Gambia the establishment of FITs has been declared mandatory as a part of the new energy law. However, it has not been implemented yet.

TABLE 2

SHP by region (< 10 MW)

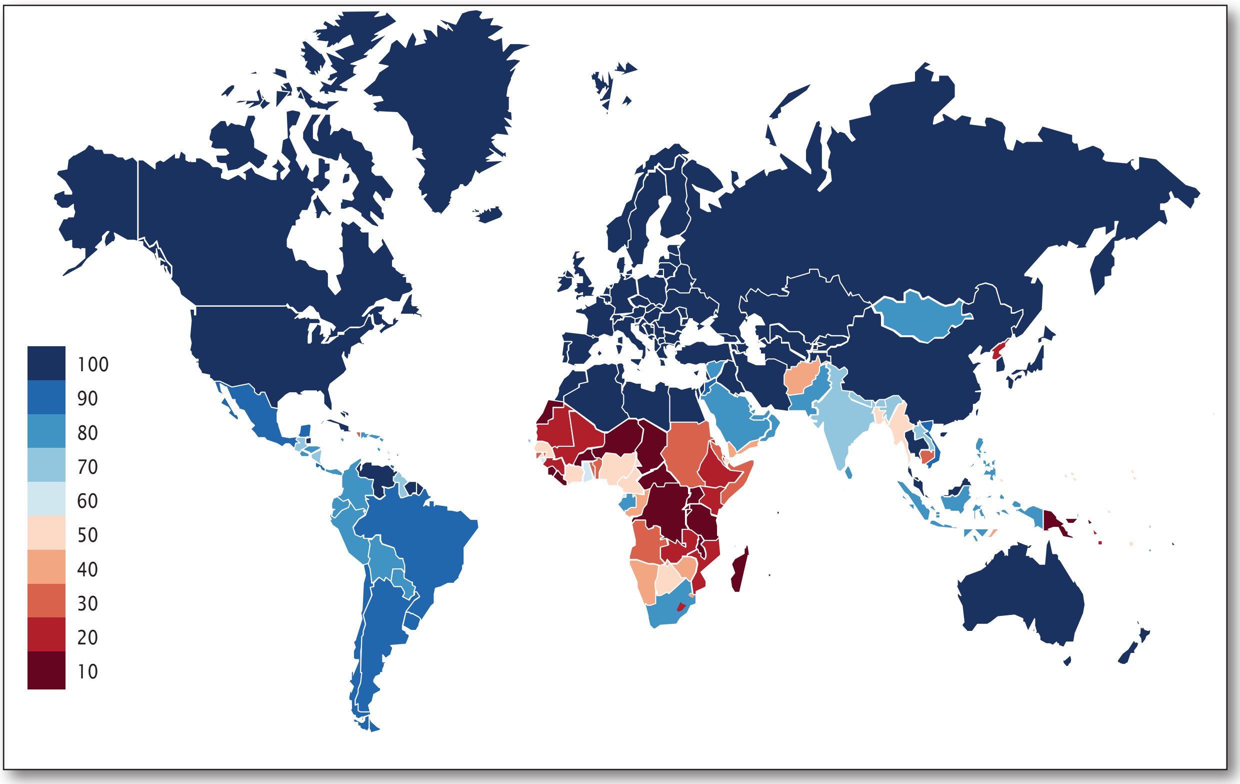
		Installed SHP capacity	Potential SHP capacity
Africa	Middle Africa	104	1,745
	Eastern Africa	216	6,759
	Northern Africa	111	189
	Southern Africa	63	392
	Western Africa	86	3,113
Americas	Caribbean	172	349
	Central America	855	1,512
	Northern America	4,798	7,662
	South America	2,039	34,638
Asia	Central Asia	221	6,087
	Eastern Asia	43,542	75,335
	Southern Asia	2,974	17,824
	South-Eastern Asia	2,340	13,642
	Western Asia	1,653	7,700
Europe	Eastern Europe	1,924	4,470
	Northern Europe	4,292	10,920
	Southern Europe	6,286	16,310
	Western Europe	6,183	7,243
Oceania	Australia and New Zealand	335	794
	PICT	112	412

Note: All data presented in this section are referenced in the respective regional summaries and country reports; electrification rate data available from the World Bank from http://data.worldbank.org/indicator/EG.ELC.ACCS.ZS.

The world at a glance

FIGURE 9

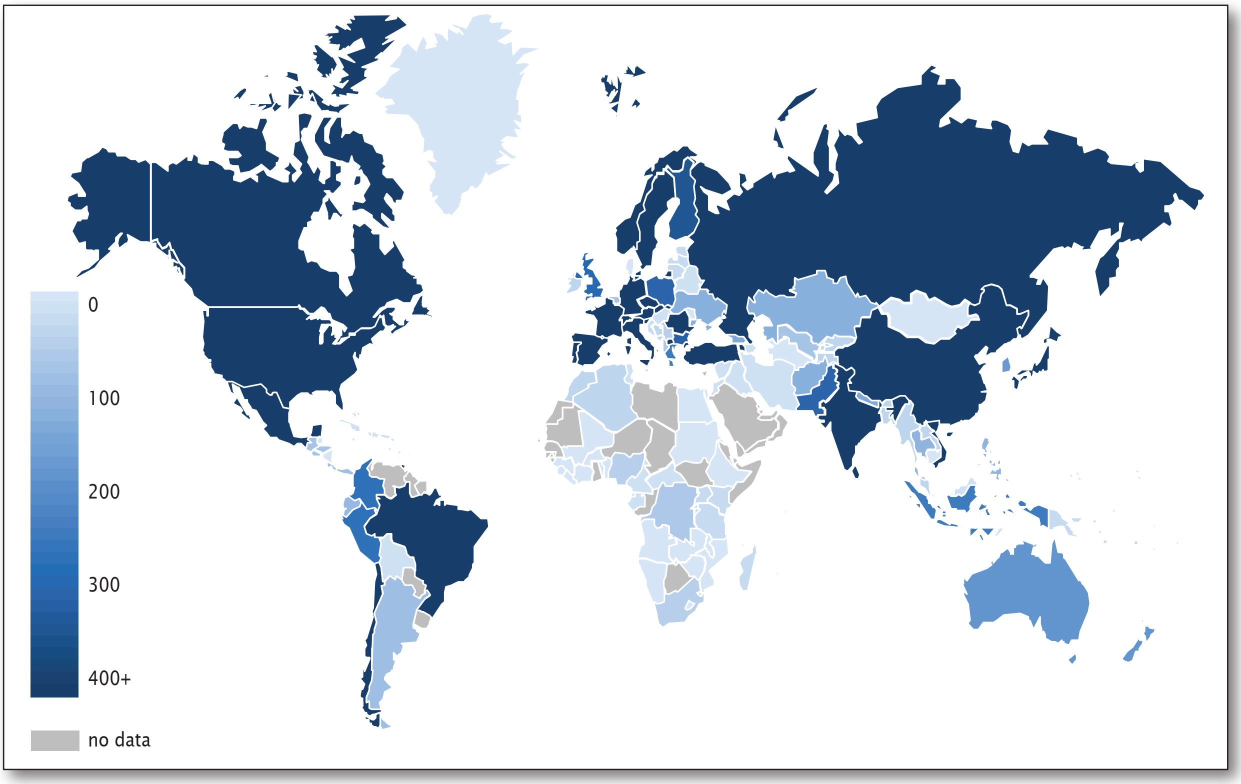
Electrification rates by country (%)



Source: Statistics from the World Bank

FIGURE 10

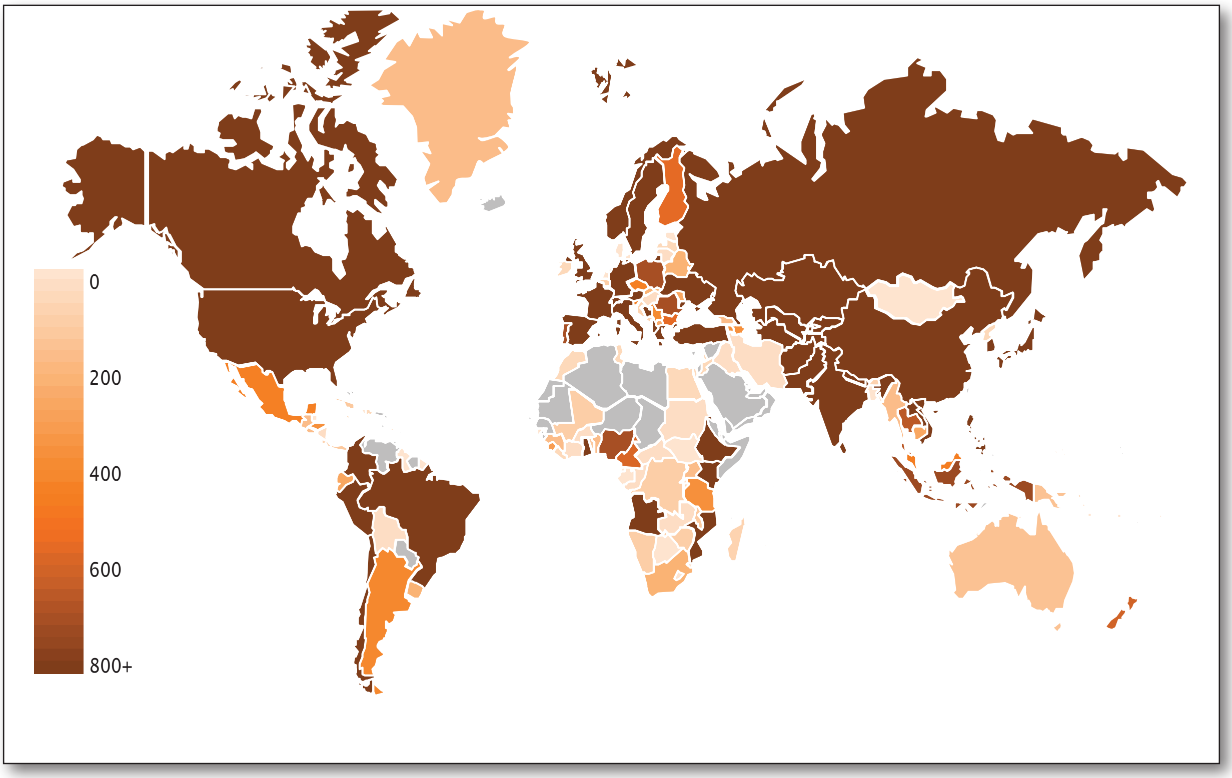
SHP installed capacity by country (MW)



Source: ICSHP

FIGURE 11

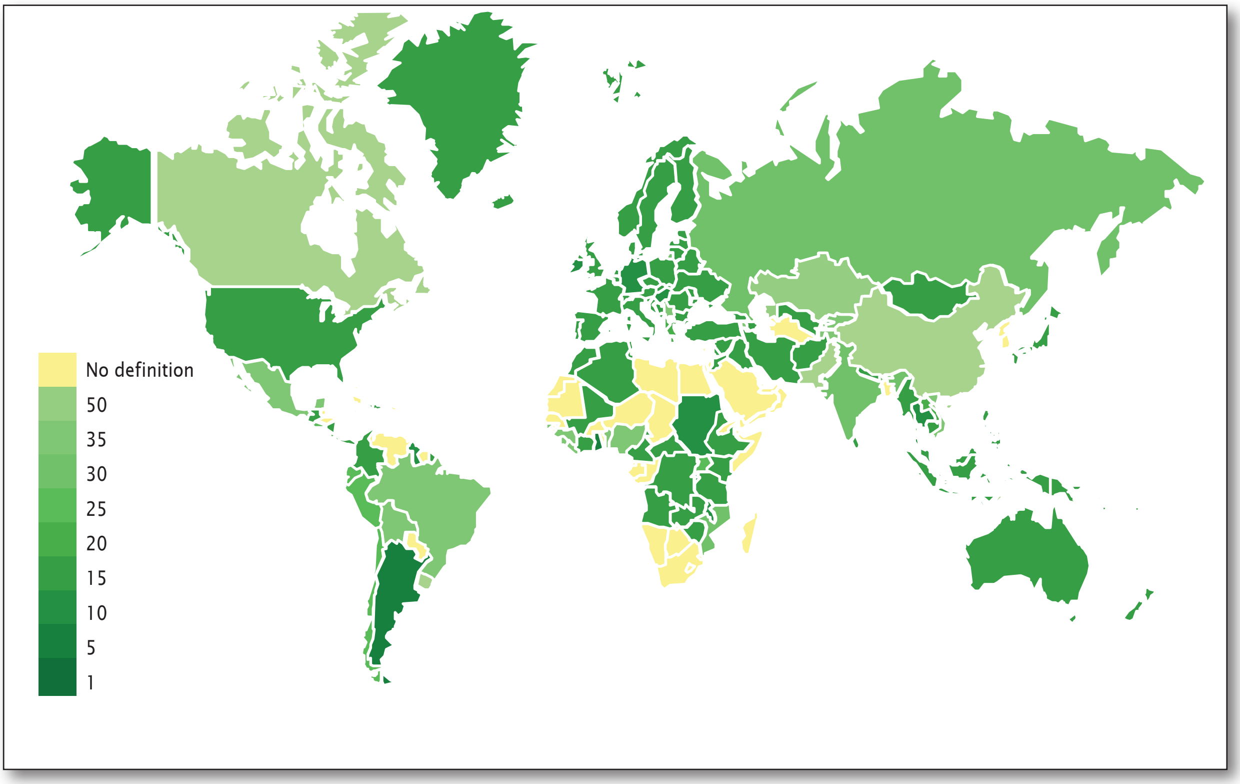
Identified SHP potential by country (MW)



Source: ICSHP

FIGURE 12

Definition of SHP by country (MW)



Source: ICSHP

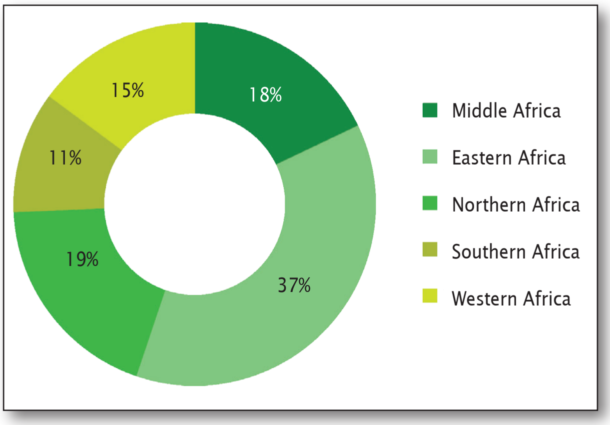
Africa

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, resulting in a large variance of SHP potential in the north and south as compared to the east and west of the continent (Figure 15).

The total SHP installed capacity for Africa is 580 MW and the total estimated potential is 12,197 MW. This indicates that approximately 5 per cent has so far been developed.

FIGURE 13

Share of installed SHP capacity in Africa (%)



Eastern Africa has the highest installed capacity and potential for SHP in the continent, followed by the Western and Middle Africa regions. Northern Africa has the highest electrification rate, but due to climatic conditions, it has low potential for hydropower. Southern Africa has the lowest installed capacity, the vast majority of which is located in South Africa.

Of the 45 countries in the region, many have some form of renewable energy policy, while 10 countries have established FITs relating to SHP.

FIGURE 15

Potential SHP capacity by country in Africa (MW)

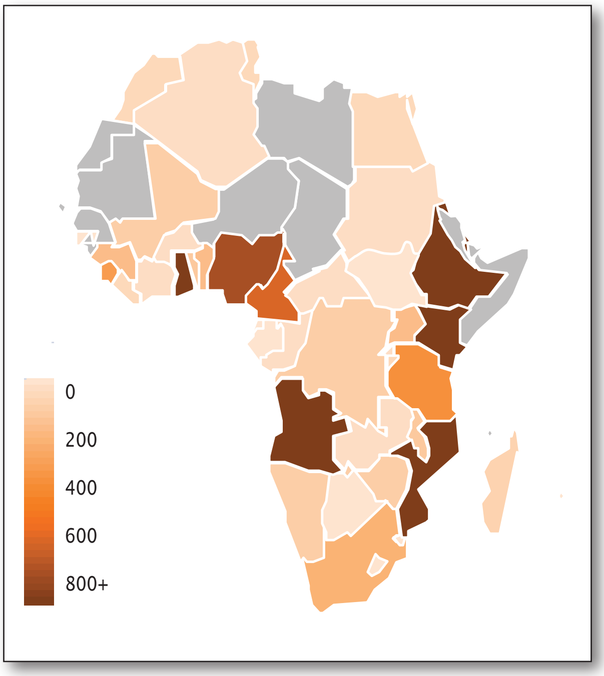


FIGURE 14

Installed SHP capacity by country in Africa (MW)

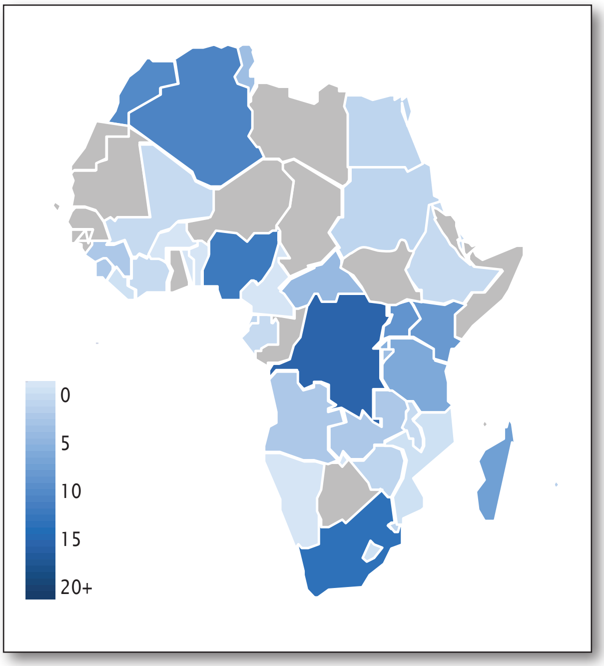
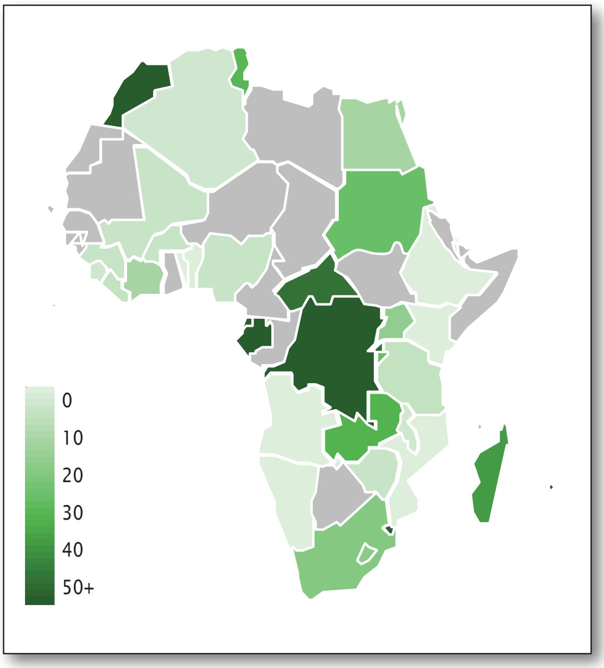


FIGURE 16

Developed SHP by country in Africa (%)



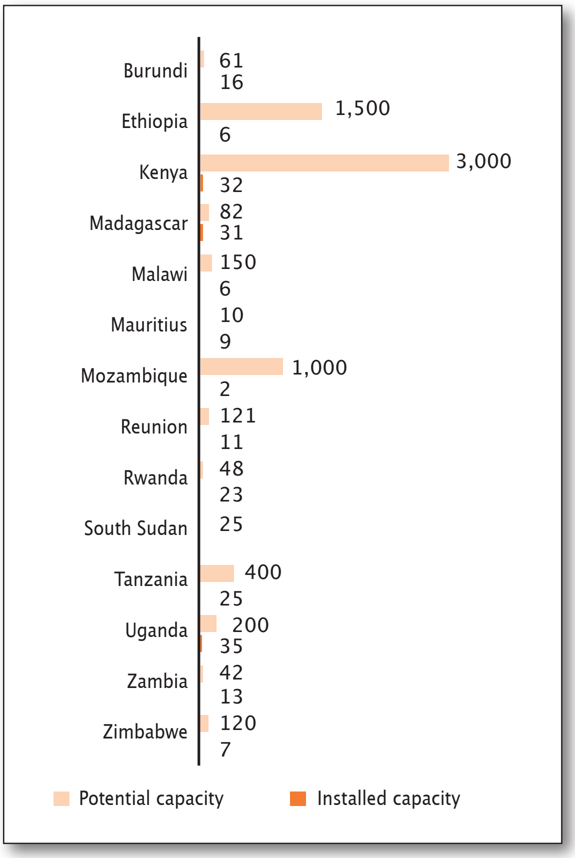
Eastern Africa

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

The Eastern Africa region has the highest overall potential for SHP in the African continent. It is home to the Great Lakes region as well as the White Nile basin, the Congo River basin, among others. In Burundi, Ethiopia, Malawi, Mozambique, Uganda and Zambia, large hydropower provides the vast majority of national electricity generation.

FIGURE 17

SHP capacities in Eastern Africa (MW)



Of the total SHP potential of 6,759 MW, the combined SHP installed capacity in the region is only 216 MW. Uganda has the highest installed capacity, with 35 MW, while South Sudan currently has no installed capacity. With only 3 per cent of SHP potential having been developed, countries such as Kenya and Ethiopia have significant potential estimated at 3,000 MW and 1,500 MW respectively.

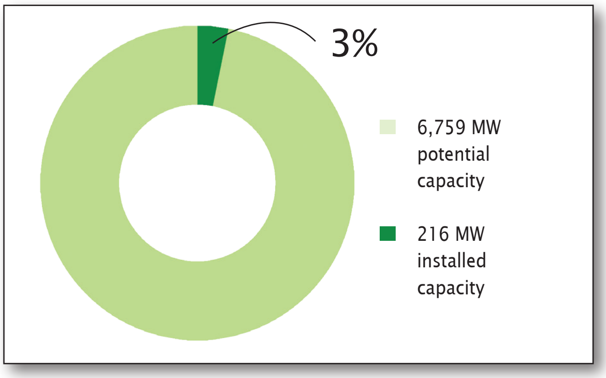
Most countries in the region are member states of the Common Market for Eastern and Southern Africa (COMESA), several are participating members of the East African Power Pool (EAPP). Renewable energy policies are either already in place or being implemented in the near future. Ethiopia and Malawi are expected to implement FITs while Kenya, Mauritius, Rwanda, Tanzania and Uganda have FITs in place, marking Eastern Africa as the sub-region with the most FIT policies.

SHP development has been relatively slow. So far, Madagascar, Mauritius, Mozambique, Tanzania, Uganda and Zimbabwe have moderately increased their share of SHP in the generation mix.

More extensive hydrological data and feasibility studies are needed in several countries, including Burundi, Tanzania and Zambia. In collaboration with the World Bank, Madagascar will publish a hydropower atlas by the end of 2016.

FIGURE 18

Developed SHP potential in Eastern Africa (%)



Barriers to SHP development include the costs of infrastructure development, including transmission lines and roads to SHP sites; lack of long-term financial solutions from local banks; and a need for capacity building in regards to maintenance and operation of SHP plants.

Middle Africa

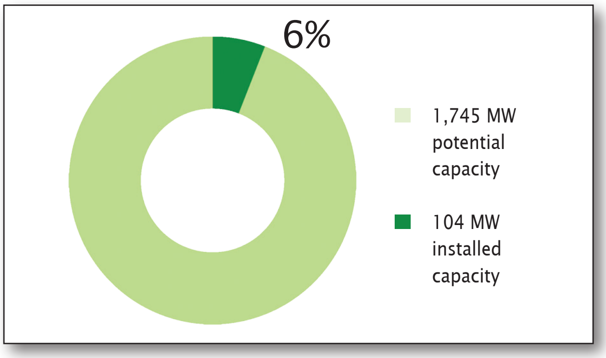
Angola, Cameroon, Central African Republic (CAR), Democratic Republic of the Congo (DRC), Congo, Equatorial Guinea, Gabon and Sao Tome and Principe

Like much of the African continent, the Middle Africa region has a large amount of undeveloped SHP potential. The Democratic Republic of the Congo has the highest installed SHP capacity at 56 MW, or over half of its potential, although further feasibility studies should reflect the increase of the number of potential sites. Angola has the highest SHP potential at approximately 860 MW, yet less than 2 per cent has been developed. While Equatorial Guinea and Gabon are likely to have considerable potential, accurate data are unavailable, giving the false impression that there is no SHP left to develop in the country. Overall, about 6 per cent of the regional SHP has been developed, marking a decrease in percentage from *WSHPDR 2013*, largely due to the increase in SHP potential in Angola.

The overall hydropower resources of Middle Africa are enough to supply the entire continent, and progress is being made to develop large-scale hydropower resources in several countries.

FIGURE 19

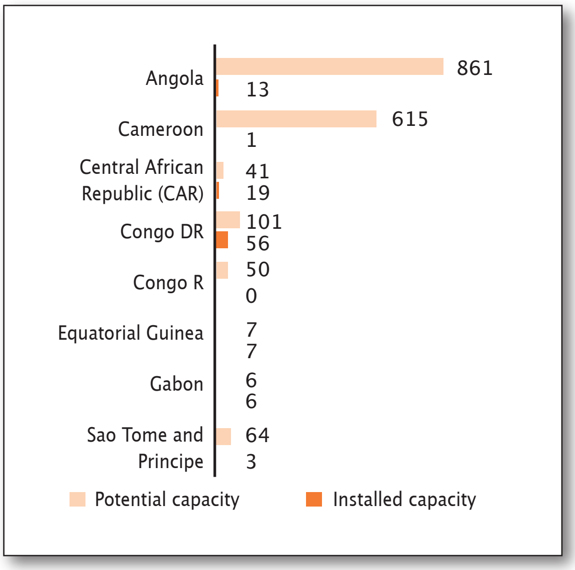
Developed SHP potential in Middle Africa (%)



However, all the countries in the region have very low electrification rates, which are significantly lower in the rural areas, with inefficient transmission networks compounding the issue. Moreover, most countries in the region lack formal policies for developing the SHP sector, hindering not only the construction of SHP projects but also progress in rural electrification.

FIGURE 20

SHP capacities in Middle Africa (MW)



More data are needed for the Central African Republic, Congo, Equatorial Guinea and Gabon to accurately determine their SHP potentials. More crucial to the overall renewable energy development is the need to establish transparent legal frameworks for investment in the energy sectors of most countries in the region.

Northern Africa

Algeria, Egypt, Morocco, Sudan and Tunisia

Partly attributable to the dry climate and limited water resources in Northern Africa, hydropower in general is not a primary source for generation, particularly in Algeria and Tunisia, where hydropower represents about 1 per cent of overall generation. The estimated SHP potential in Northern Africa is limited at 225 MW, one of the lowest in the world, with 112 MW already developed. This indicates that approximately half of the potential is considered developed. It should be noted that this percentage is lower than that indicated in the *WSHPDR 2013*, due to the SHP potential increases in Egypt and Sudan.

FIGURE 21

Developed SHP potential in Northern Africa (%)

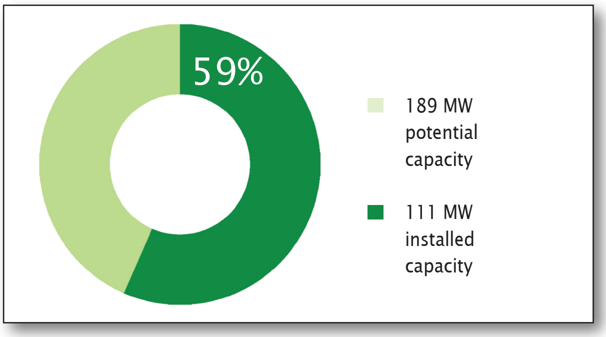
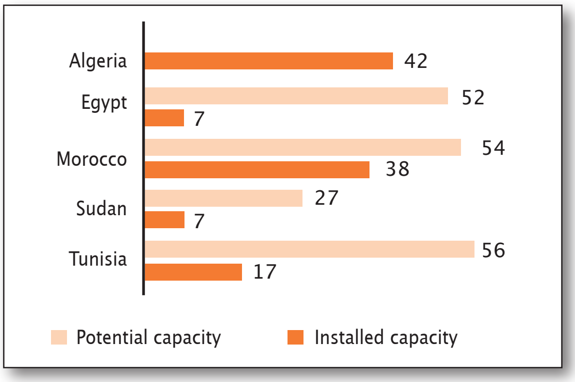


FIGURE 22

SHP capacities in Northern Africa (MW)



Morocco is the only country in the region with robust policies regarding SHP development and is currently constructing an SHP project of 15 MW. Conversely, due to climatic conditions and water shortages, Algeria has planned to cease hydroelectric generation in favour of utilizing all water resources for irrigation and water supply. Most countries of the region have opted for wind and solar power as alternatives to fossil fuels.

Southern Africa

Botswana, Lesotho, Namibia, South Africa and Swaziland

SHP in Southern Africa is dominated by South Africa, which comprises 80 per cent of the region's combined installed capacity and 63 per cent of the estimated potential. Aside from South Africa, which has had a considerable effect on the regional development of the sector, SHP potential is rather limited.

The combined installed capacity of the region is 62.5 MW and potential is 392 MW. This indicates that 16 per cent has so far been developed. Swaziland has so far developed half of its SHP potential. In doing so, it had the largest increase in installed capacity, while Botswana still has no SHP. In Lesotho and Namibia, SHP capacity has remained unchanged.

FIGURE 23

SHP capacities in Southern Africa (MW)

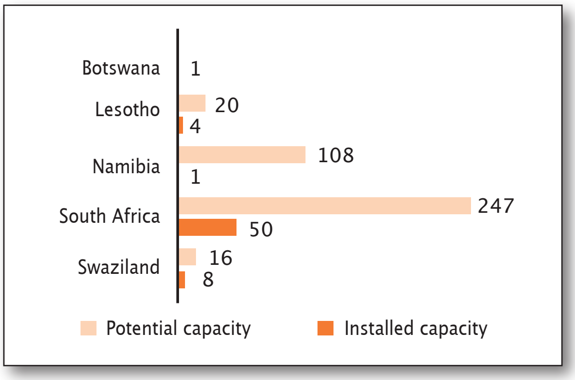
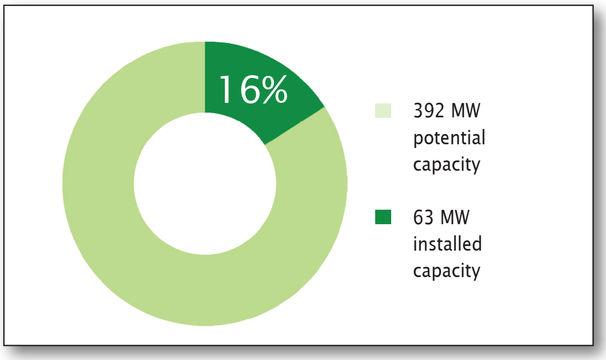


FIGURE 24

Developed SHP potential in Southern Africa (%)



Coal and large hydropower remain the chief sources of electricity generation in the region, while solar has the most abundant potential of small-scale renewable sources. Renewable energy policies and national plans reflect this, and large hydropower and solar power will continue to be dominant renewable energy sources for several of the countries in the region. As such, the SHP sector is relatively underdeveloped with the exception of South Africa.

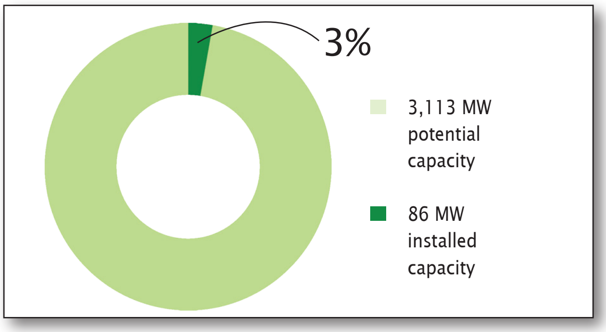
Western Africa

Benin, Burkina Faso, Cote d'Ivoire, Gambia, Ghana, Guinea, Liberia, Mali, Nigeria, Senegal, Sierra Leone and Togo

As with much of the African continent, Western Africa can be characterized as having considerable SHP potential but with limited development. Ghana and Nigeria, for example, have estimated potential capacities of 1,245 MW and 735 MW respectively. However, only 6 per cent of the potential in Nigeria has so far been developed, and there is currently no SHP in Ghana.

FIGURE 25

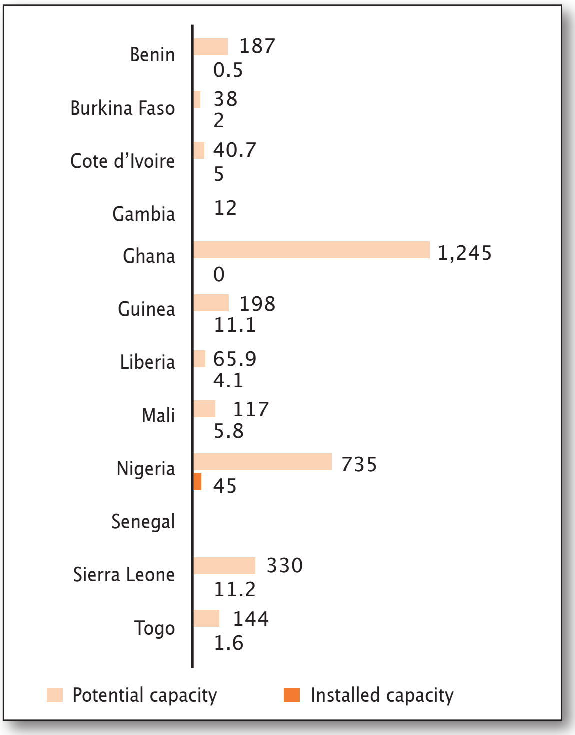
Developed SHP potential in Western Africa (%)



The region has the second-highest SHP potential in the continent, at 3,113 MW. Yet the installed capacity is the second lowest, with only 86.1 MW in operation. This indicates that 3 per cent of the total potential has been developed overall.

FIGURE 26

SHP capacities in Western Africa (MW)



Nigeria has the highest installed capacity, at 45 MW, while Sierra Leone has demonstrated the largest increase. If current long-term SHP projects are carried out, the region stands to triple its installed capacity of SHP.

Although the region has witnessed slower growth in the SHP sector compared with other regions in Africa, Western Africa has the second-largest potential in Africa. Combined with the planned projects and development goals set forth by the Economic Community of West African States (ECOWAS), the region could very well see an upswing in SHP development.

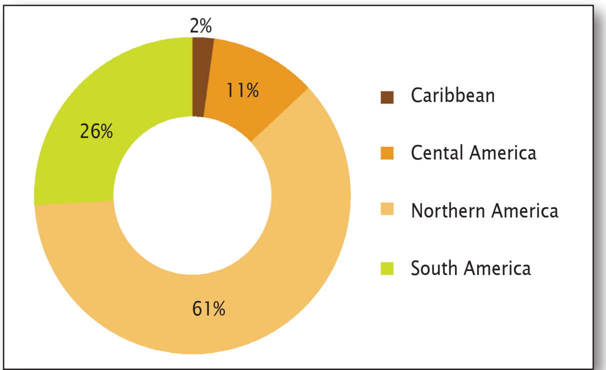
Sources: All data for this region are referenced in the respective regional summaries and country chapters.

Americas

The Americas consist of four regions: the Caribbean, Central America, Northern America and South America. Northern America and South America dominate the SHP landscape in all of the Americas through Brazil, Canada and the United States of America, with these three countries having an extensive amount of installed and potential SHP capacities. Countries in the Caribbean and Central America regions, with the exception of Mexico, have significantly less estimated potential. However, it is likely that further studies in the future could reveal a greater potential in the Caribbean and Central America.

FIGURE 27

Installed SHP capacity in Americas (%)



The total SHP capacity in the Americas is 14,702 MW while the total estimated potential is at least 86,868 MW for up to 50 MW. For capacities less than 10 MW, the installed capacity is 7,863 MW and potential is 44,162 MW. Some countries with enormous expected SHP potential have not had feasibility studies to determine their exact potential capacity. Mexico, for example, is a country that is suspected to have a large SHP potential but there have been no studies conducted to determine the country's true SHP potential. According to the available data, at least 17 per cent of the SHP potential capacities has been developed in the Americas.

Of the 30 countries in the region, four have established FITs relating to SHP. These four countries are Canada, the United States of America (though in the USA FITs are implemented only by some states), the Dominican Republic and Grenada.

The Caribbean, Central America and South America have experienced growth within the SHP sector, with their total installed capacities increased by 38 per cent, 43 per cent and 18 per cent respectively, since *WSHPDR 2013*. Many of the countries in these four regions have also established policies that incentivise the SHP sector. The Americas as a whole, however, still face barriers to developing SHP. This is mainly due to the high upfront costs of SHP plants, lack of regulatory policies in many of its 30 countries and social resistance to hydropower as it is perceived by many local populations as a technology that degrades the environment and destroys ecosystems.

FIGURE 28

Installed SHP capacity by country in the Americas (MW)

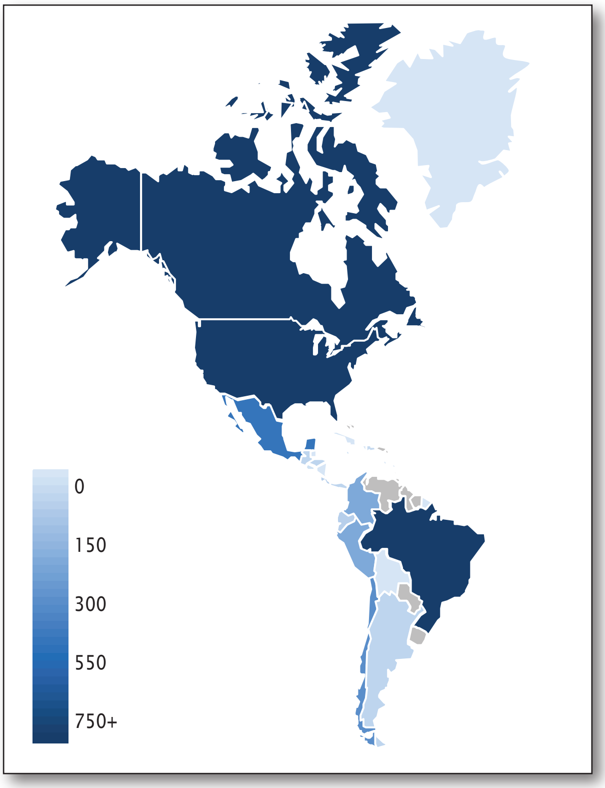


FIGURE 29

Potential SHP capacity by country in the Americas (MW)

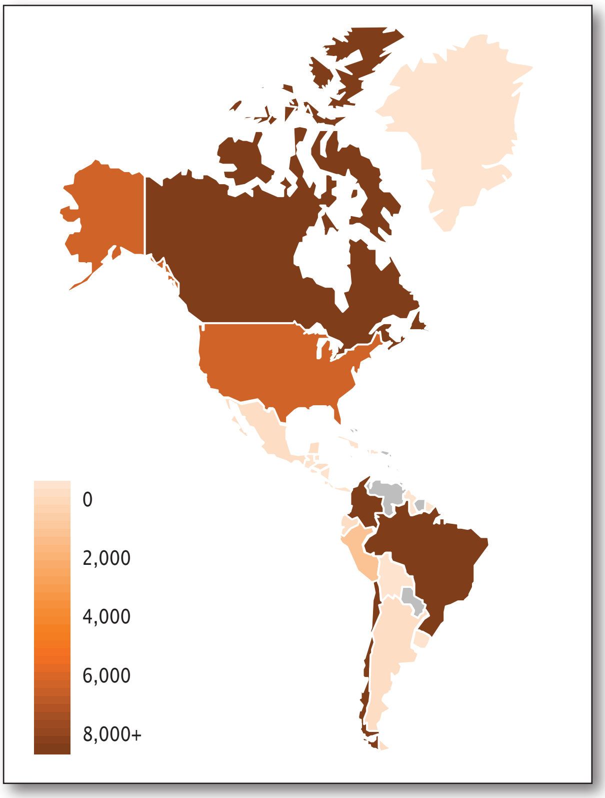


FIGURE 30

Developed SHP by country in the Americas (%)

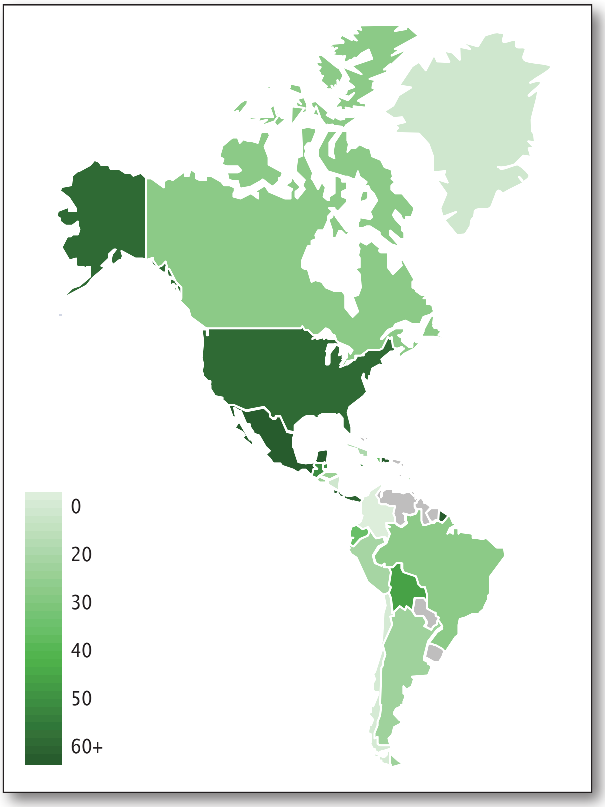


FIGURE 31

Developed SHP potential in the Caribbean

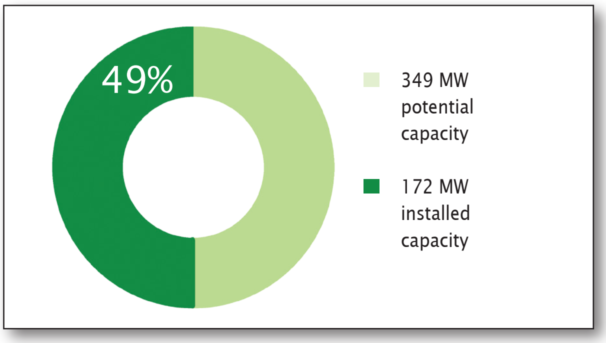
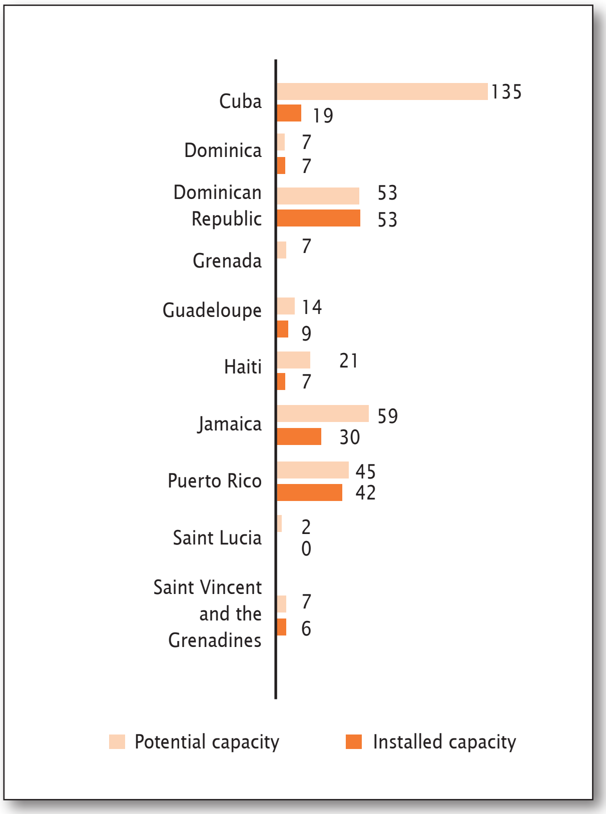


FIGURE 32

SHP capacities in Caribbean (MW)



Caribbean

Cuba, Dominica, Dominican Republic, Grenada, Guadeloupe, Haiti, Jamaica, Puerto Rico, Saint Lucia and Saint Vincent and the Grenadines

The Caribbean has one of the lowest levels of installed capacity in the world, placing it the sixth region with the lowest SHP installed capacity, with just 172 MW installed. There is at least a total potential of 349 MW in the region. However, It should be noted that this Report was not able to access the SHP potential for the Dominican Republic and Dominica. Therefore, the installed capacity of these two countries was used as the minimum threshold for the potential capacity. In the regional report, the potential capacities of the Dominican Republic and Dominica were recorded as not available and thus the total potential in the region was calculated as 290 MW. Nonetheless, the installed and potential capacities estimates indicate that at least 49 per cent of SHP has so far been developed in the Caribbean. Of the 10 countries in the region, two have established FITs—the Dominican Republic and Grenada.

All countries in the region are dealing with high costs and environmental degradation linked to their heavy reliance on fossil fuels. The cost of electricity imports and/or fossil fuels for the electricity sector is far too high for the countries to sustain. Thus, all countries have a national plan aimed at diversifying their energy mix. Within those national plans, which have set a timeline of a number of years to minimize their dependence on fossil fuel, there is a large focus on developing wind, solar, geothermal and biofuel power plants. Only a few countries have SHP policies within their national framework—Cuba, Dominica, the Dominican Republic, Jamaica, and Saint Vincent and Grenadines.

The Caribbean has seen development of the SHP sector in the form of feasibility studies—mainly studies on existing SHP plants. The countries that have conducted these feasibility studies are Jamaica, Haiti, Dominica, the Dominican Republic and Cuba. The Dominican Republic is the only country that has significantly increased its SHP capacity since *WSHPDR 2013*, from a total installed capacity of 15.4 MW to 52.5 MW.

Overall, the region's greatest challenge within the SHP sector is the lack of environmental conditions needed for efficient SHP plants and/or the lack of field studies needed to establish the true SHP potential of the islands. The Caribbean also generally lacks a systematic framework needed for the SHP sector. Mainly, these institutional problems arise from the lack of FITs and other incentives and/or supporting mechanisms, difficulties in land acquisition, energy generation monopolies and the absence of appropriate protocols to facilitate contracts.

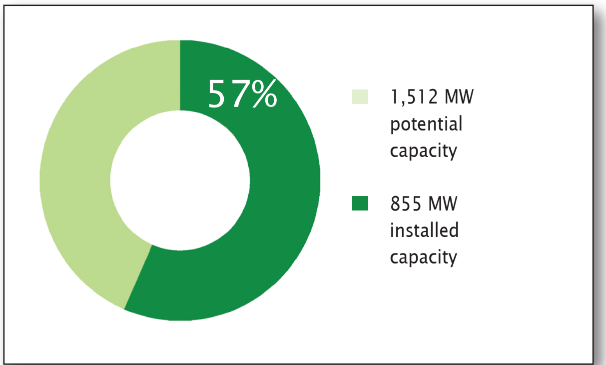
Central America

Belize, Costa Rica, El Salvador, Guatemala, Honduras, Mexico, Nicaragua and Panama

Mexico dominates Central America's SHP landscape, with approximately 55 per cent of the total installed capacity. In total there is 855 MW of installed SHP capacity, with a total potential of at least 1,512 MW. It should be noted that the potential of SHP for Mexico is so far unknown but it is believed to be vast. The region has developed at least 57 per cent of its SHP potential. However, it has done this without the use of FITs, as none of the eight countries have established FITs for SHP. It should be noted that the percentage of developed SHP does not include potential for Mexico, indicating a higher rate than what was reported in *WSHPDR 2013*.

FIGURE 33

Developed SHP potential in Central America (%)

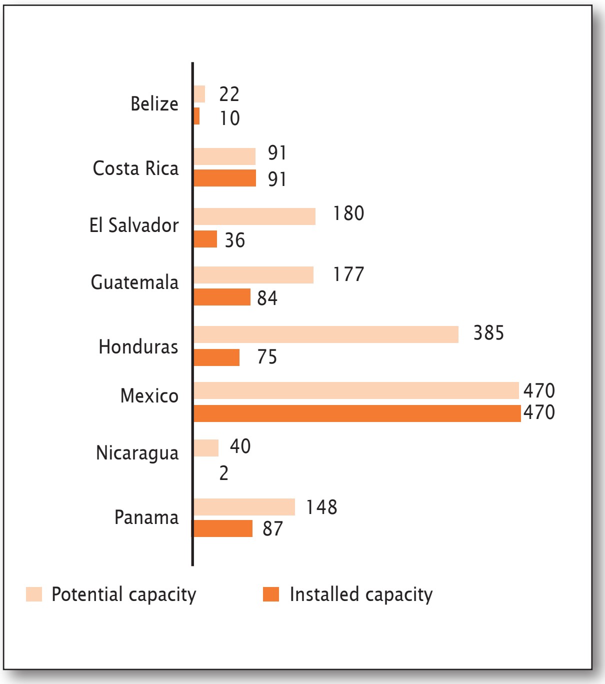


The countries of Central America have taken great steps to improve their renewable energy sector, which includes SHP. Specifically, Mexico and Honduras have taken measures to liberalize their electricity sectors, allowing for private investment to take place, while promoting investment in renewable energy resources such as SHP.

All eight countries have also established some sort of national framework to reduce carbon emission in the region, with Mexico and Costa Rica taking the most proactive steps. In 2015, Mexico presented to the United Nations Framework Convention on Climate Change (UNFCCC) its goals to reduce greenhouse gasses by 22 per cent by 2030, while Costa Rica has committed to focusing on becoming carbon neutral by 2021.

FIGURE 34

SHP capacities in Central America (MW)



Despite Central America taking proactive steps to improve its SHP sector, the countries still have a number of barriers that have to be addressed in order for SHP to fully develop its potential in the region. These barriers include the lack of FITs, which are essential to attracting financial investment for SHP, and the lack of concrete policies specifically designed for the development of SHP.

More specifically, Belize has unregulated markets and absence of energy and electricity standards; Guatemala constantly faces land-right issues with its population; and Costa Rica has limits on private investor participation in energy generation. Lastly, there is also the lack of reliable river flow data and detailed hydropower potential inventories that are essential for developing the SHP sector.

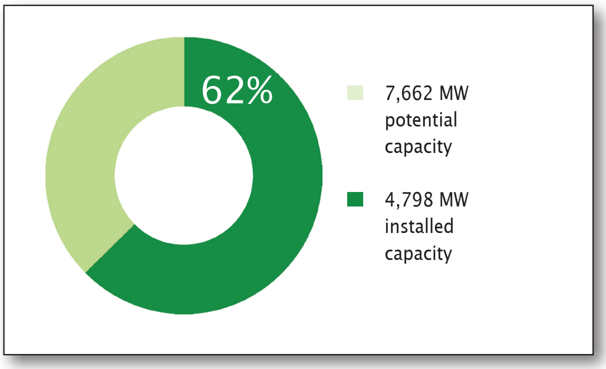
Northern America

Canada, Greenland, and the United States of America (USA)

Greenland has some SHP installed capacity and potential but it is dwarfed in comparison to the two largest countries in the region—Canada and the United States of America (USA). Despite only these three countries in the region possessing SHP capacity and potential, the region boasts the fourth-highest estimated SHP potential capacity in the world (up to 50 MW). However, it has developed 62 per cent of its less than 10 MW potential, with a total SHP installed capacity of 4,798 MW and potential capacity of 7,662 MW.

FIGURE 35

Developed SHP potential in Northern America (%)

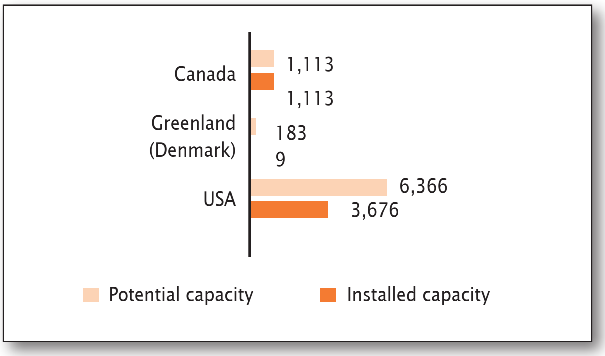


It should be noted that the definition of SHP by Canada includes all plants with an installed capacity of 50 MW or less. Therefore some reporting might include higher statistics for regional and country capacities. The less-than-10 MW potential for Canada was derived from the currently installed SHP; it is expected to be far higher, but it is at least 1,113 MW.

Both the USA and Canada have introduced FITs for SHP. However, due to the bureaucratic structure of the two countries, the tariffs are not nationwide, making their application variable according to state regulations.

FIGURE 36

SHP capacities in Northern America (<10 MW)



While the USA has implemented policies that promote SHP development, Canada and Greenland have yet to customize their policies towards SHP development. The lack of policies in Canada has much to do with its unique national strategy, which allows its provinces to develop policies with autonomy. This means that SHP development varies across jurisdictions. Greenland, on the other hand, can attribute its lack of policies to its focus on developing large hydropower as opposed to SHP. The USA, however, has had the Department of Energy (DOE) driving research and development efforts for SHP as part of its Water Power Program. The DOE also supports the National Hydropower Asset Assessment Program (NHAAP), which is an integrated water infrastructure information platform for the management and policy planning of sustainable hydroelectricity generation.

The region still faces many barriers to SHP development. In general, the greatest barriers are the high upfront costs of SHP and the technical requirements of grid interconnection. Furthermore, each country has its own set of challenges when it comes to SHP development. In Greenland, the main obstacles come from the transportation costs of electricity and SHP equipment. This is mostly due to the country's landscape, as many of the towns and settlements in Greenland are not connected by road. In Canada, the obstacles have been attributed to the lack of transboundary cooperation between upstream and downstream jurisdictions. The unique national strategy that allows its provinces to develop policies with autonomy has also led to a fragmented approach in almost all aspects of the energy sector due to the electricity policy and renewable energy targets of individual provinces. However, despite this systematic barrier, a hydro renaissance is possible in Canada, with hydro resources playing a larger role in the quest for a more renewable, sustainable, stable and economical power system. Lastly, barriers in the USA include a lack of comprehensive information regarding suitable sites and conduit hydropower opportunities, a lack of standardized technology, and state and local regulatory challenges, including regulatory issues associated with water quality certifications and environmental requirements.

South America

Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, French Guiana, Paraguay, Peru, Uruguay and Guyana

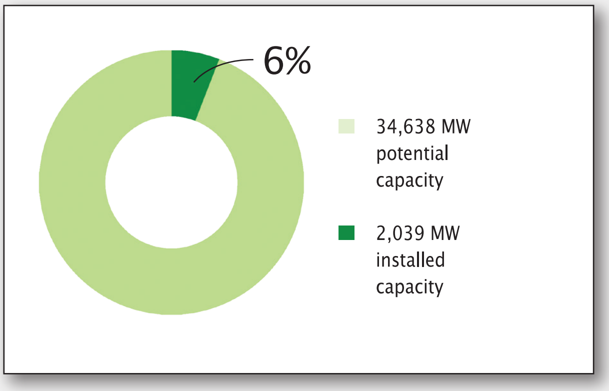
South America has the second-highest level of installed SHP capacity in the world. Brazil, Chile and Colombia combined account for 96 per cent of the region's total potential. However, due to the comparatively limited installed capacities, the region has the second-highest level of undeveloped potential in the world, with 63,463 MW of potential up to 50 MW, but only 6,783 MW of it being the total installed capacity (including plants up to 30 MW in Brazil). This indicates that only about 10 per cent has been developed. For SHP of less than 10 MW, the numbers are significantly reduced, except for the potential for Brazil being unknown, South America has at least 2,039 MW regional installed capacity and at least 34,638 MW potential capacity.

South America has experienced a significant increase in the total SHP installed capacity and has accomplished the increase without FITs, as no country in the region has established FITs for SHP.

South America began developing SHP in 1970 with the purpose of increasing the electrification rate in small towns and feeding the national grids. The countries in South America that have actually developed specialized polices for SHP are Argentina, Bolivia, Brazil, Chile, Colombia and Ecuador. Each of those countries has renewable energy policies that encourage and provide benefits for developing renewable energy projects that

FIGURE 37

Developed SHP potential in South America (%)

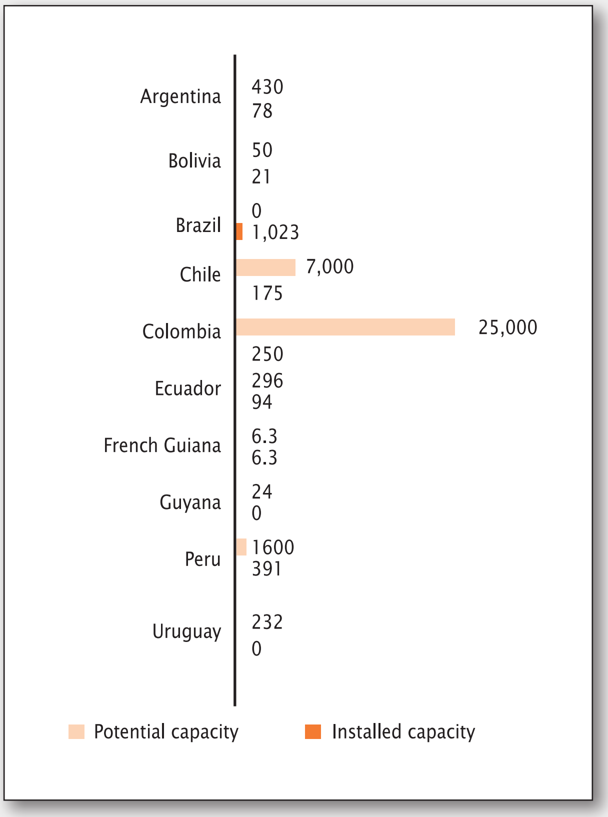


include small hydro schemes. Some of the benefits the countries have offered to incentivise SHP include exemption or reduction of taxes for importing SHP equipment or building SHP plants as well as power purchase agreements that secure the energy purchase price in a mid- or long-term agreement. This allows investors to pay for the generation costs and receive an acceptable investment return rate.

Despite such attractive incentives in some of the countries, the region still faces a number of barriers to SHP. Generally, the financial resource constraints due to limited availability of local finance institutions or local financial policies pose a huge barrier for the governments in the region.

FIGURE 38

SHP capacities in South America (MW)



There is also a social barrier related to the local population's perception of hydropower—which tends to be negative—and a lack of information regarding the impacts and benefits of small hydro projects in particular. This hinders the governments' ability to establish regulatory frameworks, which in turn may lead to cancellation of projects. Lastly, the region has poor quality of hydrological, climate and statistical data, especially for remote areas far from the main cities where the locations are suitable for SHP projects.

Sources: All data for this region are referenced in the respective regional chapters.

Asia

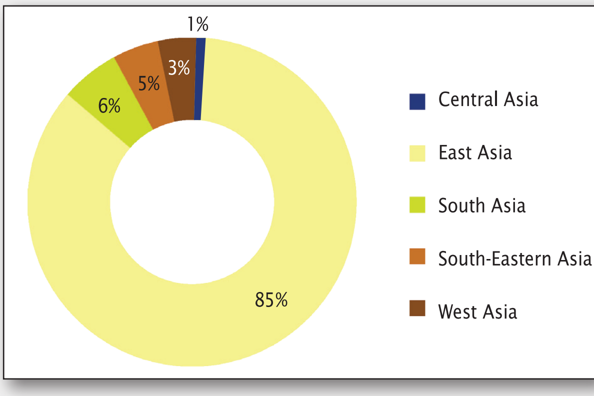
Asia has vast SHP resources. However, they are unevenly distributed across the continent (Figure 41). Almost 80 per cent of the discovered SHP potential is concentrated in just three countries of the continent—China, Tajikistan and India (using data for local definitions of SHP). The countries with the lowest SHP potential are Bangladesh, Timor-Leste and Saudi Arabia.

The total installed SHP capacity of Asia is 50,729 MW and the total estimated potential is 120,614 MW (for up to 10 MW). This indicates that approximately 42 per cent has so far been developed. SHP accounts for 16 per cent of the continent's total installed hydropower capacity and 3 per cent of total electricity generating capacity. The installed SHP capacity of the continent has been increasing over the past few years.

As already noted, China dominates not only the Asian SHP landscape but also in the world. Within Asia, China accounts for approximately 78 per cent of the installed capacity and 53 per cent of the total potential capacity.

FIGURE 39

Share of installed SHP capacity in Asia (%)



Eastern Asia has the highest installed capacity and potential for SHP in the continent. Central Asia has the lowest installed and potential capacities in the continent.

FIGURE 40

Installed SHP capacity by country in Asia (MW)

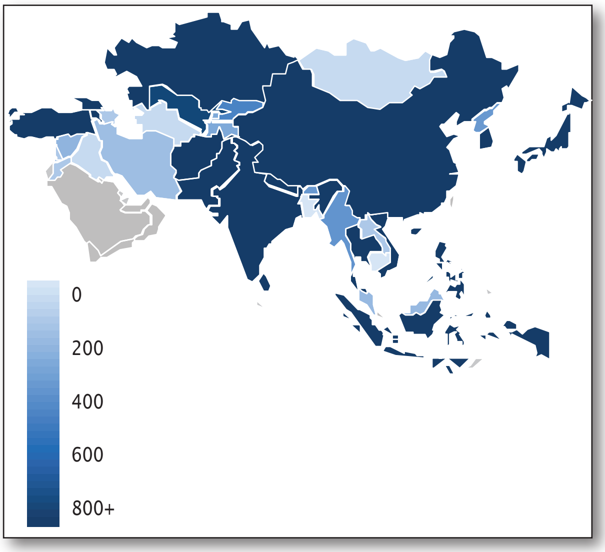


FIGURE 42

Developed SHP by country in Asia (MW)

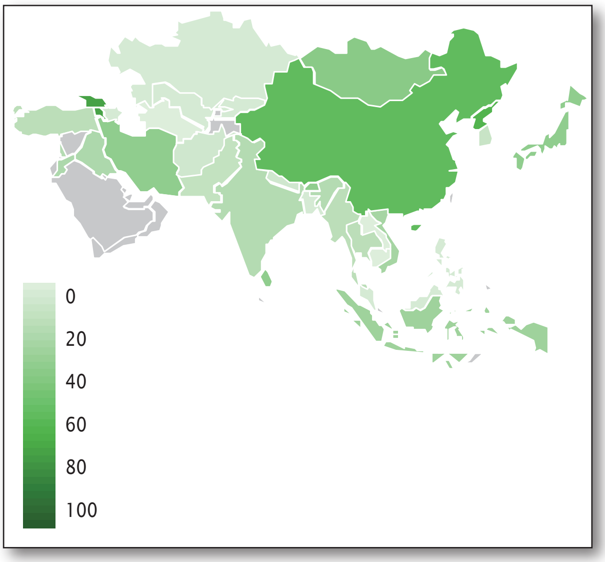
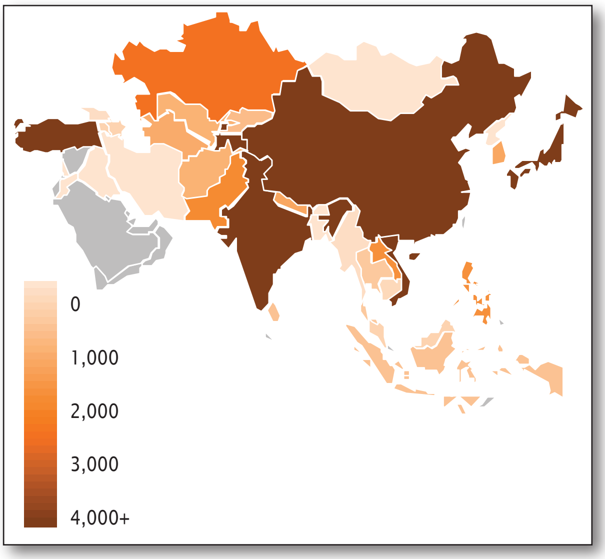


FIGURE 41

Potential SHP capacity by country in Asia (MW)



SHP development is one of the priorities for countries in Asia that possess potential for further development. The key motives for developing SHP in the continent are to decrease dependence on fossil fuels, thus mitigating environmental problems; decrease dependence on energy imports; and improve access to electricity, especially in rural areas.

Of the 36 countries in the continent covered in this Report, many have some form of renewable energy policy while 22 have established FITs related to SHP.

The barriers to SHP development vary across the continent. The major issues that complicate SHP development include the lack of skilled personnel and local technologies, limited financial resources, low electricity tariffs, water scarcity and limited data.

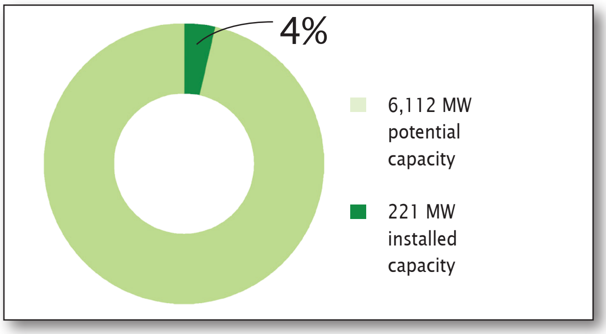
Central Asia

Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan, Uzbekistan

Installed capacity in Central Asia is relatively low. However, there remains a large amount of potential capacity available to be developed. Kazakhstan has the highest installed capacity, with 78 MW, whereas Tajikistan has the highest potential capacity, with 30,000 MW (up to 30 MW). Total installed capacity in the region is just 221 MW, while potential is considerable with an estimated 6,112 MW, indicating that just 4 per cent has so far been developed.

FIGURE 43

Developed SHP potential in Central Asia (%)

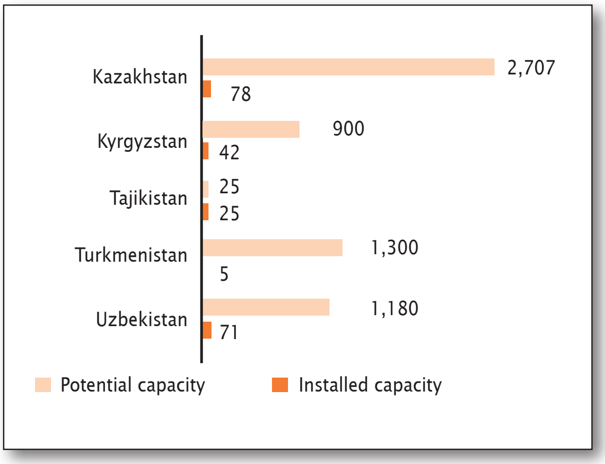


Hydropower resources are unevenly distributed among the countries, which were compensated during the Soviet era through the Central Asia Integrated Power System that connected all the countries into one single power system. After the collapse of the Soviet Union, each country established its own electricity system. However, the countries agreed to maintain parallel operations.

While Kazakhstan, Turkmenistan and Uzbekistan depend heavily on thermal power, hydropower is the main source

FIGURE 44

SHP in Central Asia (MW)



of electricity generation for Kyrgyzstan and Tajikistan. In general, the region has focused on the development of large-scale hydropower, with the share of SHP remaining rather low at 2 per cent of total hydropower installed capacity. Recently, SHP has attracted more attention of investors and governments, in particular for electrification of remote rural areas. According to the governments' plans, in the near future, 1,065 MW will be added to the regional SHP capacity, of which 51 per cent will be built in Kazakhstan.

A number of positive developments in sustainable energy have been observed in the region, with governments supporting renewable energy and energy efficiency through legislative and institutional reforms. All countries of the region, except Turkmenistan, have adopted legislation on renewable energy and have introduced FITs. The region demonstrates a growing interest in energy efficiency measures, which can be seen in Tajikistan and Kyrgyzstan by way of reducing their dependence on energy imports. Uzbekistan and Turkmenistan see it as a way to increase their fossil-fuel exports.

Barriers to SHP development in the region include the lack of affordable financial solutions from local banks, low awareness of the potential and possible applications of SHP, limited data on SHP potential, low electricity tariffs and low prices of traditional energy.

Eastern Asia

China, Democratic People's Republic of Korea, Japan, Mongolia and Republic of Korea

SHP in Eastern Asia is dominated by China, which constitutes 91 per cent of the region's total SHP installed capacity and 84 per cent of the potential. Japan and the Republic of Korea have comparatively smaller but still considerable SHP sectors. The total installed SHP capacity of Eastern Asia is 43,542 MW, whereas the potential is estimated at 75 GW, indicating that 58 per cent has been developed.

FIGURE 45

SHP in Eastern Asia (< 10 MW)

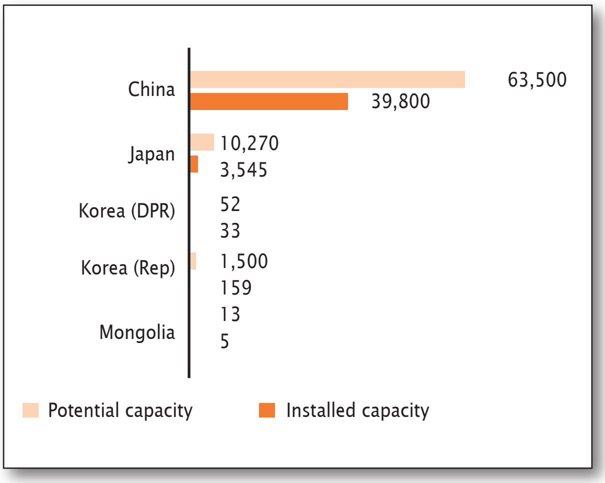
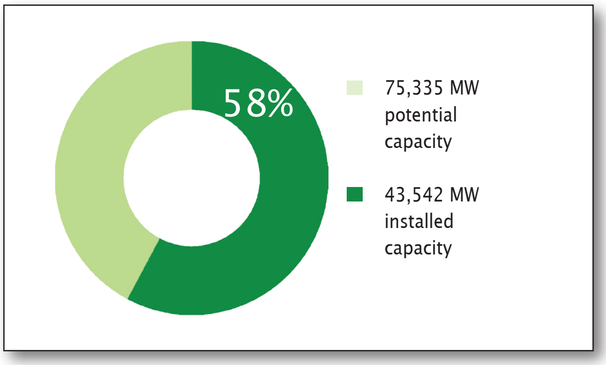


FIGURE 46

Developed SHP potential in Eastern Asia (%)



Fossil fuels remain the main source of energy in the region and nuclear power has a significant share in the energy mix of China, Japan and the Democratic People's Republic of Korea. This, combined with the escalating energy demand due to rapid economic growth and increasing population, contributes to the ever-growing emission of greenhouse gases and other air pollutants, which have a significant effect on air quality.

The countries in the region are trying to mitigate the environmental problems and encourage the development of renewable energies, including SHP. Besides, SHP is already being used by the governments in Eastern Asia to provide electricity to the rural population, contributing to rural development.

The region has a long history of SHP development. Currently, SHP accounts for 20 per cent of the region's total installed hydropower capacity and 4 per cent of the total installed electrical capacity. However, most countries in the region have limited expertise and manufacturing capacities for SHP. But China, on the contrary, possesses rich experience and expertise, which can be shared with its neighbouring countries.

SHP will see further growth in the region, with major developments planned in China and some projects in the Democratic People's Republic of Korea, Japan and the Republic of Korea. Mongolia, on the contrary, has no plans for further SHP development at present.

Three countries in the region—China, Japan and Mongolia—have introduced FITs, and all five countries in the region have adopted legislation on renewable energy.

The barriers to SHP development vary among the countries of the region. SHP development in Mongolia, the Democratic People's Republic of Korea, Japan and the Republic of Korea is hindered by the lack of skilled personnel and local technology. Mongolia and the Democratic People's Republic also lack financial resources required for SHP development. Moreover, more data are needed for an accurate assessment of their SHP potentials. Finally, SHP is not a priority for Mongolia and the Republic of Korea, which are focusing instead on large hydropower or solar and wind energy. China, on the other hand, experiences environmental difficulties as well as constraints associated with land compensation, labour cost and resettlement.

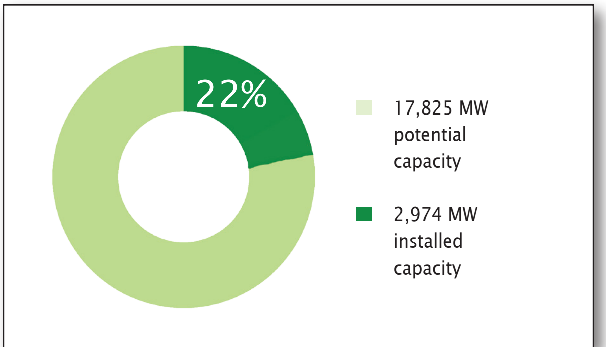
Southern Asia

Afghanistan, Bangladesh, Bhutan, India, Iran, Nepal, Pakistan, Sri Lanka

India dominates the SHP sector in Southern Asia, with approximately 71 per cent of total capacity (2,119 MW) and 67 per cent of the discovered potential (11,914 MW), up to 10 MW. At the other end of the spectrum, Bangladesh has low installed SHP and very limited potential due to its flat terrain. The SHP potential of Bhutan is currently unknown, but based on its total hydropower potential, it is expected to be very high.

FIGURE 47

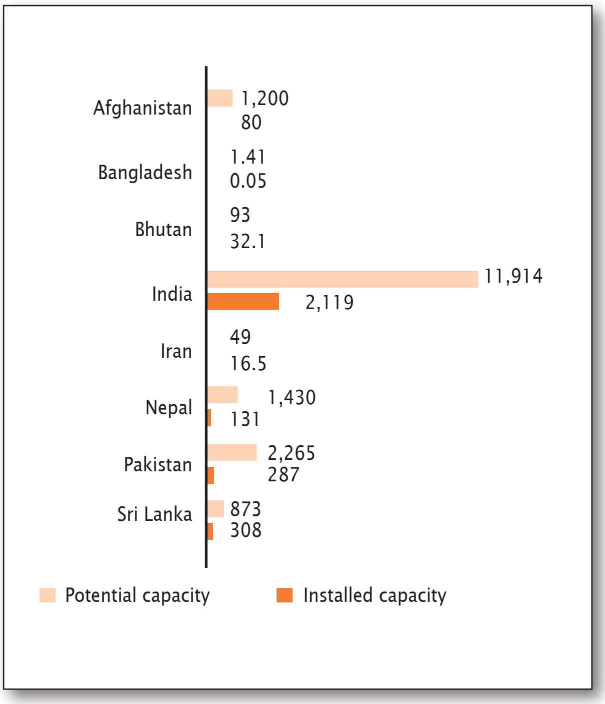
Developed SHP potential in Southern Asia (%)



The combined installed SHP capacity of the region is 2,974 MW and potential is 17,825 MW (less than 10 MW). This indicates that 17 per cent has so far been developed. The highest net increases in SHP installed capacity in recent years could be seen in Sri Lanka and Nepal.

FIGURE 48

SHP in Southern Asia (MW)



Hydropower is the main source of electricity generation in Afghanistan, Bhutan and Nepal. In particular, SHP accounts for 31 per cent of its total installed hydropower capacity in Afghanistan. In contrast, Bangladesh, India, Iran, Pakistan and Sri Lanka depend heavily on fossil fuels. However, hydropower still plays a significant role in the energy mixes of India, Iran, Pakistan and Sri Lanka. Overall, SHP in the region accounts for 8 per cent of total installed hydropower capacity and 1 per cent of total electrical capacity.

None of the countries in the region have reached 100 per cent electrification, with Afghanistan having the lowest rate in the region, at 43 per cent. Moreover, electricity grids have low efficiency and reliability with high losses and frequent blackouts. Therefore, providing universal access to electricity and reliable power supply remains an important challenge for countries in the region. SHP, including off-grid plants, has played an important role in the electrification of rural and remote areas and further development is planned for this purpose.

The Governments of India and Sri Lanka have put major focus on SHP development. Most countries in the region have developed regulatory frameworks to facilitate the development of renewable energies, including SHP. Five of them have introduced FITs.

Some barriers that hinder SHP development in the region are limited financial resources, lack of qualified specialists and technologies, limited studies on SHP potential and low electricity tariffs.

South-Eastern Asia

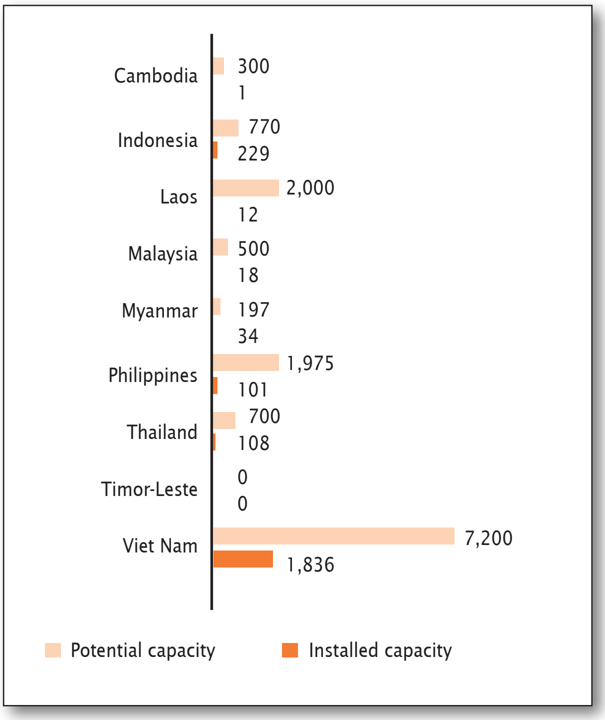
Cambodia, Indonesia, Lao People's Democratic Republic (Lao PDR), Malaysia, Myanmar, Philippines, Thailand, Timor-Leste, Viet Nam

The Report on South-Eastern Asia covers nine countries in the region. The combined total installed SHP capacity of these countries is 2,340 MW and estimated potential is 13,642 MW, indicating that 17 per cent has been developed. Viet Nam has the highest share of SHP capacity, at 78 per cent (1,836 MW), and also with the highest potential (7,200 MW).

The region has seen rapid economic and demographic growth in the last 25 years and, as a result, demand for electricity has increased substantially. The countries are faced with the need to develop their electric power capacities and infrastructure as well as to improve access to electricity, especially in rural areas. This creates an opportunity for SHP development in the region. Currently, SHP accounts for approximately 6 per cent of the region's total installed hydropower capacity and 1 per cent of total electricity generation capacity.

FIGURE 49

SHP capacities in South-Eastern Asia (MW)

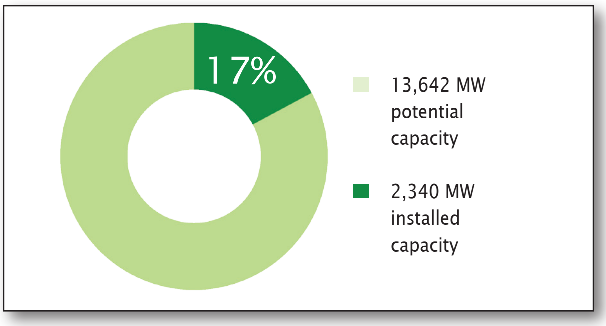


Fossil fuels still remain the chief source of electricity generation in the region. The countries in the region intend to decrease dependence on fossil fuels and develop renewable energies, which is reflected in their renewable energy policies and national plans. Lao PDR, Myanmar and Timor-Leste are currently without a law that would support the development of renewable energies. However, the Government of Lao PDR is in the process of drafting one, and Timor-Leste has a national programme for the development of renewable energies.

Hydropower plays an important role in the energy mixes of Cambodia, Myanmar and Viet Nam, and in Lao PDR, hydropower is the only source of electricity generation. The installed capacity of SHP in the region has been increasing, with most developments observed in Indonesia and Viet Nam. Conversely, the Government of Viet Nam has recently cancelled a number of SHP projects due to high social and environmental risks caused by poor planning and construction.

FIGURE 50

Developed SHP potential in South-Eastern Asia (%)



The development of SHP in the region is often hampered by a number of factors, including the high cost of projects due to the location of potential sites in remote areas, whereas access to financial resources is limited. Furthermore, although most countries have introduced subsidies for electricity generated from renewable energy sources, Cambodia, Lao PDR and Timor-Leste still lack FITs. Other challenges are the lack of technical knowledge and operational skills, the lack of standardized procedures and standards, and limited available data.

Western Asia

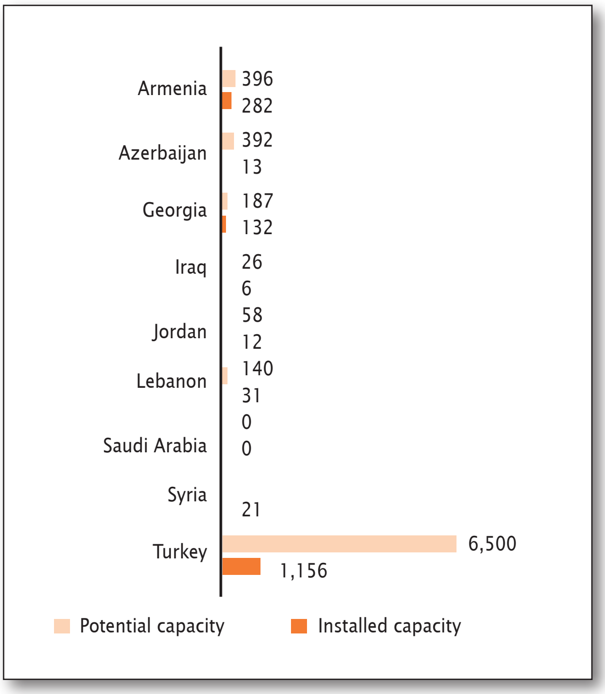
Armenia, Azerbaijan, Georgia, Iraq, Jordan, Lebanon, Saudi Arabia, Syrian Arab Republic, Turkey

The total installed SHP capacity of Western Asia is 1,653 MW and the estimated potential is 7,700 MW, indicating that 21 per cent has so far been developed, marking a significant increase from the figures reported in *WSHPDR 2013*, largely due to increases in installed capacities in Armenia and Turkey.

Much of Western Asia is located in a dry and desert climate. As a result, the region has the second-lowest SHP potential in the continent. Fairly considerable potential exists in the north-western parts, most notably in Turkey, which has an estimated potential of 6,500 MW or 84 per cent of the region's potential. Turkey is also the regional leader in terms of installed capacity with 1,156 MW, accounting for 70 per cent of the region's total.

FIGURE 51

SHP capacities in Western Asia (MW)

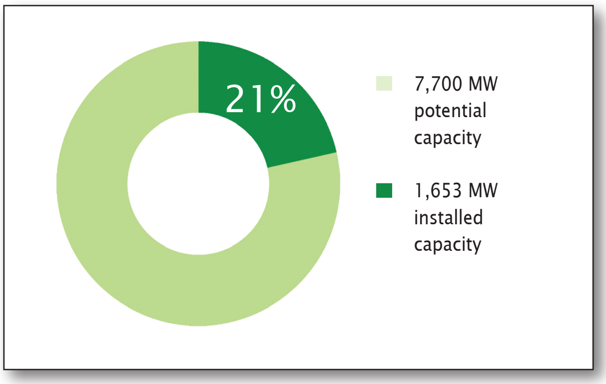


Most electricity in the region is generated from fossil fuels, with Georgia being the only country with the main share of hydropower in its energy mix. Armenia and Turkey are also highly dependent on hydropower. SHP accounts for 5 per cent of the region's total installed hydropower capacity and 1 per cent of total installed electricity generating capacity.

Armenia and Georgia have relatively developed SHP sectors. However, hydropower plants in these countries are prone to unreliable operation due to significant annual rainfall fluctuations. Azerbaijan has a significant SHP potential as well. However, only 3 per cent has so far been developed. Nonetheless, further SHP development is among the priority projects of the Government. In the rest of the region, there is limited interest in SHP due to water scarcity. Thus, Lebanon, Jordan and Iraq have relatively limited SHP potential, while Saudi Arabia has no SHP potential at all. The SHP potential of the Syrian Arab Republic is unknown.

FIGURE 52

Developed SHP potential in Western Asia (%)



The Caucasus countries and Turkey are seeking to further exploit their SHP potential, which is reflected in their policy frameworks. In other parts of the region, SHP development will remain rather limited due to water scarcity. Political instability is another major obstacle for SHP development in the region, especially in countries around the Middle East.

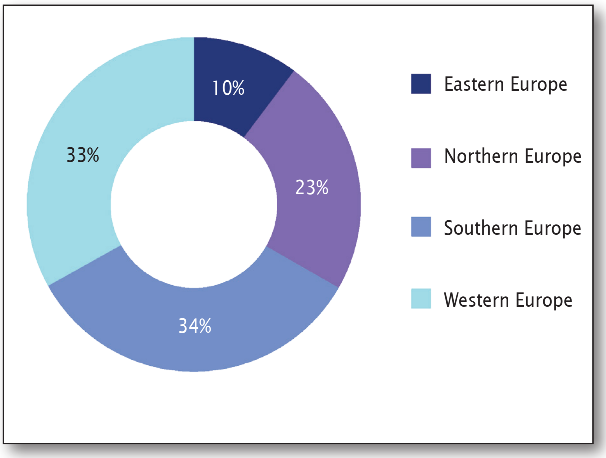
Sources: All data for this region are referenced in the respective regions.

Europe

Europe has a long history of SHP development, which has enabled the region to reach its highest rate of installed capacity. Europe, having a variety of climates and landscapes, fluctuates according to each sub-region in regards to SHP potential. Western Europe, for example, has great potential, with 85 per cent of its estimated potential already developed, while Northern Europe has very little SHP potential as much of it has already been fully developed.

FIGURE 53

Installed SHP capacity in Europe (MW)



The overall installed capacity in the region is 18,684 MW while the potential capacity is estimated at 38,943 MW. In comparison to *WSHPDR 2013*, this represents an increase in installed capacity of 5 per cent and an increase in potential capacity of 38 per cent. As of 2016, Europe has developed nearly 48 per cent of its SHP potential, with Western Europe reaching the world's highest SHP development rate, at 85 per cent.

Europe has the largest number of countries with established FITs for SHP; 28 out of the 39 countries

FIGURE 54

Installed SHP capacity by country (MW)

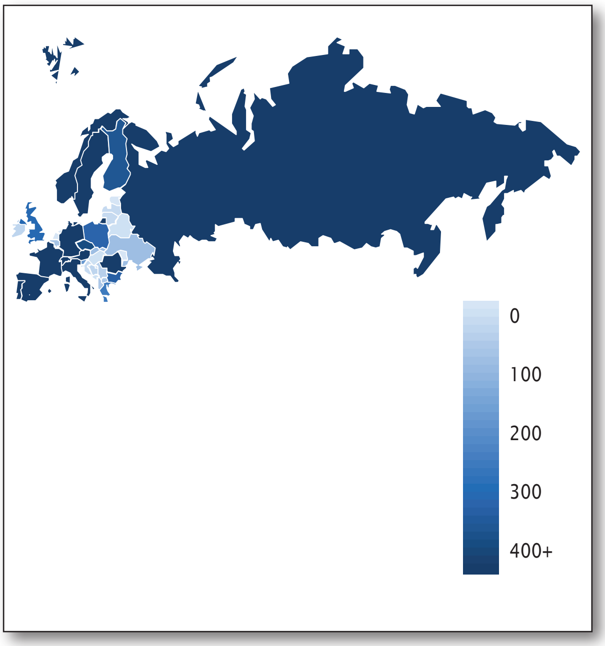
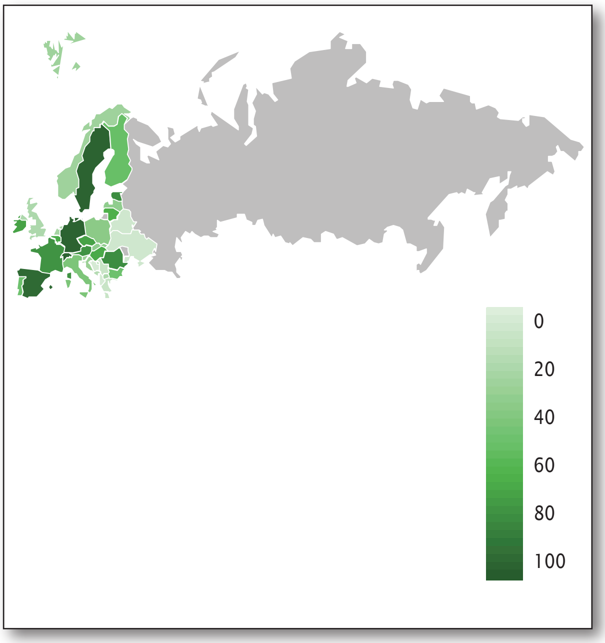


FIGURE 56

Developed SHP by country in Europe (%)

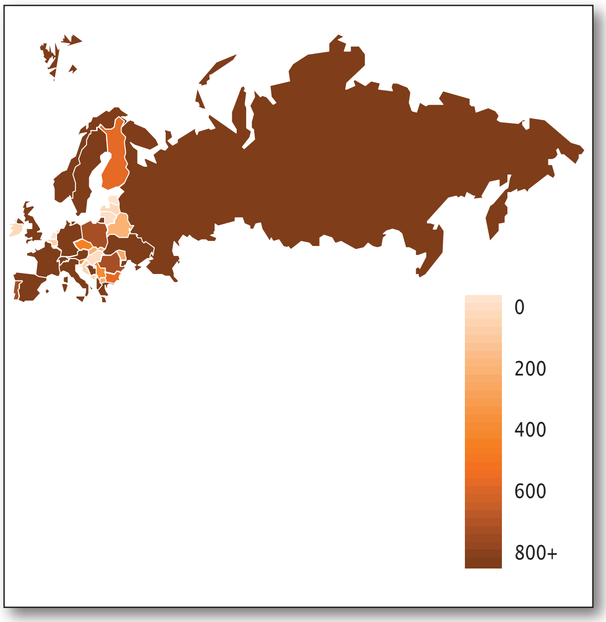


included in this Report already have FITs incorporated into their respective SHP policies.

The general challenges the region faces with regard to SHP development are the rigid environmental regulations that may hinder the development of SHP capacities in some countries. Many environmental organizations in Europe also have a negative outlook on hydropower systems in general, and thus promote policies and actions that do not differentiate between large hydropower and SHP.

FIGURE 55

Potential SHP capacity by country in Europe (MW)



The Russian Federation (Russia) provides a mechanism for 'joint projects with third countries' that incentivizes European Union (EU) Member States to support the construction of renewable energy installations, such as SHP plants, in non-EU countries. This supporting mechanism is relevant for the renewable energy projects in the north-west of Russia, from where Russia can export electric power to EU Member States.

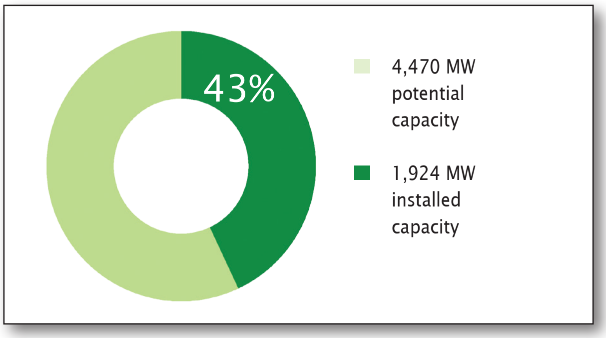
Eastern Europe

Belarus, Bulgaria, Czechia, Hungary, Republic of Moldova, Poland, Romania, Russian Federation, Slovakia and Ukraine

Eastern Europe has a considerable amount of installed SHP capacity at 1,924 MW, representing more than 43 per cent of the less than 10 MW potential of 4,470 MW. The percentage of developed SHP has decreased since the *WSHPDR 2013*, largely due to an increase in the SHP potential capacities of several countries. It should be noted that the potential does not include data for Russia; only data for less than 30 MW were available (some 825,845 MW).

FIGURE 57

Developed SHP potential in Eastern Europe (%)

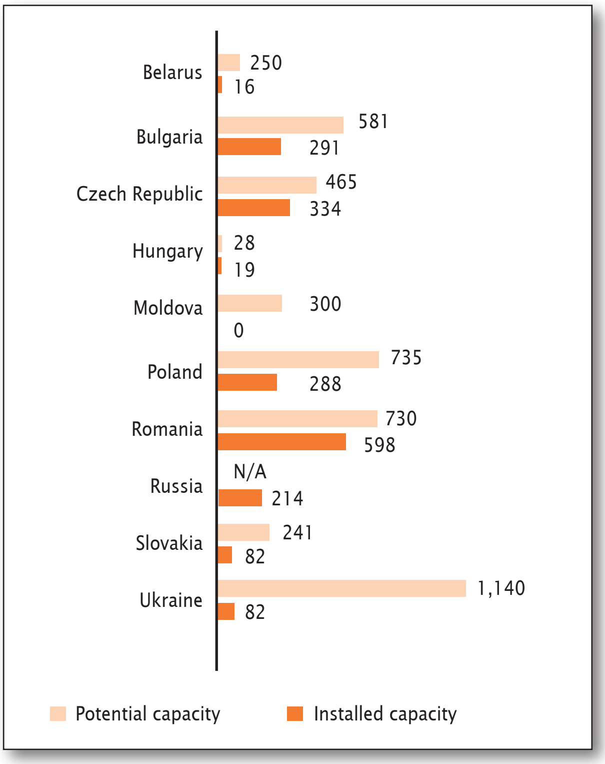


Nevertheless, there is still considerable SHP developed in some countries of the region, such as Bulgaria, Czechia and Poland. Significant potential has yet to be developed in countries such as Ukraine and Russia. Of the 10 countries, six have established FITs, namely, Bulgaria, Hungary, Poland, Romania, Czechia and Ukraine.

All the countries in the region have implemented policies aimed at promoting renewable energy sources (RES). However, as large hydropower encounters ever more barriers due to the environmental degradation that dams have caused, numerous countries have neglected the SHP sector altogether. Instead, the region has taken proactive steps to focus on the development of other renewable energy sources, primarily wind and solar power.

FIGURE 58

SHP capacities in Eastern Europe (MW)



Additionally, Eastern Europe faces many bureaucratic and financial barriers to SHP development. The lengthy administrative processes, for example, which are mostly aimed at safeguarding the environment, have unfortunately stalled the SHP sector and even lessened the significance of SHP, with environmental organizations perceiving it as a moderate source of green energy at best.

Lastly, many countries in the region also lack master development plans needed for a productive and sustainable SHP sector. As a result, investors usually have to take more risks to ensure the success of an SHP project, which often deters investors altogether.

Northern Europe

Denmark, Estonia, Finland, Iceland, Ireland, Latvia, Lithuania, Norway, Sweden and the United Kingdom of Great Britain and Northern Ireland

Northern Europe has the third-highest total SHP potential in Europe, with 10,920 MW. However, 70 per cent of this potential is found in Norway. Other countries, such as Denmark and Sweden, have fully developed their known viable SHP potential.

SHP capacity has increased by 18 per cent compared to data from *WSHPDR 2013*, from 3,643 MW to 4,292 MW. The total estimated potential has also increased by 185 per cent, from 3,831 MW to 10,920 MW. This indicates that approximately 39 per cent has so far been developed. While *WSHPDR 2013* indicated over 90 per cent of SHP developed in the region, the percentage has decreased significantly with the addition of a more accurate and higher potential for Norway.

Of the 10 countries reviewed, six have established FITs for SHP, namely, Denmark, Estonia, Ireland, Latvia, Lithuania and the United Kingdom of Great Britain and Northern Ireland (United Kingdom). The notable exceptions are Norway and Sweden, both of which operate a shared

FIGURE 59

Developed SHP potential in Northern Europe (%)

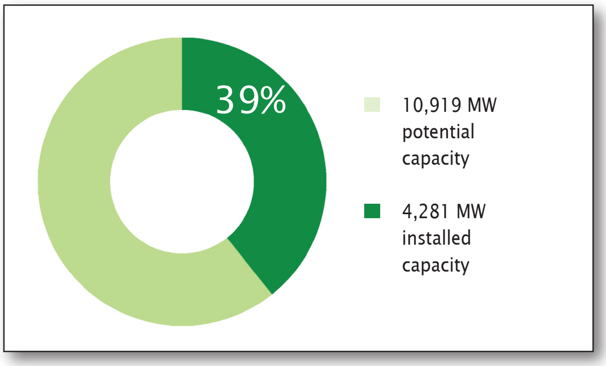
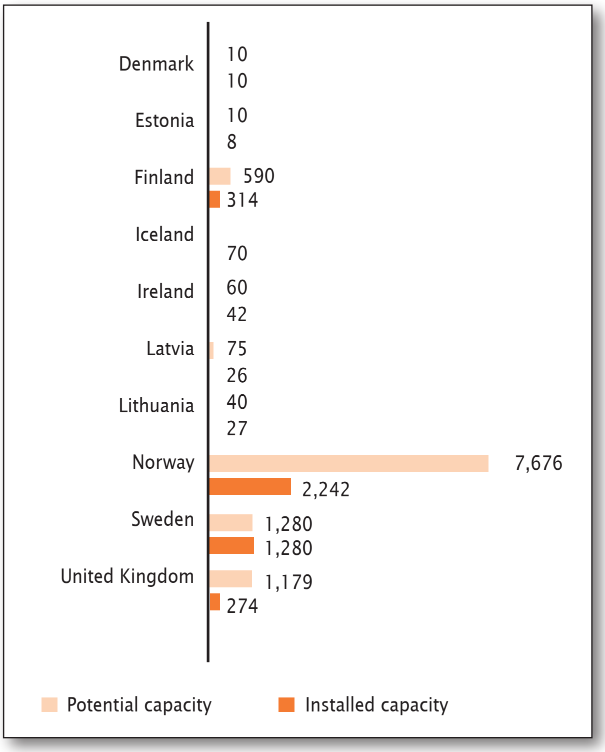


FIGURE 60

SHP capacities in Northern Europe (MW)



market with a green certificate scheme for renewable energy producers in place of guaranteed tariffs. Finland does not have FITs but has established other investment schemes that promote SHP.

Within the Northern European countries, the installed capacity and potential capacity vary dramatically—from values of over 1,000 MW in Norway and Sweden to under 10 MW in Denmark and Estonia. As a result, some countries, such as Norway, have a large interest in developing their substantial potential while others, such as Denmark, want to achieve 100 per cent power generation from renewable energy sources, but cannot do so with SHP.

The dramatic variations of SHP potential have undoubtedly been reflected in the developments of the SHP sector in the region. Norway, for example, has increased its SHP installed capacities by 26 per cent and the United Kingdom, by 19 per cent. Iceland has also increased its installed capacity by over 100 per cent, from 25 MW to 70 MW. However, the SHP potential in Iceland has not been thoroughly studied and is thus unknown. All the Northern European countries have introduced renewable energy policies supporting electricity generation from renewable energy sources, including support mechanisms for SHP. The overall goal of these renewable energy policies is to increase the share of renewable energy by 2020.

Northern Europe still faces some barriers to SHP development, mainly due to the exceptionally low electricity costs in the region, which often has led to the need of extending payback periods for SHP investments. This also results in the investment costs of SHP development to be initially higher than expected and thus can deter investors from the region. Lastly, the SHP sector has been slowed down by the environmental requirements and legislation of many countries in the region.

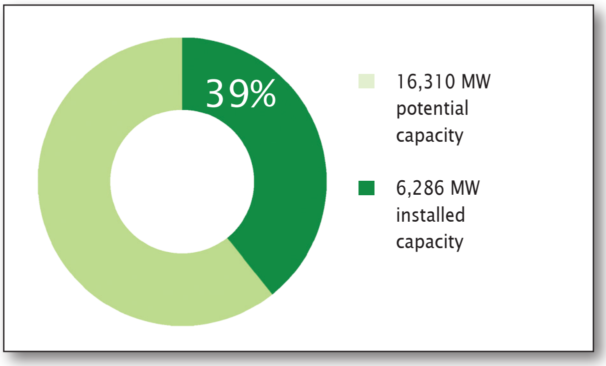
Southern Europe

Albania, Bosnia and Herzegovina, Croatia, Greece, Italy, the former Yugoslav Republic of Macedonia, Montenegro, Portugal, Serbia, Slovenia and Spain

The overall installed capacity in Southern Europe is 6,286 MW while the estimated potential is 16,310 MW. This indicates that approximately 39 per cent has so far been developed.

FIGURE 61

Developed SHP potential in Southern Europe (%)



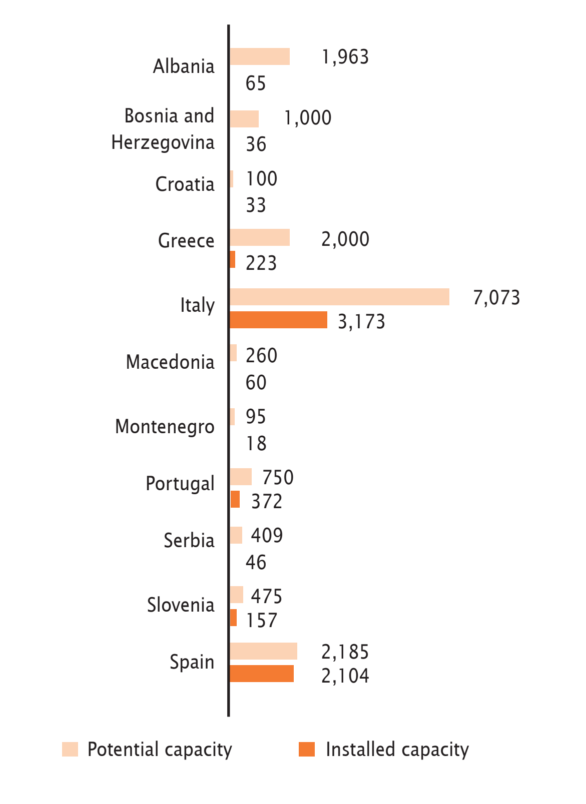
Italy is the most viable country in the region for SHP development, taking up 50 per cent of Southern Europe's total installed capacity and 43 per cent of its total potential capacity.

The region has a significant amount of untapped SHP potential—estimated to be at least 16 GW—as well as other renewable energy sources. In order to promote the development of renewable energy, all countries of the region have implemented economic incentives. These incentives have also driven the growth of SHP and further promoted policies that allow suppliers of electricity from renewable sources to receive a range of benefits. The benefits include FITs, priority connection to the grid, guaranteed purchase of electricity, preferential access to the network and other government subsidies. Of the 11 countries covered in this Report, 10 have FITs for SHP in place, the exception being Spain, which suspended FIT pre-allocation in 2012.

Southern Europe still faces a few barriers when it comes to developing the SHP sector, mainly due to the long and complicated authorization and licensing process—a complication that exists in Greece, Italy, Montenegro, Portugal, Serbia and Spain. Other institutional and

FIGURE 62

SHP capacities in Southern Europe (MW)



regulatory barriers include corruption, disagreement between local and national regulations, and even frequent changes in SHP regulations.

Western Europe

Austria, Belgium, France, Germany, Luxembourg, Netherlands and Switzerland

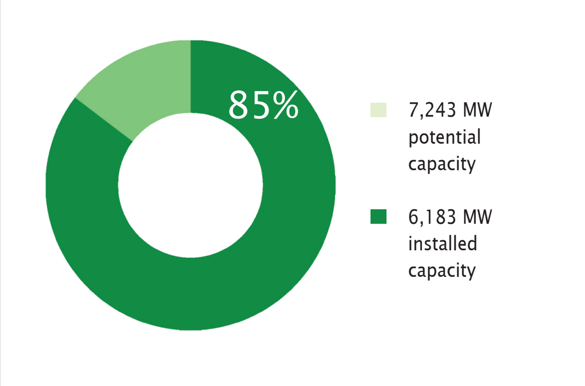
Western Europe has developed 85 per cent of its estimated potential, the highest SHP developed rate in the world. Countries such as Austria, France and Germany have developed significant shares of their relatively large SHP estimated potential. Nonetheless, additional studies are needed to ascertain the potential for applications of hydropower technology, such as in-conduit turbines, as well as the conversion or rehabilitation of existing waterways and dam structures.

The total installed capacity in the region is 6,183 MW, with an estimated potential of 7,243 MW. Aside from Belgium and Switzerland, all the countries have established FITs for SHP.

Western Europe has many SHP policies, with all countries enforcing some form of SHP mechanism. These mechanisms range from tradable green certificates, as seen in Belgium, to investment support or subsidies, as seen in the Netherlands and Austria.

FIGURE 63

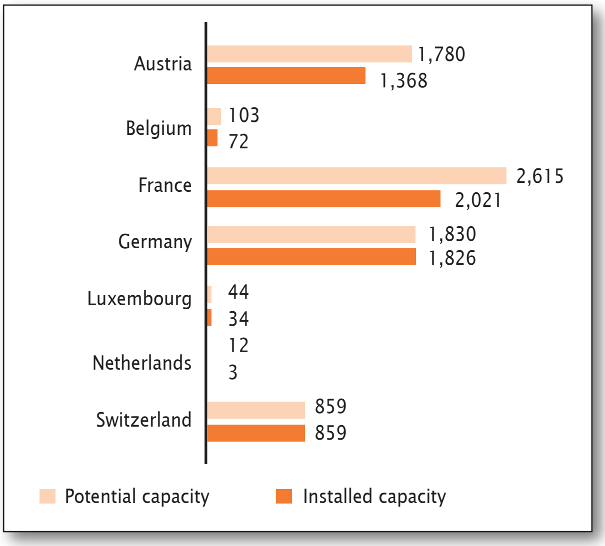
Developed SHP potential in Western Europe (%)



All the countries in the region, with the exception of Switzerland, also benefit from the Water Framework Directive, a European Union (EU) regulation on SHP and hydrology in general.

FIGURE 64

SHP capacities in Western Europe (MW)



Despite the exceptionally high SHP development rate in the region, Western Europe still endures several challenges in regards to further developing its SHP sector. The greatest obstacle involves the higher environmental expectations regarding hydro-morphology. For example, though the Water Framework Directive is a regulation aimed at establishing 'good status' on all water bodies within the EU's jurisdiction, it also imposes strict environmental conditions, which has restricted the energy production of SHP and jeopardized the economic viability of new and existing SHP projects. A modification of the EU environmental regulations is expected in 2017, which may relieve some of the strict conditions on SHP.

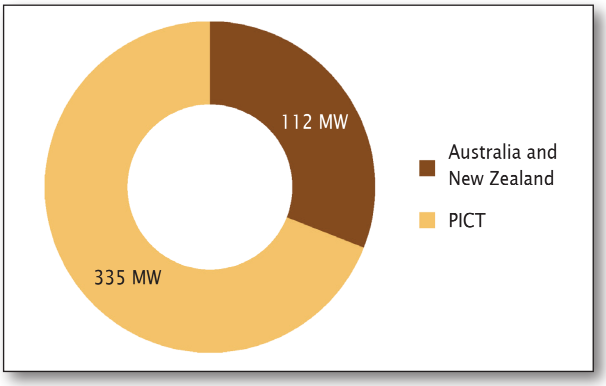
Sources: All data for this region are referenced in the respective chapters.

Oceania

Oceania is the smallest region in terms of the number of countries included in this Report as well as in installed and potential capacity. The total installed capacity amounts to 447 MW. The total estimated potential is at 1,206 MW, indicating a decrease of 2.6 per cent in comparison to *WSHPDR 2013*. This decrease is due to a reassessment of some sites in New Zealand that have been disqualified for development since 2013. The installed capacity and newly assessed potential capacity indicate that approximately 37 per cent has so far been developed. Of the 10 countries from the region, none has established FITs relating to SHP.

FIGURE 65

Installed SHP capacity in Oceania (MW)



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 a mountainous terrain, which is usually a key factor in prompting SHP potential. The Australia and New Zealand region, which is found in the southernmost part of Oceania, is the richest area in regards to SHP potential, while the Pacific Island Countries and Territories (PICT) are mostly flat islands and have little or no SHP potential. As a result, the greatest challenge for SHP development in Oceania is the topography.

FIGURE 66

Installed SHP capacity by country in Oceania (MW)

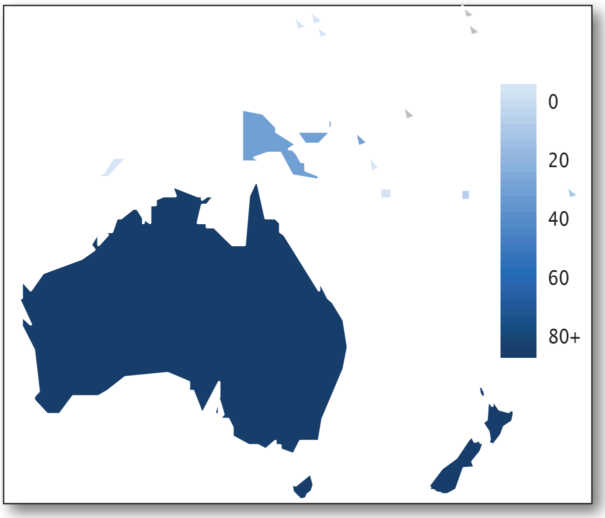


FIGURE 67

Potential SHP capacity by country in Oceania (M)

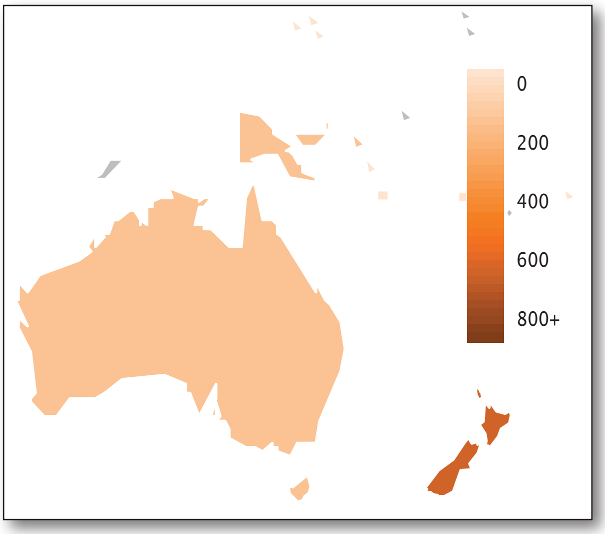
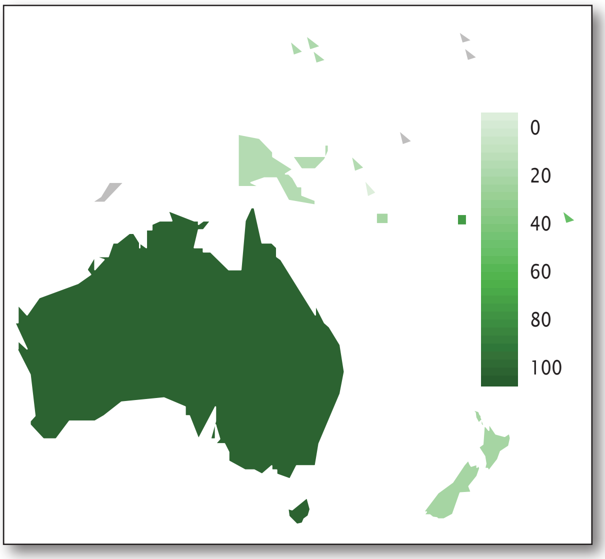


FIGURE 68

Developed SHP by country in Oceania (%)

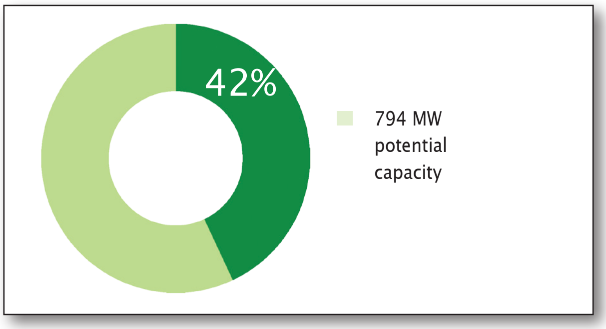


Australia and New Zealand

The region consists of just Australia and New Zealand and yet constitutes 75 per cent of the installed SHP capacity in Oceania and 66 per cent of the estimated potential. The total installed capacity is 335 MW, an increase of 8 per cent compared to data from *WSHPDR 2013*, and the potential is estimated to be at least 794 MW, a decrease of 15 per cent. It should be noted that there have been no comprehensive SHP studies in Australia and therefore the total SHP potential is not known. The Report uses the country's installed capacity as the minimum threshold for SHP potential. Moreover, the decrease of potential capacity in Australia and New Zealand is due to new data that appeared for New Zealand, which exclude sites in conservation zones and sites that are simply not economically feasible. This newly acquired data indicate that approximately 42 per cent has so far been developed.

FIGURE 69

Developed SHP potential in Australia and New Zealand (%)

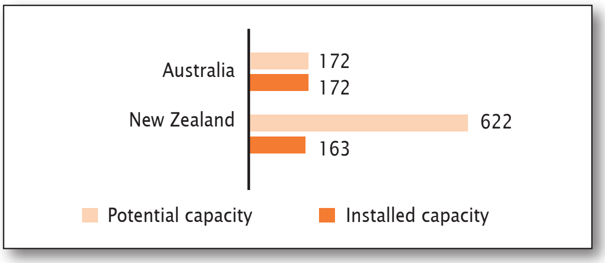


The Australia and New Zealand region did not have much development within the SHP sector, mostly due to the lack of policy in the two countries, which is generally needed to drive and implement SHP. While New Zealand has had some SHP plants installed since 2013, bringing its total capacity from 138 MW to 163 MW, Australia has had no development. It is believed that both countries will focus their efforts on other renewable energies, mostly wind and solar.

The region also faces two great challenges to developing SHP. The first is that many of the sites where SHP development is suitable are in protected areas or have significant potential environmental and social issues that require a long and expensive consenting process.

FIGURE 70

SHP capacities in Australia and New Zealand (MW)



The second challenge is that SHP development requires a lot of financial investment, with costs for new generation being higher than market prices, even with renewable energy credits. Therefore, the two countries often find difficulty in funding SHP projects.

Pacific Island Countries and Territories (PICT)

Fiji, New Caledonia, Papua New Guinea, Solomon Islands, Vanuatu, Micronesia, French Polynesia and Samoa

The Pacific Island Countries and Territories (PICT) region is an amalgamation of the Melanesia, Micronesia and Polynesia regions and consists of Fiji, New Caledonia, Papua New Guinea, Solomon Islands, Vanuatu, Micronesia, French Polynesia and Samoa. A number of smaller island nations and territories are not covered in this Report as they do not have any known SHP capacity.

The PICT region has just 112 MW of installed SHP capacity and 412 MW of estimated potential capacity, indicating that only 27 per cent has been developed. In comparison to data from *WSHPDR 2013*, the installed capacity has increased by 10 per cent while the estimated potential has increased by 35 per cent.

FIGURE 71

Developed SHP potential in the Pacific Island Countries and Territories (%)

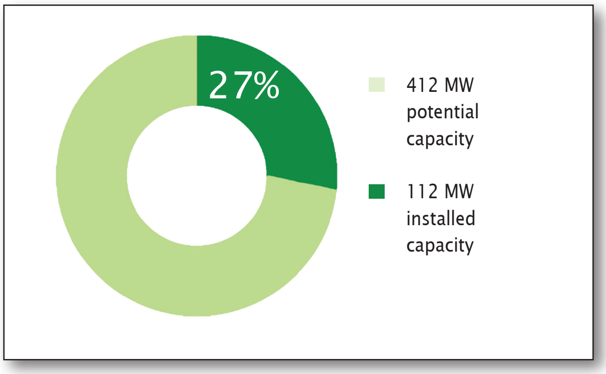
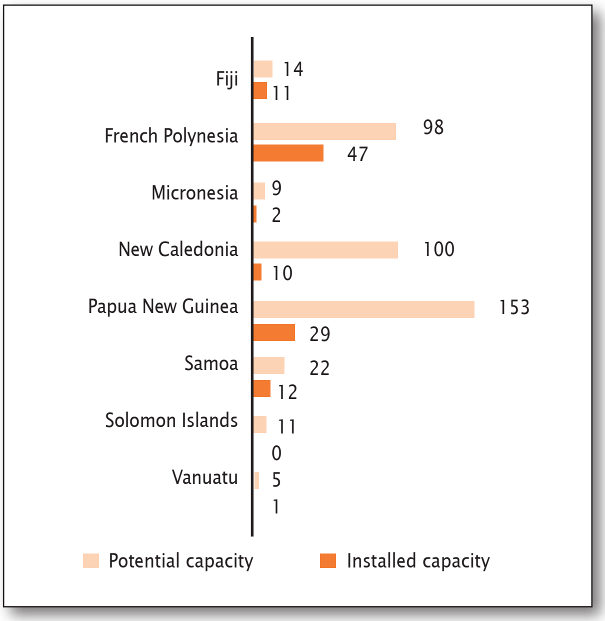


FIGURE 72

SHP capacities in the Pacific Island Countries and Territories (MW)



All of the countries, with the exception of Fiji, have proactively conducted feasibility studies in the last three years to further establish the prospective SHP sites. Furthermore, New Caledonia, in particular, is enforcing new governmental reforms that allow for the development of renewable energy projects. Specifically, the island has published new information on hydropower potential, which shows a significant increase of the potential capacity.

Sources: All data for this region are referenced in the respective chapters.

Conclusions

SHP is a mature and versatile technology, effective for increasing access to clean and sustainable electricity in the developing world, particularly in rural communities. SHP also helps developed nations achieve renewable energy advancement and targets in reducing greenhouse gas emission. Through developing SHP, many countries have already taken steps—or are beginning to take steps—to alleviate poverty and increase access to electricity, both of which are key elements in the Sustainable Development Goals and the Sustainable Energy for All (SE4ALL) programmes.

China and India are two examples that have taken advantage of the effectiveness of SHP in recent years, both having taken leading measures to improve electricity access through SHP development. Moreover, there has been a significant increase in other countries proceeding to follow their lead.

The purpose of this Report is to illustrate the development that SHP had, and continues to have, to the world. In regard to SHP potential, this Report demonstrates great improvements and impacts throughout all the major continents of the globe. This notion certainly takes an even more powerful influence when it comes to battling the greater global energy issues that plague many countries, such as dependency on fossil fuels. Nevertheless, the Report also demonstrates that there is still room for improvement. South America, for example, continues to possess large amounts of potential but—aside from Brazil—the region has so far not developed any significant portion of it.

The importance and advantages of SHP as a solution to rural electrification and inclusive sustainable industrial development also still remains underestimated. This is exposed particularly when SHP is compared to other small-scale renewable energies. For example, the Report cites that the focus many countries have on their wind and solar potential through fiscal incentives often becomes a barrier for SHP, as those same incentives are usually not extended to SHP. In some cases, such as in Algeria and Saudi Arabia, this fiscal focus is due to a simple lack of appropriate SHP resources. In other cases, the focus is due to a lack of studies to determine accurate potential figures, which then often leads authorities to pursue more readily achievable projects in the wind and solar sectors. Additionally, while the power obtained from SHP plants is significant, the initial costs of project implementation can be considerable in comparison to other technologies. This, too, discourages both government officials and private investors from taking interest in SHP. Lastly, SHP sometimes suffers from poor public perception concerning the environmental and social impacts normally associated with large-scale hydropower projects.

Despite the underestimation of SHP, the publishing of this Report does record new progress and challenges since *WSHPDR 2013*. For example, due to newly available data, the potential of SHP in the Russian Federation (Russia) has been demonstrated to be much larger than previously reported (up to 30 MW). This indicates the status of SHP development in Russia has vast opportunities for growth, with only 0.10 per cent of its capacities developed. The change is drastic and demonstrates both an achievement and a challenge. The achievement is that the re-evaluation of the true SHP potential in Russia—thus in Eastern Europe and, more largely, in all of continental Europe—provides a more accurate portrait of the SHP landscape and future development opportunities. The challenge, however, is that Russia now needs to re-evaluate its legislation in order to create incentives for tapping into such a rich energy potential.

This section provides general conclusions from *WSHPDR 2016*. Despite an increase in SHP development, many of the conclusions and recommendations remain similar as in the previous report.

The need for data

One conclusion that remains unchanged from *WSHPDR 2013* is the need for accurate and shared data on SHP potential at a country level. A commonly cited barrier to SHP development in developing countries is the lack of accurate data to encourage private investment in the sector. For many of the countries reviewed in this Report, the available data are outdated, dependent on studies or reviews that are often decades old and not the true representation of current technological improvements or policy frameworks that greatly impact the accuracy or feasibility of technical and economic estimates. Detailed information on SHP potential informs potential investors about suitable areas and reduces the costs for feasibility studies. To truly realize the full potential of SHP around the globe, and to attract private investment to the sector, governments need to seriously consider the importance of new and detailed studies that incorporate the latest technological and economic developments. Additionally, international donor programmes and other development funds should consider the value of financing similar studies at the local level.

In developed countries a common barrier is that the majority of known SHP resources have already been developed. Nonetheless, many of the assessments are based on outdated studies and new comprehensive reviews utilizing computer models based on geographic information system (GIS) are likely to reveal additional potential. Many of the existing assessments do not include the potential for either the rehabilitation of old sites or the development of existing waterways and dams for SHP use. For example, across the world, there are many water reservoirs and dams constructed for irrigation or drinking water collection that do not yet produce electricity, so SHP turbines could be installed and run concurrently with the larger system.

Europe already has a considerable amount of its SHP developed. Nevertheless, a study by the European Renewable Energy Sources Transforming Our Region (RESTOR) hydro project between 2012 and 2015 has identified some 50,000 historical sites, mills and hydropower stations that are currently inoperative but suitable for SHP redevelopment. In Latvia, for example, these sites are considered as some of the only undeveloped potential for SHP remaining in the country. However, sites such as these are often not included in assessments of national potential. Furthermore, regulatory barriers have prevented development of SHP in some cases. In Poland, for example, ownership of many of the identified sites remains unclear and a new government policy is required to establish access for independent power producers (IPPs) to develop them.

Most countries also lack assessments of how new and non-conventional SHP technology could significantly increase potential. In-conduit turbines that can be incorporated into waste or drinking water systems—such as those that have been successfully implemented in the USA—promise to significantly increase the total potential in developed countries. Additionally, new low or zero head turbine designs can provide SHP in previously unconsidered locations that are often closer to population centres. This lowers the overall cost and can be of great benefit to rural electrification programmes.

Lack of focus on small hydropower

Focus on other forms of renewable energy such as wind and solar power has, in some cases, hindered progress within the SHP sector. In countries such as Egypt and the Dominican Republic, policies and financial incentives aimed at other forms of renewable resources do not apply to SHP. In other cases, focus is overwhelmingly in favour of large hydropower. Paraguay, which has an extraordinary hydropower potential and relies heavily on large hydropower, has yet to develop SHP at all. SHP potential is also often associated with large hydropower potential and consequently given less attention when the latter has achieved high levels of development. A lack of governmental stimulus for SHP owes itself in part to the perceived lower financial gains as well as a lack of data on total SHP potential. While the development of renewable energy resources should not be discouraged, governments would benefit from new studies on total SHP potential as well as from introducing new legislation that fully understands the contribution that SHP can make in providing clean sustainable energy.

Financing small hydropower

Attracting finance for SHP is key to the sector's development. Approaches adopted by developers vary around the world, including community finance, public funding, equity investment, and grants and loans from local financing institutions. In developing countries, most notably in Africa, most of the existing SHP development has so far been realized through grants or soft loans from foreign development institutions or other countries. The key concern with this approach is the unsustainability of the model. Efforts have increased to create environments that are financially attractive for private investment.

However, creating an attractive environment for investment is often hampered by a number of competing issues that need to be addressed before suitable incentives can be established. This includes, most notably, investment in a robust electricity sector with a suitable grid coverage and infrastructure.

Although the medium- and long-term benefits outweigh the high levels of initial investment, SHP is still often perceived as high risk by investors. This can be further exacerbated by uncertain and unclear legislation and guarantees for producers. Clear and uncomplicated legislation and regulatory processes alongside adequately designed financial incentives are thus required.

Appropriate policies and regulations

The lack of clear policies as well as regulatory and institutional frameworks regarding renewable energy and SHP are important barriers to development. While many countries have renewable energy targets, including targets specifically for SHP, they nonetheless require appropriate and well-defined pathways to achieve these targets.

There are a number of policies that have the potential to improve development opportunities, including: obligations to conclude long-term power purchase agreements (PPAs) with renewable energy producers, FITs, net-metering policies for small-scale projects and priority access for renewable energy.

In addition, the goals of renewable energy development plans need to be aligned with those from other sectors such as water and environment. In Montenegro, for example, an attractive environment for investment is hindered by a conflict between various national documents and regulations.

Feed-in tariffs

FITs are a common tool used to provide a credible guarantee for the purchase of electricity from renewable energy sources, thus increasing the confidence of banking institutions and facilitating longer-term loans at more affordable interest rates. The Renewable Energy Policy Network for the 21st Century (REN21) notes that FITs account for a greater share of renewable energy development than either tax incentives or renewable portfolio standard (RPS) policies. As of 2012, it was estimated to be responsible for 64 per cent and 87 per cent of the world's wind and photovoltaic installed capacities. Although analysis of the precise impact of

FITs on SHP development was not among the aims of this Report, a general pattern can be observed with many of the countries without FITs witnessing comparatively low levels of SHP development. Although FITs are not the only method for encouraging development, as the European Commission has concluded, "well-adapted Feed-in tariff regimes are generally the most efficient and effective support schemes for promoting renewable electricity". Thus, in agreement with the European Commission, this Report advises that countries with low levels of SHP development should seriously consider the option of introducing these incentives or similar financial guarantees.

Nonetheless, FIT policies need to be tailored to the specific needs of the country and poorly structured FITs can have a more negative-than-positive effect on SHP development. Tariffs in Ghana, for example, have been criticized for being inadequate. A few of the critiques in Ghana are as follows: having too short of a guarantee period (10 years); having no green power priority rule; and vague conditions in regards to who bears the cost of grid connection and grid enhancement. FITs are not strictly based on the cost of generation, given the currently low levels of consumer tariffs, it is also unclear how the programme will be financed, potentially deterring more risk-adverse investors. In general, FIT schemes in Africa are working poorly due to unfavourable institutional design, insufficient design, and insufficient level of FIT rates or obstacles in the process of implementation.

Deficiencies, however, can be explained by conflicting policy targets, most notably the need for affordable power prices. FITs are expensive and thus it is paramount that energy policies be clear on how the costs are absorbed. For example, until 2012, there were two different financial support options in Spain—an 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 (RES-E) due to a tariff deficit of roughly EUR 26 billion (US$28.7 billion). The deficit was largely driven by the incentives to renewable energy sources.

In many developed countries where FITs have been adopted, the cost is, at least in part, passed on to the customer. In developing countries, however, the cost for electricity is already too high. In these cases, FITs may not be an economically viable or politically attractive option for policymakers. Therefore, developing countries instead have opted to establish PPAs between producer and supplier. However, this too poses many challenges, as it often leads to protracted discussions, higher costs and risks that deter banks from issuing loans. South Africa is an example of a FIT scheme that became ineffective due to the negotiations between producers and the grid.

In addition, many developing countries lack suitable grid-capacity to implement FITs without limitation. Thus for the developing countries in this Report that have established FITs or are planning to, caps are often used to limit the total share of renewable sources as well as minimum sizes to avoid smaller plants that may have higher generation costs per kWh. By limiting the share of FITs, caps can also limit the impact on prices for the customer.

In general, the establishment of FITs must be part of—and aligned to—a wider development strategy. Governments might also consider how international donors and climate finance instruments can contribute to the overall costs.

While FITs have become somewhat of an international norm, it should be noted that several countries are actively seeking alternatives to replace existing tariff policies. For example, Brazil and Peru have employed energy auction models and seem to prefer it to FITs. However, though auctions can be an efficient avenue for fostering private investment, the model does tend to favour the sale of low-cost energy, leaving SHP at a disadvantaged position in comparison to other renewable sources. Nevertheless, there are ways to avoid these disadvantages, mainly with reformulations in the energy auction rules. If countries that employ the auction model commit to reforms, auctions can actually prove to be a more efficient model for SHP development. This is especially the case for developing countries with already high electricity costs. Brazil is an example of one successfully making these reforms. In 2015 the country established larger cap costs, making energy sources such as wind and SHP more equally competitive. As a result, SHP plants in Brazil are seen to be recovering in the regulated market and will continue to do so as time passes.

Renewable Energy Portfolios (REPs)

While FITs can be the most prominent economic instrument to promote renewable energy technology if the right circumstances are present, other tools may be appropriate. Renewable energy portfolios (REPs) are a useful and common policy tool for the promotion of renewable energy in general. REPs require electricity suppliers to source a specific share of the electricity they purchase from renewable energy sources. As such, they differ from FITs by allowing for more price competition between different renewable energy sources. REPs are usually established alongside certification programmes that oblige suppliers to purchase renewable energy certificates from generators. This can provide a useful financial incentive to IPPs. However, since certification programmes are operated on a market basis, it can lead to situations where certificates become significantly devalued as a result of oversaturation of the renewable energy marketplace. This ultimately can deter future development and investment. Such has been the case in countries such as Norway, Sweden and Poland, with the value of Polish certificates falling to just 40 per cent of their long-term stable price. As a result, commercial entities strengthened their requirements, increased loan rates for new offerings, asked for additional loan collateral, stopped renewable energy financing and examined financing applications of all projects. This also increases the risk of a reduction of existing plants due to decreased income for renewable energy producers.

Considering the different financial incentives for SHP development and their relative benefits and risks, it is important to establish not only a more robust analysis of the effectiveness of these policies but also a platform for policymakers in different countries to share experiences. This will help identify the most suitable financial mechanisms for developing SHP in different socio-economic and political environments. Knowledge exchanges involving ministries, utilities, regulators, financiers, project developers and community representatives have been a successful tool in this context.

Technology and skills

A lack of appropriate technical skills and indigenous technology is seen as a significant barrier in many countries that has hindered both planned and existing SHP projects. In countries with insufficient indigenous technology, access to foreign imports can be aided through the establishment of concessionary duties and reduced import taxes.

Capacity building is one of the key measures for advancing the skills needed for the maintenance of SHP. With week-long trainings, experts can teach the local population how to manage an SHP system and even repair it should there be technical problems in the future. Kenya was recently a recipient of a successful SHP capacity-building training session provided by ICSHP and COMESA. The two organizations coordinated a five-day training in Nairobi to spread and share advanced Chinese SHP technology and experience within the COMESA countries. The coordinators visited the Wanjii Hydropower Station of the KEN-GEN in Muranga County and set it as an example of successful international cooperation for green energy in a developing country.

Despite the successes that several international organizations have had in promoting SHP, more cooperation is needed from experienced countries, especially in regards to providing technical assistance in the planning, development and implementation of SHP projects. In particular, the need for suitable experts to assist in feasibility studies is needed.

Infrastructure and grid access

A common issue for all countries is that, given the nature of SHP technology, appropriate sites are often located in remote areas without access to the local grid. Unless there is explicit government support in the form of policies that guarantee the cost of connection, the costs for some sites can be prohibitive. This is especially true for developing countries with limited grid capacity and coverage. Establishing robust and extensive grid networks that can accommodate the introduction of new small-scale renewable energy developments is a priority when seeking to attract private investment capital. Establishing micro-grids with SHP providing base-load power offers a short- to medium-term—or even permanent—solution for electrifying remote and inaccessible communities. Additionally, for many developing countries, distribution losses are high, requiring investments to match those in generation and transmission.

Environmental regulations

Environmental regulations have led to complications in developing the SHP potential in some countries as well as increased costs of installations. SHP technology has advanced to lower the impact on the environment and provide suitable protection for surrounding eco-systems, most notably migratory fish. For several, mainly developed countries, new environmental protection regulations have placed strain on potential SHP sites because either the regulations require additional costs that make projects unfeasible or they prevent development entirely. In Norway and Sweden, for example, feasible SHP potential has been almost completely developed due to the implementation of a new regulation that has rendered development of potential sites illegal or economically unviable. Similarly, in Austria, there have been requests from the government regarding environmental concerns. One example involves fish conservation, specifically fish bypassing an SHP system and reserved flow. In this case, the government consensus took a while to reach and many have criticized the consensus itself as being unstable and unreliable for both fish conservation and SHP development.

Although ensuring a low environmental impact should be fundamental to SHP development, governments should consider SHP developers as important stakeholders when devising and implementing regulations. At the same time the industry must continue to lower the impact of SHP and seek lower-cost technology in order to ensure that environmentally sound sites remain viable.

Bureaucratic barriers

A number of countries highlight cumbersome and lengthy administrative processes as one of the biggest barriers to development. Complicated permit requirements that cross numerous departments are costly, delay project implementation and discourage investors. For example, in the Netherlands, the main limitation for SHP results from the low hydrological potential in a flat country, but the biggest restriction is receiving a permit from the local water communities ('*Waterschappen*'). The permit can simply be for the purpose of determining whether there is potential of an SHP site, and not construction. But even this is extremely difficult. The country does have quite a few places where development of an SHP plant could be possible, and yet the development of SHP is nearly halted due to the lobby of recreational and professional fishermen.

Faster development can be encouraged by streamlining the licensing process with several experts suggesting the implementation of a one-stop shop—a single responsible agency with standardized contracts. In addition, legislation covering land acquisition of suitable sites for development needs to be clear and transparent. This would both lower costs and speed up development.

Knowledge sharing

Knowledge sharing between experienced countries and those with undeveloped SHP resources is crucial. While ICSHP and UNIDO operate such programmes, these need to be expanded and improved through additional funding.

In Nigeria, a collaborative workshop between the Energy Commission, UNIDO and other stakeholders, devoted specifically to SHP for rural development, has helped to formulate future strategies for the sector's development. This resulted in a memorandum of understanding signed between the Commission, UNIDO and ICSHP for further cooperation in harnessing the identified SHP potential.

As can be noted with Nigeria and ICSHP, networking, practices of knowledge sharing and information dissemination through forums and conferences are a basic requirement for SHP development.

Public perception

While SHP does not incur the same environmental costs as large hydropower projects, it nonetheless tends to suffer from a similarly poor public image. The development of the sector, as well as the implementation of policies designed to encourage that development, i.e. FITs, needs the backing of all its stakeholders in order to be successful. SHP should be promoted as a source of clean energy, an excellent replacement for wood-fuel for lighting, and ideal for electrification in suitable remote locations.

The impact of climate change

Climate change threatens the reliability of SHP, with experts from several countries citing erratic and unpredictable weather as a key barrier to development. One of the main advantages of SHP is the predictability of supply as opposed to other sources of renewable energy, such as solar or wind. Erratic water supplies can also lead to competition between small hydroplants and other sectors, most notably drinking water, leading to plants running less efficiently. Future assessments of SHP sites may need to start including assessments of how changing weather patterns may impact site efficiency and plan accordingly. In addition, better water management systems can help alleviate conflict between the different users of water resources. However, far from reducing the need for SHP, the impacts of climate change only highlight the desperate need for countries to adopt this and other forms of renewable energy as quickly as possible.

Recommendations

The following recommendations are aimed at the national, regional and international levels. They are provided as general recommendations and should not be considered as comprehensive.

National level

Resource assessment

1. Developing countries should undertake a detailed analysis of potential SHP resources in order to lower the cost for development and encourage private investment. Development funds, grant-making institutions and international NGOs should consider the possibility of supporting the costs of these studies.

2. Developed countries should similarly undertake detailed assessments of SHP potential while specifically considering new technological improvements, the conversion of existing waterways or conduits for generation, and the rehabilitation of old sites, which in some cases are applicable in developing countries as well.

3. In general, more hydrological data need to be collected over a longer period of time. In order to achieve this goal, technical equipment such as a network of prospective stations is required.

4. Existing feasibility studies of potential sites need to be reassessed due to the constant effect that hydrological and environmental changes have had on watersheds. Without this reassessment, many SHP developers are left with outdated studies that may not reflect the present conditions of selected SHP sites. New economic conditions, regulatory environments and technological improvements should also be considered.

5. Potential multi-purpose sites need to be identified to incorporate SHP into existing reservoirs and dams that were initially constructed as an irrigation system or for drinking water. These sites are often overlooked but can aid greatly in providing access to electricity and clean energy, both key elements of the SDGs.

6. Potential non-conventional sites based on technical innovation should be identified in order to determine whether existing infrastructure such as water channels with very low heads could serve as SHP sites.

Policies and regulations

7. Suitably designed policies and financial incentives already established for other sources of renewable energy should be extended to cover SHP, with a particular emphasis on green technology and energy generation.

8. Countries should assess the impact of implementing different policy tools and financial incentives to encourage SHP development. These assessments should also give due consideration to the overall design of the policy and how costs are to be absorbed.

9. Special consideration should be given to FITs and governments should consider how international donors and climate finance instruments can contribute to the overall costs.

10. Governments should develop clear laws and regulations surrounding the rehabilitation of sites, most specifically laws on land ownership.

11. Government agencies should also streamline the development process by creating a one-stop shop for standardized permits and contracts.

12. Clear targets for SHP development should be implemented as a part of a broader target for renewable energy. This should include appropriate and well-defined pathways that will guarantee the achievement of these targets, which will assist countries to make their commitments for renewable energy targets. SHP can significantly increase the share of green energy generation.

13. In domestic policy, adhering to a unified, international definition of SHP would aid in policy harmonization and remove ambiguity in bilateral or transnational interactions in the SHP development process.

14. Renewable energy and SHP goals need to be aligned with competing goals from other sectors, most notably the water and environmental sectors.

15. There needs to be an improvement in collaboration among agencies responsible for water resources, environment and electricity. With this collaboration, there should also be a focus to avoid overlapped mandates and conflicting legislation while reducing the duration needed for approval/authorization processes.

16. Governments should also implement regulations on the use of waterways to avoid conflict between agriculture, fishery, electricity generators and biodiversity.

17. Developing suitable water management systems will also aid in reducing resource conflict between the competing needs of the population.

18. Government agencies should also focus on introducing new environmental regulations that give consideration to SHP developers as significant stakeholders.

19. An improvement on timely land allocation by ensuring land records are clear and up-to-date will also aid in avoiding conflict over land rights/ownership and concessions/permits.

Financing

20. Investors often face financial risk when developing SHP projects. Therefore, there should be an overall strategy that reduces the investor's risk by developing new financial policies and streamlining existing regulation.

21. High initial costs also need to be overcome with easier/improved access in order 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 in order to improve the risk assessment and provide conducive loan conditions.

Equipment and technology

22. Local manufacturing capacity is often lacking in many countries. Therefore, building or improving industries that serve as components to SHP, such as the concrete supply industry and metal manufacturers, will aid in the overall production of SHP plants.

23. National import taxes can also hinder SHP equipment provision. A solution to this can be a simple introduction of lower tax rates for the import of SHP equipment. This will also overcome the deficit of SHP technology should the country not yet have an existing SHP sector.

Infrastructure

24. SHP developers often face obstacles when they deal with the national grid. Therefore, developing robust grids with suitable capacity and coverage to accommodate additional connections will make connecting SHP plants much easier in the future. Similarly, there should be regulations that lower the cost of connecting to the grid for developers.

25. In order to avoid high distribution losses and raise overall efficiency of SHP projects, there should be an investment match in distribution systems to those in generation.

26. In some cases where isolated off-grid systems are not preferred, SHP plants in remote areas are often not economically feasible because mini-grids or connections to the central grid need to be built. By improving the electricity network planning, the need for investment into grid infrastructure will also be identified. This will help to better inform the economic feasibility of potential sites.

Skills and expertise

27. Local populations often lack the technical expertise for SHP projects. By increasing local capacities in conducting feasibility studies, construction, and operation and maintenance of SHP plants, the whole SHP sector can become more self-sufficient and long-lasting for countries.

Rural electrification

28. SHP is a great solution to increasing rural electrification, which brings access to clean and reliable energy to those populations and helps to reduce poverty, both of which are fundamental goals of the SDGs. However, there needs to be an improvement on the reporting of the impact of SHP on rural electrification by keeping track of on-grid and off-grid installed and potential SHP capacity.

29. The productive use of electricity from SHP plants in rural settings should also be better developed and thoroughly reported in order to share lessons learnt and improve inclusive sustainable industrial development.

30. A development and promotion of new business models for sustainable SHP development for rural electrification should also be mainstreamed both nationally and internationally.

International and regional level

1. Promoting SHP from international and regional institutions will be essential in mainstreaming SHP as a positive renewable energy. Therefore, international and regional agencies should focus on providing a detailed analysis on the effectiveness of FITs and other financial incentives on SHP development.

2. Global actors in the development of SHP should identify and promote the adoption of a universal definition of SHP, acceptable by international organizations and national stakeholders alike.

3. International and regional agencies should also provide reports of the impact climate change has had on SHP efficiency throughout all the regions.

4. A development of regional networks and learning exchange programmes for policymakers will help identify the most suitable financial mechanisms. These mechanisms will be suitable for developing SHP in different socio-economic and political environments. This network can include a list of professional and mechanical workshops that will help satisfy local and regional equipment demand.

5. International and regional agencies should also raise general awareness of the benefits of SHP to reduce negative impressions that impact public and investor perceptions.

6. International and regional agencies should promote new SHP designs that take into account new environmental regulations that can render potential sites unviable.

7. International development funds, grant-making institutions and NGOs should consider how supporting the implementation of financial incentives or national and regional resource assessments can serve rural electrification and/or renewable energy development efforts.

8. Promotion of sustainable models for community financing and ownership of SHP projects can also take place at the regional and international levels.

9. A regional and international network of focal points (e.g. Ministry of Water Resources and/or Ministry of Energy) should be developed in order to connect relevant stakeholders within the region.

10. International and regional agencies can also alleviate the lack of SHP expertise by using existing international technical training resources to train experts in each region.

11. By developing South-South cooperation and triangular cooperation among developing countries, developed countries and international organizations, international and regional agencies will be able to facilitate the transition of individual pilot SHP projects towards the successful implementation of full-scale SHP programmes. The cooperation should also allow for technology transfer, capacity building and financing, with International Financial Institutions (IFIs) assisting to kick-start programmes and helping to overcome funding barriers for countries in need.

12. Lastly, coordination, collaboration and knowledge sharing among regional and international organizations that include small-scale hydropower in their scope of work should continue and be expanded.

CHAPTER 1
Africa

Site visit to a small hydropower plant in Indonesia. Photo by Rana Pratap Singh

1.1 Eastern Africa

Mohamedain E. Seif Elnasr, Common Market for Eastern and Southern Africa

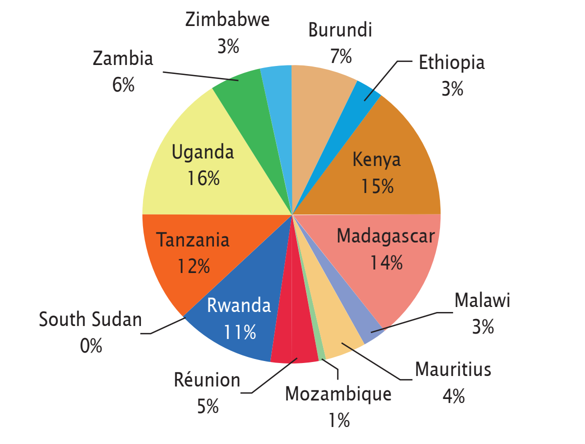
Introduction to the region

The Eastern Africa region, in the context of this report, comprises 20 countries and territories. This report, therefore, focuses on 13 countries from the region which have small hydropower (SHP) installed capacities. They are namely Burundi, Ethiopia, Kenya, Madagascar, Malawi, Mauritius, Mozambique, Rwanda, South Sudan, Uganda, United Republic of Tanzania, Zambia and Zimbabwe, as well as Réunion, an overseas department of France. An overview of the countries in Eastern Africa is presented in Table 1.

The climate and topography of the region vary widely, from humid tropical to sub-tropical savannah and plateaus to arid desert. The Great Rift Valley traverses the region and it is home to the two highest mountains in Africa, Kilimanjaro and Mount Kenya. Burundi, Kenya, Tanzania and Uganda (as well as Democratic Republic of the Congo) form the African Great Lakes region and are home to some of the largest and deepest freshwater lakes in the world. All the lakes combined in this area roughly hold one quarter of the planet's freshwater. The lakes drain into the region's major river systems, including the White Nile, the Congo River, and the Shire and Zambezi Rivers.

FIGURE 1

Share of regional installed capacity of SHP by country*



Source: *WSHPDR 2016*[5]
Note: The use of the term 'country' does not imply an opinion on the legal status of any country or territory.

Some areas within the region are mountainous and have high rainfall, in some cases upwards of 2,000 mm annually, leading to significant hydropower potential. Ethiopia, Tanzania and Zambia have the largest SHP potential as reported to date.

TABLE 1

Overview of countries* in Eastern Africa (+/– % change since 2013)

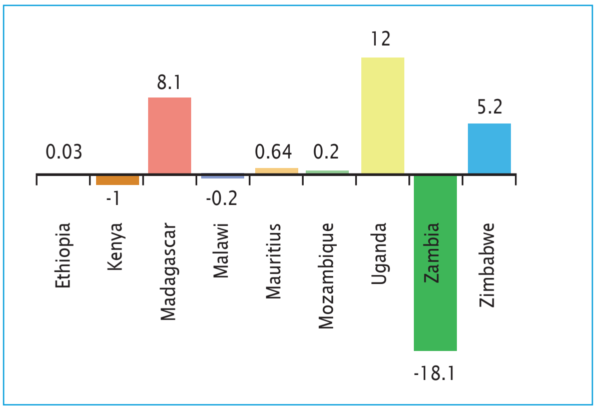
Country*	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Burundi	10.8 (+2%)	87 (-2pp)	5 (+2.3pp)	55 (+5.7%)[a]	N/A	50.1 (0%)[a]	247.5 (+59%)[a]
Ethiopia	99.8 (+9%)	80 (-3pp)	23 (+6pp)	2,255 (-)	8,719 (+112%)	2,120 (+14%)	8,265 (195%)
Kenya	45.9 (+6%)	74 (-4pp)	20 (3.9pp)	2,177 (+47%)	9,138 (+36%)	821 (+7.8%)	3,573 (+64%)
Madagascar	25.6 (+16%)	65 (-5pp)	14 (-)	564 (29%)	1,487 (+30%)	162 (+23%)	884 (+17%)
Malawi	17.2 (+5.4%)	78 (-2pp)	10 (+1pp)	435 (+38%)	1,906 (+13%)	352 (+17%)	1,868 (+69%)
Mauritius	1.2 (-)	60 (+2pp)	99 (0pp)	764 (+14%)	2,937 (+22%)	59 (0%)	90 (-10%)
Mozambique	27.2 (+15%)	68 (+6pp)	13 (+1.3pp)	2,475 (+7.2%)	14,895 (-0.5%)	2,275 (+4.4%)	14,546 (-1%)
Réunion	0.8 (0%)	N/A	99 (-)	825.7 (+27%)	2,857 (+12%)	133.6 (+10.8%)	425.8 (-32%)
Rwanda	12.7 (+8.5%)	73 (-8pp)	18 (+12pp)	140 (+102%)	481 (-)	79 (+44.9%)	432 (-)
South Sudan	12.0 (+12%)	80 (-)	1 (-)	27.4 (-)	N/A	0 (-)	0 (-)
Tanzania	49.6 (+5.7%)	69 (-5pp)	24 (+10pp)	1,597 (+51%)	6,085 (+42%)	562 (+0.7%)	N/A
Uganda	34.9 (+3.8%)	84 (-3pp)	15 (+9pp)	881 (+67%)	3,196 (+128%)	695 (+69%)	2,974 (+230%)
Zambia	15.7 (+14%)	59 (-5pp)	25 (+ 6.2pp)	2,396 (+36%)	14,453 (+51%)	2,255 (+48%)	13,745 (+39%)
Zimbabwe	13.1 (+3.8%)	67 (+5pp)	40 (0pp)	2,045 (+2%)	9,483 (+22%)	750 (+7%)	4,982 (-9%)
Total	**367 (+8.5%)**	—	—	**16,653.1 (+36%)**	**75,637 (+33%)**	**10,314 (+19%)**	**43,767 (+5%)**

Sources: Various[1,2,3,4,5,6,7,8,10]
Notes:
a. The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.
b. (*) The use of the term 'country' does not imply an opinion on the legal status of any country or territory. (a) Includes regionally shared power plants with guaranteed capacity and generation.

All countries listed in this report, with the exception of Mozambique, Réunion, South Sudan and Tanzania, are member states of the Common Market for Eastern and Southern Africa (COMESA). COMESA is a free-trade and customs union area and comprises 19 countries. It is one of the building blocks of the African Union. Additionally, six countries in the Great Lakes region (Burundi, Kenya, Rwanda, South Sudan, Tanzania and Uganda) are members of the East African Community (EAC), which is an intergovernmental organization and also one of the building blocks of the African Union.

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for Eastern Africa region



Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
Notes:
a. The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.
b. Countries and territories with no net change were not included. Zambia's decrease is due to extensions of SHP plants which are no longer under 10 MW.

With regards to the power sector, there is one existing power pool: the Eastern African Power Pool (EAPP). It has the mandate to develop energy resources in the region as well as ease access to electricity power supply to all countries in the Eastern Africa region through the regional power interconnections.[9] Countries in the context of this report which are members of EAPP include Burundi, Ethiopia, Kenya, Rwanda, Tanzania and Uganda.

Kenya, Madagascar and Uganda together account for just under 50 per cent of the regional share of installed SHP (Figure 1). Since the publication of the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, the installed SHP capacity has increased by 3 per cent from 208.6 MW to 215.4 MW (Figure 2).

Small hydropower definition

The definition of SHP varies throughout the region. However many countries accept the COMESA classification of up to 10 MW. Mozambique has the highest upper limit for SHP at 25 MW, while the lowest is in Burundi at 1 MW. An overview of the countries' definitions of SHP is available in Table 2.

TABLE 2

Classification of SHP in Eastern Africa

Country	Small (MW)	Mini (MW)	Micro (kW)	Pico (kW)
Burundi	< 1	—	—	—
Ethiopia	0.5-10	—	100-500	1-100
Kenya	1-10	—	0.1-1	< 100
Madagascar	—	—	—	—
Malawi	< 5	—	—	—
Mauritius	—	—	—	—
Mozambique	< 25	—	—	—
Réunion	< 10	0.5-2	< 500	—
Rwanda	< 5	—	—	—
South Sudan	—	—	—	—
Tanzania	< 10	—	—	—
Uganda	< 20	—	—	—
Zambia	0.5-10	—	< 500	—
Zimbabwe	1-10	—	—	—

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5].

Regional SHP overview and renewable energy policy

While many of the countries are demonstrating high levels of GDP growth, region-wide inclusive and sustainable development (ISID) is hindered as the majority of the populations living in rural areas where electricity access is quite low.

Burundi is taking measures to improve the electricity sector through new legislative frameworks, including a reorganization of the sector. It is seeking to develop sustainable energy projects in rural areas. It currently has 12 SHP plants (<1 MW) with a combined installed capacity of 3 MW. However, three of these plants are in need of refurbishment.

Ethiopia has vast potential for hydropower and has been utilizing this resource for the development of large hydropower plants. While the highland topography is well-suited for development of small and micro-hydropower, the sector has been slow to grow (6.18 MW). In order to improve private sector participation, the Ethiopian Electricity Agency (EEA) is currently developing legislation for feed-in tariffs which is expected to spur activity in the sector.

Hydropower plays the most significant role in the generation of electricity in Kenya. While SHP represents only a small fraction of overall national electricity capacity, the country has created an environment conducive to the development of SHP projects and currently has almost 200 MW in various stages of planning.

Madagascar has the third highest installed capacity of SHP in the region with more than 30 MW in operation.

Currently, the Government plans to install at least 63 MW of additional SHP capacity, of which 15 MW are set to replace existing thermal plants. The national energy policy, which was adopted in 2015, includes renewable energy targets and incentives for private sector participation in the sector.

Malawi has four operational SHP plants, the largest of which is the Wovwe (4.5 MW) while the remainder are mini or micro plants. Micro-hydropower could be the key to increase rural electrification, as micro-hydro potential is estimated at 15.6 GWh. The Government is currently updating its national energy plan to include incentives for SHP and other renewable energies (RE) development.

SHP in Mauritius represents 20 per cent of the total hydropower generation. The Central Electricity Board owns and operates all SHP plants on the island (9.3 MW). The private sector also plays a vital role in electricity generation in the country, particularly in regards to renewable energy. The Government has issued feed-in tariffs for renewable energy RE) and has imposed taxes on fossil fuels, as part of its long-term goal of becoming energy independent.

The legal framework for foreign investment and renewable energy is currently under review in Mozambique. The Government plans to double its RE capacity as set forth in its Sustainable Energy for All (SE4ALL) objectives. With a Water Policy which encourages the use of SHP, private developers will be able to increase the existing capacity (which is 2.3 MW) by tapping into the estimated 1,000 MW potential.

SHP potential in Réunion has been almost fully developed. The island has installed 11 MW of the roughly 11.47 MW of unrestricted potential. However, there are still opportunities for micro-hydropower plants to utilize the remaining potential.

SHP represents nearly half of hydropower generation in Rwanda, or almost a quarter of total generation. The majority of SHP plants are privately owned. Estimates indicate up to 96 MW of micro- and pico-hydropower potential are available and more studies are being conducted.

South Sudan currently has no installed SHP; a 5 MW project was previously being developed but it was halted due to financial constraints. SHP development is included in the Government plan to fast-track growth and recover from conflict by leveraging its vast natural resources. Current estimates of SHP potential indicate at least 24 MW.

Tanzania has 45 SHP plants with an total installed capacity of 25 MW. The majority of the sites are less than 5 MW and have been constructed by donors, missionaries and the Government. Private investors now own 85 per cent of these SHP plants. Current incentives for SHP development include power purchase agreements and specific SHP feed-in tariffs.

Uganda originally issued renewable energy feed-in tariffs (REFIT) in 2007 but after limited investor participation, it revised the scheme again in 2010. Several SHP projects are underway, including one refurbishment and two new installations.

In 2014, the Government of Zambia adjusted tariffs to support reinvestment in the economy. Many SHP plants are being upgraded to larger capacities, e.g. Lunzua from 0.75 to 14.8 MW. Current estimates of the country's SHP potential are very conservative and will likely increase significantly as more studies are being carried out.

In Zimbabwe, the installed capacity of SHP has increased to 7 MW. The development of micro-hydropower has increased in the Eastern Highlands, and the projects have been led by the NGOs Practical Action and OXFAM. Zimbabwe has also opted into the SE4ALL initiative; the Government has set its renewable energy targets in line with the programme for the 2030 horizon.

Barriers to small hydropower development

It has been established that there are a number of barriers which hinder the development of renewable energy, including SHP, in Eastern Africa. While many governments have been exerting efforts to adopt policies to encourage inclusive and sustainable development strategies, the financial aspect remains the major constraint which hinders progress in the development of SHP. Considering the relatively high investment costs for RE projects, especially for remote locations for Rural Electrification projects, the end user often does not have the financial capacity to support the investment.

Project costs can be higher in the region due to an undeveloped RE industry and the lack of resource data. Project developers must often collect data before making decisions about a project. It has been established that some national institutions have varying policies which are expected to hinder the deployment of renewable energy technologies (RET) or delay licensing procedures. However, it is advisable that these institutions should revisit these policies to make them more accommodating to the project developers' plans.

Many RE projects in the region are donor-driven as investment into these economies, perceived as fragmented markets, implies higher risk.

However, major barriers to RE development can be addressed by introducing a number of interventions, one of which is the establishment of a regional (and national) renewable energy policy, to include appropriate incentives for investment.[8]

TABLE 3

SHP in Eastern Africa (+/– % change from 2013)

Country	Potential (MW)	Planned (MW)	Installed capacity (MW)	Annual generation (GWh)
Burundi	61 (+12%)	N/A	15.8 (0%)	119.5 (-)
Ethiopia	1,500 (0%)	N/A	6.2 (0%)	N/A
Kenya	3,000 (0%)	194.0 (-)	32.0 (–3%)	59.0 (-)
Madagascar	>82 (-)	63.0 (-)	30.6 (+36%)	N/A
Malawi	150 (+900%)	0.4 (-)	5.6 (–3%)	N/A
Mauritius	9.7 (+2%)	N/A	9.3 (+7%)	18.2 (-)
Mozambique	1,000 (0%)	N/A	2.3 (+9%)	N/A
Réunion	121 (0%)	N/A	11.0 (0%)	N/A
Rwanda	48.2 (+26%)	24.6 (-)	23.2 (0%)	N/A
South Sudan	24.7 (-)	5.0 (-)	0 (-)	0 (-)
Tanzania	400 (+90%)	28.8 (-)	25.0 (10%)	N/A
Uganda	200 (0%)	9.2 (-)	34.4 (+53%)	352.0 (-)
Zambia	42 (-)	29 (-)	12.9 (-)	N/A
Zimbabwe	120 (0%)	N/A	7.1 (+276%)	N/A
Total	**6,758.6 (+8%)**	**353.95 (-)**	**215.4 (+3%)**	**(-)**

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.
Note: The data is for SHP plants with installed capacity of less than 10 MW SHP as defined by the COMESA with the exception of potential for Uganda (< 20 MW). Please see respective country reports for data by national classification in Burundi, Malawi, Mozambique, Rwanda and Uganda.

1.1.1 Burundi

Jeremy Sinzinkayo, Agence de Contrôle et de Régulation du Secteur de l'Eau Potable et de l'Electricité au Burundi

Key facts

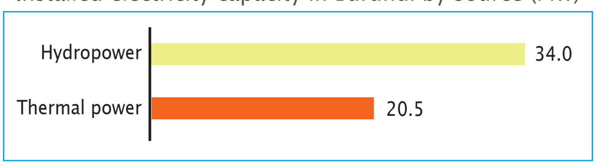
Population	10,816,860[1]
Area	27,834 km²
Climate	Burundi has an equatorial climate and experiences high temperatures near Lake Tanganyika and the Ruzizi River Plain, ranging between 27°C and 32°C during the day and between 21°C and 24°C at night. The central plateau, however, enjoys a cooler climate with temperatures ranging from 18°C to 22°C, while the high mountainous area in the western part of the country experiences the coolest temperatures, ranging between 12°C and 16°C. The capital, Bujumbura, located off the north-eastern shore of Lake Tanganyika (on the western part of the country) experiences an average annual temperature of 23°C.[2]
Topography	Burundi is characterized by mostly plateaus and mountains. The western part of the country is composed of mountain ranges running from north to south, with the highest point being Mount Heha at 2,670 m. The only plains in Burundi exist along the Ruzizi River, north of Lake Tanganyika, and form the western border with the Democratic Republic of the Congo.[2]
Rain pattern	There are two seasons in Burundi: a wet season that lasts from October to April and a dry season that last from May to September. The wettest month is usually April while the driest is usually July. The average annual rainfall is 848 mm.[3]
General dissipation of rivers and other water sources	Burundi has four major rivers: Kanyaru, Malagarasi, Rusize and Ruvubu Rivers. It also has three major lakes: Cohaha, Rwero and Tanganyika Lakes.[4] The rivers of Burundi, apart from being sources of water for the country, are also utilized for the generation of hydroelectric power. The fast-flowing Burundi rivers can offer an abundant supply of power if utilized properly as renewable energy source.[5]

Electricity sector overview

Burundi has a total installed generation capacity of 55 MW. There is approximately a 5 per cent electrification rate, with 2 per cent access to electricity in the rural areas and 28 per cent in the urban areas of its capital, Bujumbura.[6] This is a sharp decrease from the 2012 electrification rate which was at 10 per cent at the national level, with 7 per cent in rural areas and 34 per cent in the urban areas. The installed capacity consists of approximately 33.84 MW of hydropower,[13] a 5.5-MW reserve diesel plant for Bujumbura (with an additional 5 MW extension in 2013), and 10 MW of smaller diesel generators.[6,17,18] The remaining source of electricity generation comes from energy imports. Burundi plans to obtain an additional 7.5 MW from solar energy in 2016.[7]

FIGURE 1

Installed electricity capacity in Burundi by source (MW)



Sources: IEA,[6] Gigawatt Global,[7,17] Ministry of Energy and Mines,[13] REGIDESO[18]

The country's electrical power is traditionally state-owned. Structural adjustment and privatization for the power sector initially commenced in 1989 but the civil and political conflict has curtailed the process.[8] Electricity generation and supply in Burundi is managed and administrated by two primary organizations and one sub-government agency. The first organization, Regie de Production et Distribution d'Eau et d'Electricite (REGIDESO), is a state-controlled company that operates and controls all thermal power stations and 96.5 per cent of the installed hydropower.[8,9] REGIDESO is also responsible for power and water distribution in urban and rural areas.[8]

The Burundian Agency for Rural (ABER; formerly known as DGHER), a government agency and customer of REGIDESO, is responsible for water distribution and electrification of rural areas. The second primary organization is the International Society for Electricity in the Great Lakes Region (SINELAC) which is a multinational organization comprising the Democratic Republic of the Congo (DRC), Burundi and Rwanda as the three shareholders. It is responsible for developing international electricity projects which include the Rusizi hydro plant situated in Burundi and the DRC, and the Rusizi II which is situated in Burundi the DRC and Rwanda. These two regional

TABLE 1

Operational hydropower plants in Burundi

Name	Location	Capacity installed or imported (MW)	Energy produced (GWh/year)	Estimated cost of production (US$/kWh)	Operator	Implementation date
Imports						
Rusizi I	International – Burundi – DRC	3	34	0.029	SNEL	1958
Rusizi II	International – Burundi – DRC –Rwanda	13.3	73	0.043	SINELAC	1989
Subtotal		16.3	107			
National production						
Rwegura	Kayanza	18	55	0.04	REGIDESO	1986
Mugere	Bujumbura	8	40	0.04	REGIDESO	1982
Nyemanga	Bururi	2.88	24.4	0.04	REGIDESO	1987
Ruvyironza	Gitega	1.5	11	0.04	REGIDESO	1980
Gikonge	Muramvya	1	6.8	0.04	REGIDESO	1982
Kayenzi	Muyinga	0.85	1.3	0.04	REGIDESO	1984
Marangara	Kirundo	0.25	2	0.04	REGIDESO	1986
Buhiga	Karuzi	0.24	—	—	REGIDESO	—
6 stand-alone hydropower plants	Various	0.47	—	—	ABER	—
12 private hydropower plants	Various	0.65	—	—	Private (the Burundi Tea Office and religious missions)	—
Subtotal		33.84	140.5			
Total		**50.14**	**247.5**			

Source: Ministry of Energy and Mines[13]

hydropower plants generate electricity for all three countries but it especially compliments the domestic generation of Burundi, accounting for 40 per cent of its national consumption.[10] Further, the SINELAC has initiated several hydro projects which are presently under construction.[8]

In addition to the stunted supply-deficit in the country, the conditions of the power plants are also substandard, often producing technical as well as non-technical losses of power of approximately 20-30 per cent.[9] In effect, this means that those 5 per cent of citizens, including the business owners, with access to electricity face constant power outages. As a result, many business owners invest in backup generators or share access to one, costing them approximately US$0.40 to US$0.50/kWh. The costs of the backup generator are often appropriated directly from business profits, thus reducing business viability in domestic, regional and international market competition.[9] Power cuts, therefore, are one of the main obstacles to economic growth in the country.

The electrical transmission system is made up of 750 km of high-voltage lines (110 kV) and medium-voltage lines (30 kV),[10] over which REDIGESO has exclusive responsibility. The transmission network was set up before the civil wars and as a result, it is extremely outdated and requires urgent rehabilitation work. Burundi is a member of the Eastern Africa Power Pool (EAPP) which has a mission for electrical interconnectivity to connect all East African countries from Tanzania to Egypt. This linkage would allow for more flexible import and export of electricity between the countries in the region. However, the current transmission network in Burundi is not adequate for an interconnected system. The current 110 kV lines would need to be replaced with 220 kV lines in order for Burundi to effectively connect its national grid with the regional power lines of the EAPP.[10]

Tariffs from REGIDESO have increased since 2012. In 2012, the average tariff was 0,006 US$/kWh while the prices reached 0.10 US$/kWh in 2013 (Table 1). The Government of Burundi and REGIDESO are planning to include additional tariffs in order to balance the cost of the component fuel, specifically with thermal generation. However, both entities must first address the issues regarding the collections of tariffs which are currently causing a financial deficit for each kWh sold.[11] Lastly, the demand of electricity is growing at an accelerated pace

TABLE 2

Electricity tariffs in Burundi

	Tariff (BIF/kWh)	Effective price (BIF/kWh)	Tariff (USD/kWh)	Effective price (USD/kWh)
BT household (<100 kWh/2 months)	73.00	86	0.046	0.054
BT household (100-300 kWh/2 months)	138.00	163	0.086	0.102
BT household(>300 kWh/2 months)	260.00	312	0.163	0.195
BT commercial (<300 kWh/2 months)	93.00	138	0.058	0.086
BT commercial (300-1,000 kWh/2 months)	149.00	193	0.093	0.120
BT commercial (>1,000 kWh/2 months)	190.00	234	0.119	0.146
Administration	149.00	149	0.093	0.093
Public lighting	151.00	151	0.094	0.094

Source: The Duke Center on Globalization, Governance and Competitiveness[10]

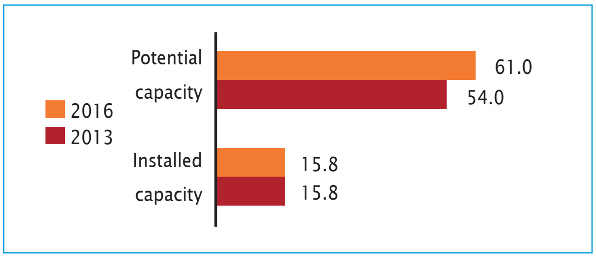
in Burundi. If the country is able to eliminate an unserved demand of electricity of up to 36 per cent and increase household access from 4 per cent to 35 per cent in the coming years, electricity demand will increase by at least 10 per cent per year. This equates to a rise of 92 MW and 450 GWh by 2018, and 192 MW and 933 GWh by 2025.[11]

Small hydropower sector overview and potential

The definition of SHP in Burundi requires SHP plants to have a generation capacity of up to 1 MW.[12] If one regards the national definition of a capacity of up to 1 MW, then Burundi has a small or micro-hydropower potential of approximately 30.5 MW and an installed capacity of 3.1 MW.[13] However, with regards to the normative classification of small hydropower (SHP) as installed capacity of up to 10 MW, the installed capacity in Burundi is 15.84 MW while the potential, as determined from planned SHP, is 61 MW.[13]

FIGURE 2

SHP capacities 2016-2013 in Burundi (MW)



Sources: *WSHPDR 2013*,[15] Ministry of Energy and Mines[13]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*. The data is SHP plants with installed capacity of less than 10 MW.

Burundi currently has 12 hydropower plants of less than 1 MW. Six of the 12 are operated by ABER and of these six, two are not functional and one requires substantial technical maintenance.[10] The Government has reportedly identified 30 sites that are optimal for micro-hydropower plants. However, as of now, it does not have the financial capabilities to build them.[14] Furthermore; the Government also has had difficulty identifying more viable sites for small or micro-hydropower as it currently does not have the funds or human capital to conduct such studies.[14]

The hydropower potential in the country, inclusive of small and large hydropower plants, has been evaluated at approximately 1,700 MW.[10] Of the 1,700 MW, at least 404 MW are economically viable.

Renewable energy policy

The Government is implementing policies and regulations to improve the renewable energy sector in the country. The goal is to improve the economy, reduce poverty and give more readability to the incomes obtained from the renewable energy sector.

The strategy for developing the renewable energy sector relies on the following points:

- Improvement of the legislative and institutional framework;
- Sustainable development of rural communities within the framework Energie Durable Pour Tous (Sustainble Energy for All);
- Implementation of a law aiming to reorganize the electricity sector in Burundi;
- More transparency in order to shed light regarding the impact of the renewable energy for the country's economy;
- Liberalization of the renewable energy sector.

The Government of Burundi has requested assistance from several international organizations including the United Nations Development Programme, the European Union and the World Bank in order to prepare feasibility studies. Burundi made major reforms in 2011 to improve its business climate. Procedures for creating a business and obtaining construction permits have been substantially carried out. The ratification of the Treaty for the Establishment of the East African Community compels Burundi to adopt national laws to ensure the strict application of the rules of the treaty.[10] Burundi now belongs to the East African Community (EAC) towards a Common Market, consisting of Kenya, Tanzania, Uganda, Rwanda and Burundi; all of which are in favour of commercial trade between member states.[15] Burundi has also implemented the following laws that aim to further liberalize the electricity sector:[15]

- Law No. 1/23 of 24 September 2008 defined all the tax benefits for investors in Burundi.
- Law No. 1/177 of 19 October 2009 established the Investment Promotion Agency which aims to promote investment and exports; and especially to inform, assist and support investors in obtaining all the necessary documents in compliance with formalities as required by law. The agency will also participate in the discussion of reforms to improve the business climate.
- Law No. 100/318 of 22 December 2011 established a rural electrification agency, called the Burundian Agency for Rural Electrification (ABER; replacing the agency DGHER) to develop and implement rural electrification projects and programmes including small-scale hydropower, solar and wind energy, as well as other forms of energy that can improve electricity access for the rural population.
- Law No. I/013 of 23 April 2015 aims to reorganize and liberalize the electricity sector.

Barriers to small hydropower development

Burundi has made important improvements to the business sector and has made efforts to liberalize the renewable energy sector. In order to keep improving the business climate, however, the legal and institutional framework needs to be reinforced in a framework favourable to the sponsors.

1.1.2 Ethiopia

Nebiyu Bogale, Jimma Institute of Technology of Jimma University

Key facts

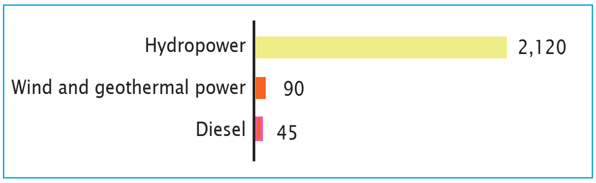
Population	99,805,831[1]
Area	1,104,300 km[2]
Climate	A tropical monsoon climate with three distinct climate zones according to elevation; the hot tropical zone (lowlands) has an average annual temperature of 27°C. The subtropical (temperate) zone includes some highland areas and has an average temperature of about 22°C. The cool zone is above 2,440 m with an annual average temperature of 16°C.[1]
Topography	The tropical zone is between 0 and 1,830 m above sea level, subtropical zone includes the highland areas between 1,830 and 2,440 m, and the cool zone is above 2,440 m in elevation in the western and eastern section of the high plateaus.[1]
Rain pattern	The tropical zone has annual rainfall of about 510 mm. The subtropical zone includes the highlands with rainfall between 510 and 1,530 mm while the cool zone has annual rainfall between 1,270 and 1,280 mm.[1]
General dissipation of rivers and other water sources	Ethiopia has nine major rivers and 12 big lakes. Lake Tana in the north, for example, is the source of the Blue Nile. However, apart from the big rivers and major tributaries, there is hardly any perennial flow in areas below 1,500 m.[9]

Electricity sector overview

Installed capacity in Ethiopia in 2013 was 2,255 MW of which, 94 per cent (2,120 MW) was from hydropower, 4 per cent (90 MW) wind and geothermal and the remaining 2 per cent (45 MW) from stand-alone diesel generators (Figure 1).[2] The electricity generation in 2013 was 8,719 GWh. The total length of the existing transmission line is approximately 10,884.23 km[2].

FIGURE 1

Installed electricity capacity in Ethiopia by source (MW)



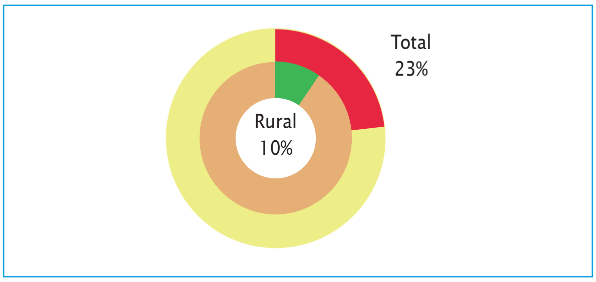
Source: Ministry of Water and Energy[2]

An 80 per cent of Ethiopians live in rural parts of the nation and among the rural villagers, only 10 per cent have access to electricity while the electrification rate in urban centres is 85 per cent (Figure 2).[10]

Ethiopian Electric Power Corporation (EEPCo) is the electricity supplier in Ethiopia; it is also responsible for setting the tariffs for electricity. The national electricity price is fixed at US$0.04/kWh. Since 2002, the corporation has subsidized 35 per cent of household consumption. The Government policy has been to ensure access to energy to the poor. However, the reality is that most of the poor do not have access to electricity. In addition, the lower cost of electricity is a disincentive for private and foreign companies to invest in this sector. To solve this problem, the Government is working on changes in national tariffs to attract the interest of investors. This new tariff is expected to be implemented in the near future.[7]

FIGURE 2

Electrification rate in Ethiopia



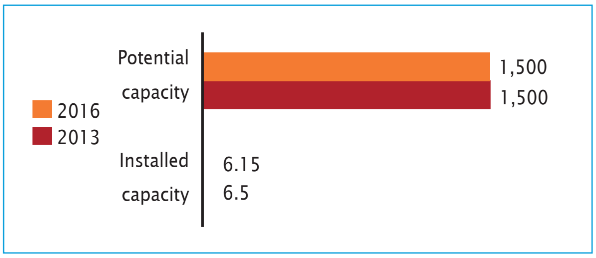
Source: IEA[10]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Ethiopia is up to 10 MW. Installed capacity of SHP is 6.183 MW while the potential is estimated to be 1,500 MW, indicating that less than 1 per cent has been developed.[8,12] Since the publication of *World Small Hydropower Development Report* (*WSHPDR*) *2013*, the installed capacity has increased by 0.5 per cent, while estimated potential has not changed (Figure 3).

FIGURE 3

SHP capacities 2013-2016 in Ethiopia (MW)



Sources: *WSHPDR 2013*,[4] GIZ,[8] IRENA[12]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

According to Alphasol Modula Energy, pico- and micro-hydropower plants are classified for power generation systems ranging from 0.1 to 100 kW and from 100 to 500 kW respectively. Mini- and small hydropower systems are 500 kW-10 MW and medium and large power plants are above 10 MW.[9]

The highland topography with scattered households and demand of large cultivated land of Ethiopia as well as the large number of annual flowing small rivers is well suited for development of small and micro-hydropower. Due to the seasonal rainfall, the potential for small-scale hydropower is estimated to be 10 per cent of the overall potential. Most of the sites are located in the western and south-western parts of the country so the potential capacity varies according to the annual rainfall which ranges from 300 mm to over 900 mm.

In May 2013, Jimma University under its community service duty collaborated with Alphasol Modula Energy PLC and the community to develop a plant with a generating capacity of 15 kW. In addition, Jimma University in collaboration with GiZ-ECO, Agricultural Mechanization Research Institute as well as Zonal Water and Energy Office finalized an 18 kW hydropower project in December 2014.

In February 2012, three micro-hydropower plants with a cumulative capacity of 125 kW were inaugurated in the villages of Ererte, Gobecho and Hagara Sodicha in Sidama zone in the Southern Nations, Nationalities and the Peoples' Regional State (SNNPR).

According to a 2010 German Agency for Technical Cooperation Report, small and micro-hydropower are not yet developed on a larger scale. Three SHP schemes exist in Yadot (0.35 MW), Dembi (0.8 MW) and Sor (5 MW) with a national cumulative installed capacity of at least 6.18 MW.[8]

The market for mini and SHP depends on the ability to feed into the grid. The Ethiopian Electricity Agency (EEA) is currently developing a FIT to encourage developers to participate in the development of local resources to generate and sell power. In this regard, a conservative estimation of the market potential for additional capacity is on the order of 1,000 MW, considering that only 30 per cent of the technical potential is feasible due to accessibility and distance from the grid.

In the mid to long term, it is believed that the current efforts in developing micro and pico-hydro schemes with the support from donors will set a momentum that encourages developers to see opportunities in mini- and SHP resources. Moreover, the FIT law, which is under development at the moment, is expected to be effective in the near future. This will create a market for mini- and small hydropower plants unfolding more interesting business opportunities for private companies.[8]

Renewable energy policy

Ethiopia has an exploitable hydropower potential of approximately 45 GW. In addition, the country has 7 GW of potential from geothermal, 4-6 kWh/m^2 average solar radiation, 1,350 GW from wind.

The Ethiopian Government (GoE) energy policy was issued in May 1994 with the objective of ensuring a reliable supply of energy at an affordable price, particularly to support the country's agricultural and industrial development strategies. The key features of this policy are the promotion of the role of the private sector in the electricity generation and the establishment of a regulatory authority, i.e. EEA. One of the energy policy priorities is the enhancement and expansion of the development and utilization of the country's immense hydropower resources. Energy policy measures in the power subsector include national capacity building in engineering, construction, operation, and maintenance and the gradual enhancement of local manufacturing capability of electro-mechanical equipment and appliances.[8,9]

The legal framework for investment in the power sector has been amended and revised. Investment legislation has liberalized the electricity sector by allowing domestic and foreign investors to invest in hydropower of any size. All investment proclamations and regulations confirm that power transmission and distribution still remains under the monopoly of the EEPCo.

The establishment of the EEA was another landmark in the development of the power sector. EEA is responsible for issuing operational licence for power generation, recommending tariffs and setting technical standards.

However, the absence of a legal framework such as Power Purchase Agreements (PPA) or FIT has limited power generation by the private sector only to off-grid users. As the grid expands to nearby off-grid areas, existing off-grid power generation plants (i.e. SHP or diesel generator sets) will be simply abandoned. This has a further consequence of investment risks. EEA is now drafting a FIT law which is believed to resolve such investment risks and also provides opportunities to investors to revive abandoned small and micro-schemes or develop new potential sites within the grid-covered areas.

The FIT for renewable energy is drafted and it is expected to be implemented by the electricity regulatory agency in the year 2016. The Rural Electrification Fund (REF) provides concessional loans for the development of off-grid electrification projects. The loan amounts to 85 per cent of the total investment with an interest rate of 7.5 per cent for diesel projects and 95 per cent loan with zero interest rate for renewable energy projects.

Legislation on small hydropower

An environmental impact assessment (EIA) is required for all hydropower plants. However, an exception is made for micro-hydropower as the requirement for these systems is waived by the regulating authority. If the micro-hydropower project is supported by a loan from the rural electrification fund, then such assessment and approval from all neighbouring upstream and downstream countries is required (as per regulation by the World Bank). Another requirement for off-grid plants and those connected to mini-grids is a distribution licence, which can be obtained from the regulator. An investment licence is also required (except for cooperatives) and water rights must be approved by the Ministry (if the owner is not the community which typically possesses the water rights).[11]

Barriers to small hydropower development

- The absence of rules for decentralized energy production and management;
- Low feed-in tariff which results in loss of interest for local and foreign investors;
- Poor government participation in the development of renewable energy technologies that can be locally manufactured and installed (i.e. the Government should work in collaboration with the higher education institutions);
- Lack of local manufactures and entrepreneurs working in the area of SHP;
- Low level of participation by local and international GO and NGOs;
- An increasing population creates more demand for water.

1.1.3 Kenya

Harrison Masiga, Practical Action

Key facts

Population	45,925,301[1]
Area	580,367 km[2]
Climate	Kenya lies on the equator and climatic conditions range from tropical humidity on the coast, dry heat of the hinterland and northern plains and cool plateaus and mountains. Temperatures average between 20°C and 28°C. Seasonal variations are distinguished by duration of rainfall rather than by changes of temperature.[2]
Topography	Low plains rise to central highlands bisected by the Great Rift Valley. The highest mountain, Mount Kenya, is also the second highest mountain in Africa with an altitude of 5,199 m above sea level.[2]
Rain pattern	There are two rainy seasons: March to May and October to early December. Average annual rainfall varies from 130 mm a year in the most arid regions of the northern plains to 1,930 mm near Lake Victoria. The coast and highland areas receive an annual average of 1,020 mm.[2]
General dissipation of rivers and other water sources	Most rivers and streams in Kenya originate in the highlands and flow either east toward the Indian Ocean, west to Lake Victoria or north to Lake Turkana. The two largest perennial rivers are the Tana (724 km) and the Athi-Galana-Sabaki (390 km) Rivers. Both empty into the Indian Ocean.[2]

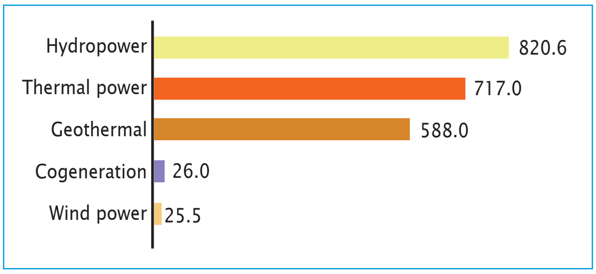
Electricity sector overview

Biomass, petroleum and electricity dominate the energy mix in Kenya. Traditional wood fuel represents approximately 70 per cent of the energy consumption in Kenya, while petroleum and electricity account for 21 per cent and 9 per cent respectively.[3]

As of March 2015, the total installed electricity capacity was 2,177 MW, and comprised hydropower (approximately 38 per cent), thermal (33 per cent), geothermal (27 per cent), cogeneration (1 per cent) and wind (1 per cent) (Figure 1).[4]

FIGURE 1

Installed electricity capacity in Kenya by source (MW)

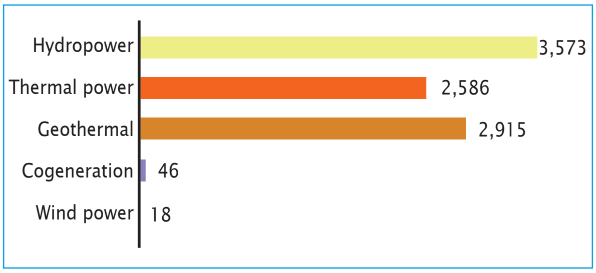


Source: Energy Regulatory Commission[4]

In 2014, the total generation was 9,138 GWh.[5] Though still dominated by large hydropower, which contributed approximately 39 per cent, the generation mix has seen the introduction of other renewable sources with geothermal plants contributing 32 per cent. Conventional plants contributed 28 per cent of the total, while cogeneration and wind plants contributed less than 1 per cent combined (Figure 2).

FIGURE 2

Annual generation by source in Kenya (GWh)



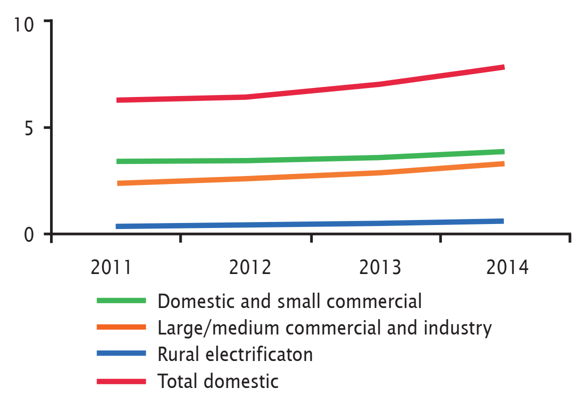
Source: Kenya National Bureau of Statistics[5]

The total electricity consumed in 2014 was 7,769 GWh, which was marginally higher than the previous year's, a growth trend that has been consistent for the last decade. Approximately 50 per cent of the electricity was consumed by the large and medium industry and commercial sector and 42 per cent by domestic and small commercial businesses. Rural electrification consumed approximately 7 per cent. Consumption trends from 2011 to 2014 are given in Figure 3.

In 2013, the national electrification rate was approximately

FIGURE 3

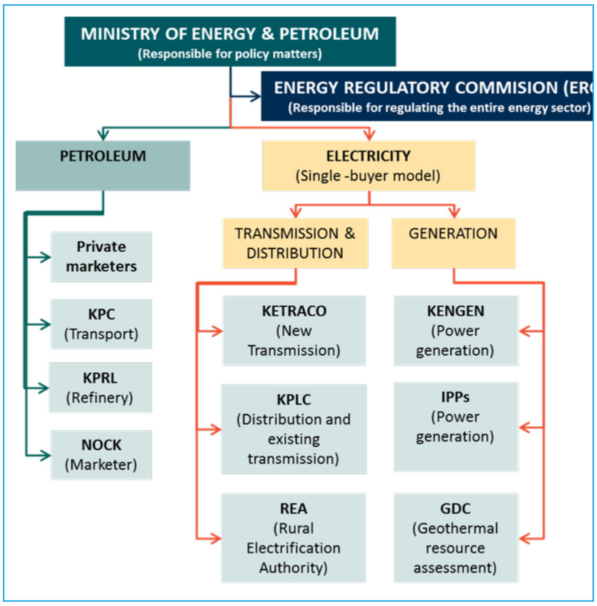
Annual electricity consumption by sector in Kenya 2011-2014 (GWh)



Source: Kenya National Bureau of Statistics[5]

FIGURE 4

Organizational chart of the electricity sector of Kenya



Source: Institution of Engineers of Kenya[9]

20 per cent with the access rate in rural areas relatively low, at 7 per cent.[6] The relatively low electrification rate exists despite the national grid providing access to over 68 per cent of Kenyan households, in part due to some counties having nearly 50 per cent of unconnected households located within the grid coverage area.[7] Off-grid lighting programmes, including the International Finance Corporation (IFC) and the World Bank's Lighting Africa, have encouraged an increased uptake of alternative energy sources especially in areas with no grid presence. With no reliable data on the exact use of off-grid systems, such as solar lanterns and solar home systems, it is difficult to accurately estimate the size of the population currently making use of these energy access solutions.

The country's electricity sector is characterized by a tight demand-supply balance. This is against a backdrop of a low national electrification rate, ever-increasing domestic energy demand, frequent power outages and fluctuations, and an over-reliance on large hydropower generation operating under average hydrological conditions. The electricity sector has, however, been undergoing significant changes in the past decade with the Government keen on diversifying the generation mix into other energy sources.[8] This is complimented and evidenced by fairly active independent power producer (IPP) participation in the sector.

The Ministry of Energy and Petroleum (MoEP) is the lead government institution for energy policy formulation and sector planning. It is charged with overall leadership and oversight in the implementation of national energy plans. The Energy Regulatory Commission provides oversight roles in the sector by developing and enforcing sector regulations. The structure of the energy sector is shown in Figure 4. Apart from MoEP, other key notable organizations in the sector include the following:

- The Energy Tribunal, which is responsible for arbitration of disputes between the Energy Regulatory Commission and aggrieved stakeholders in the energy sector;
- Energy Regulatory Commission (ERC), which regulates all energy subsectors, protects the interests of stakeholders ensuring reasonable return on investment for developers/utilities, licenses, approves PPAs between KPLC and power generators, and reviews and adjusts tariffs for consumers and IPPs;
- Rural Electrification Authority (REA), which implements rural electrification programmes through grid extension and off-grid systems such as solar and mini-hydropower. REA administers and manages the Rural Electrification Fund (REF), mobilizes funds to support rural electrification, finances project preparation studies for rural electrification and recommends suitable policies to the Government;
- Kenya Electricity Generating Company (KENGEN), which develops and manages all public power generation facilities in the country (large and small hydro, geothermal, diesel-grid connected or off-grid);
- Kenya Power and Lighting Company (KPLC), which is a public company that transmits, distributes and retails electricity to customers in Kenya;
- Kenya Electricity Transmission Company (KETRACO), which plans, designs, builds and maintains electricity transmission lines and associated substations;
- Geothermal Development Corporation (GDC), which is a government SPV charged with fast-tracking development of geothermal resources in the country;
- Independent Power Producers, which are private companies licensed by ERC to generate and sell power to the national utility through power purchase agreements. Collectively, they account for about 2 per cent of the country's installed capacity.

The liberalization of the electricity sector through the Electric Power Act of 1997 and the subsequent introduction of FITs in 2008 for renewable energy projects have generated significant interest from the private sector. The policy shift, aimed at promoting private sector investment in energy and which has since resulted in the development of a Standard Power Purchase Agreement (SPPA), has been successful with six IPPs already operational in the country.[11]

The electricity supply industry structure remains that of the single-buyer model with all generators selling power in bulk to KPLC for onward distribution to consumers.[12] The transmission network is partly owned by KPLC (for all existing infrastructure before 2008) and KETRACO. The total transmission network comprises 1,434 km of 220 kV and 2,513 km of 132 kV lines while the distribution network is composed of 1,212 km of 66 kV lines, 20,778 km of 33 kV lines and 30,860 km of 11 kV and low-voltage lines.[13] The main trunk lines connect generation plants to major demand centres. The power generation plants are, however, unevenly distributed across the country. This presents a major system constraint highlighting the inadequacy of the interconnected grid for power transfers in the country.

Efforts are, however, being put in place to strengthen the transmission system network through maintenance and development of new transmission lines and adoption of N-1 criterion in all new designs to create some redundancy capacity.

Future planning for the electricity sector is based on the 10-year Power Expansion Plan between 2014 and 2024 which focuses on load forecasting, generation and transmission planning. The plan deliberately incorporates renewable energy into the projected generation mix, in particular focusing on projects approved under the FIT. The demand forecast considers the needs of accelerated investment under the Vision 2030 economic blueprint and estimates a supply gap of 10,000 MW by 2024. The total generation expansion cost required is estimated at US$25.873 billion.[14]

The ERC is charged with the regulation of electricity tariffs within the country. While the utility company periodically revises electricity tariffs based on an ERC-approved formula, revised tariff schedules must be approved by the regulator before enforcement. Different tariffs apply to different user categories, i.e. domestic, industrial, commercial, and government premises but do not vary with geographical location. Tariffs as of July 2015 are given in Table 1.

Small hydropower sector overview and potential

The energy policy of 2004 defines small hydropower (SHP) as run-of-river power plants with installed capacities below 10 MW. These are further broken down into small, micro or pico hydropower.

It is estimated that at least 3,000 MW of potential SHP capacity exists in Kenya.[16] However, only approximately 32 MW is currently installed, representing 5 per cent of the total installed hydropower capacity in the country. This indicates that approximately only 1 per cent of SHP potential has been developed. Compared to the *WSHPDR 2013* potential capacity has remained the same while installed capacity has decreased slightly by 1 MW due to the decommissioning of a plant (Figure 5).[16]

Existing SHP plants have varying ownership structures including private, community or public ownership models. Most of the commercial and public plants are operational and generally in good condition while most of the community schemes are in need of significant refurbishment. A summary of existing plants is provided in Table 2.

In fiscal year 2013-2014, the total power purchased from existing grid-connected SHP plants was 59 GWh.[17] This is expected to grow with increased private sector interest in the sector.

Potential sites are mostly concentrated in central, Rift

TABLE 1

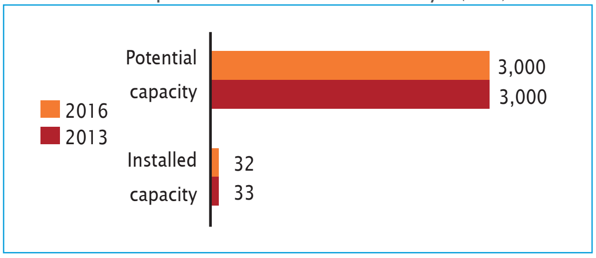
Consumer tariffs in Kenya from July 2015

Tariff	Charges (Kenyan shillings (US$))			
	Fixed charge	Energy charge (per kWh)		Demand charge (per kVA)
DC (Domestic, 240 V)	150 (1.8)	Up to 50 kWh:	2.5 (0.03)	—
		50 to 1,500 kWh:	12.75 (0.153)	
		Above 1,500 kWh	20.57 (0.24684)	
SC (Small commercial, 240 V)	150 (1.8)		13.5 (0.162)	—
CI1 (Commercial, 415 V)	2,500 (30)		9.2 (0.1104)	800 (9.6)
CI2 (Commercial, 11 kV)	4,500 (54)		8 (0.096)	520 (6.24)
CI3 (Commercial, 33 kV)	5,500 (66)		7.5 (0.09)	270 (3.24)
CI4 (Commercial, 66 kV)	6,500 (78)		7.3 (0.0876)	220 (2.64)
CI5 (Commercial, 132 kV)	17,000 (204)		7.1 (0.0852)	220 (2.64)
IT (Domestic water heating)	150 (1.8)		13.5 (0.162)	—

Source: Energy Regulatory Commission[10]

FIGURE 5

SHP capacities 2013-2016 in Kenya (MW)



Sources: Ministry of Petroleum and Energy,[11] Balla,[16] *WSHPDR 2013*[15]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

Valley and western Kenya. Coincidentally, with the exception of western Kenya, these regions also have relatively high electrification levels. A number of potential sites across the country are currently at advanced stages of pre-development with the notable presence of private investors such as Virunga Power, ResponsAbility Africa, Frontier, VS Hydro and Gulf Energy. Potential sites marked for development by the private sector in the medium term include Broderick Falls, Mutunguru, Mathioya Cascade and Yala Falls. According to the ERC, a total of 44 proposals for development of SHP projects under the FIT scheme with a total capacity of 194 MW had been approved by June 2014 with many more still under consideration.

The Government has commissioned a national resource assessment for SHP alongside conducting feasibility studies for potential sites in order to attract private sector investment. It is expected that sites with confirmed technical and financial viability will be offered to private investors through public auctions for development.

The Kenya Association of Manufacturers (KAM) runs a Regional Technical Assistance Programme (RTAP) aimed at catalysing financing for renewable energy projects in East Africa. RTAP's objective is to make renewable energy and energy efficiency financing a standard business model

TABLE 2

Operational SHP plants in Kenya

Plant	Year constructed	Developer	Installed capacity (MW)
Ndula	1925	KPLC	2.00
Mesco	1933	KPLC	0.35
Sosiani	1952	KPLC	0.40
Sagana Falls	1955	KPLC	1.50
Gogo Falls	1958	Mining Co.	2.00
Tana 1 & 2	1952	KPC	4.00
Tana 3	1952	KPC	2.40
Tana 4	1954	KPC	4.00
Tana 5	1955	KPC	2.40
Tana 6	1956	KPC	2.00
Wanjii 1 & 2	1952	KPC	5.40
Wanjii 3 & 4	1952	KPC	2.00
James Finlay 1	1934	James Finlay	0.30
James Finlay 2	1934	James Finlay	0.40
James Finlay 3	1980	James Finlay	0.12
James Finlay 4	1984	James Finlay	0.32
James Finlay 5	1999	James Finlay	1.07
Brooke Bond 1	—	Brooke Bond	0.09
Brooke Bond 2	—	Brooke Bond	0.12
Brooke Bond 3	—	Brooke Bond	0.18
Brooke Bond 4	—	Brooke Bond	0.24
Savani	1927	Eastern Produce	0.09
Diguna	1997	Missionary	0.40
Tenwek	—	Missionary	0.32
Mujwa	—	Missionary	0.07
Community MHPs	2002	—	0.02
Total	—	—	**32.19**

Source: Energy Regulatory Commission[14] that can be adopted by local banks in Kenya, Uganda and Tanzania.[18] The programme, funded by the Africa Infrastructure Trust Fund of the European Union, aims at providing support for the financing of renewable energy projects of SHP, biomass, cogeneration and solar as well as energy efficiency projects in the three East African countries. The programme has a portfolio of 96 projects with SHP dominating the renewable energy segment.

In general, financing for SHP still faces various challenges. 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. Nevertheless, the Government is engaging in efforts to promote the SHP sector and, as a result, 35 plants with a total capacity of 163.7 MW are in various stages of implementation (i.e. in the licensing, construction or negotiation process).[21]

Renewable energy policy

The Government of Kenya is keen to increase the share of renewable energy sources in the country's generation mix. This is evidenced by its relatively friendly policy instruments such as the FIT, duty exemption on renewable energy equipment and increased public investment in geothermal exploration, all of which are aimed at attracting private sector investment. However, with the discovery of fossil fuels in the country including coal deposits in Kitui, oil in Turkana County and natural gas in Wajir, the Government is slowly shifting towards a mixed approach encompassing development of both renewable energy plants and fossil fuel generators.

The Ten Year Power Sector Expansion Plan deliberately seeks to incorporate renewable energy in the country's power sector planning processes with a focus on renewable energy projects approved under the FIT process. The plan gives significant recognition for renewable energy as a supply driver for power in the country. The plan proposes the establishment of an inter-ministerial Renewable Energy Resources Advisory Committee (RERAC) to advise the Government on the management of water towers and catchment areas among other issues.

The Energy Act of 2006 set out a clear strategy for the promotion of renewable energy development and resulted in the formulation of the FITs in 2008. The FITs have since been revised twice with the latest tariffs approved in 2012 (Table 3). The Electricity Licensing Regulations of 2012 contain legal provisions for the development of renewable energy-powered mini-grid schemes by the private sector, even in areas that had been previously licensed to the national utility. Licensing requirements are dependent on the installed capacity of the mini-grid's generator.

To a large extent, government planning on energy development is influenced installation and operation costs. Large hydropower projects of economic potential such as Magwagwa do not balance favourably in the least-cost power development plans due to the relatively high investment costs.[20] This is further worsened by the need for massive relocation due to high population densities in identified project areas and the expected environmental challenges. SHP is less affected by these issues.

The draft energy bill of 2015 proposes to redefine the mandate of the Rural Electrification Authority (REA) so as to incorporate responsibility for steering the development of renewable energy projects in the country. The authority, whose name will be changed to Rural Electrification and Renewable Energy Corporation, will be responsible for promoting renewable energy development in alignment with specific regional government needs.

Legislation on small hydropower

The FITs for SHP plants are given in Table 3. Unlike other renewable energy FITs, the value of the SHP

TABLE 3

Feed-in tariffs for renewable energy projects in Kenya

Plant type	Installed capacity (MW)	Standard FIT (US$/kW)	Scalable portion of the tariff	Minimum capacity (MW)	Maximum capacity (MW)
Wind	0.5-10	0.1100	12%	0.5	10
Hydropower	0.5	0.1050	8%	0.5	10
	10	0.0825			
Biomass	0.5-10	0.1000	15%	0.5	10
Biogas	0.2-10	0.1000	15%	0.2	10
Solar (grid)	0.5-10	0.1200	8%	0.5	10
Solar (off-grid)	0.5-10	0.2000	8%	0.5	1

Source: Ministry of Petroleum and Energy[19]
Note: For values between 0.5 MW and 10 MW, interpolation shall be applied to determine tariff for hydropower

FIT is calculated depending on the precise installed capacity ranging from US$0.105/kWh for plants with a capacity of 0.5 MW to US$0.0825/kWh for plants with a capacity of 10 MW. These are regulated tariffs for the sale of generated renewable energy to the national grid by private developers. The tariffs are standard for various capacity ranges and are subject to review periodically.

Barriers to small hydropower development

Hydropower in general is vulnerable to variations in rainfall and climate change. Recently, this has proven to be a big challenge in Kenya with unpredictable rain patterns that have resulted in power and energy shortfalls.

Financing constraints for renewable energy projects have contributed to the limited investment flows from the private sector to SHP projects in Kenya. While initiatives have been put in place to spur interest from local banks, this evidently has not taken root given the limited number of projects accessing long-term financing by local banks.

The lack of appropriate technical skills in the region has also provided a barrier to investment in SHP. This has hindered both planned and existing SHP projects in the country.

1.1.4 Madagascar

Nathan Stedman, International Center on Small Hydro Power

Key facts

Population	23,571,713[1]
Area	587,040 km[2]
Climate	October to March is the hot and humid season, with the warmest months of December to February reaching an average of 20°C while the coolest months of June through August have an average of 14°C. The temperatures and climate vary in different regions of the country. The Toamasina Province and part of Antsiranana province in the east have a humid tropical climate, as does the Tsaratanana region, albeit in higher altitudes of the plateau (900 to 2,000 m). The Mahajanga province and the northern part of the Toliara province in the western coastal region have a dry tropical climate while the southern part of Toliara province is semi-arid.[2]
Topography	As one of the world's largest islands, Madagascar has a unique topography. The plains of the eastern coastline meet a sharp incline inland as the plateau rises with volcanic peaks and numerous waterfalls. The highest peak is Mount Maromokotro (2,876 m).[2]
Rain pattern	Rainfall varies per region, following the climate differences. The Toamasina and Antsiranana provinces receive upwards of 1,500 mm annually while the southern arid province of Toliara receives only 200 mm.[2]
General dissipation of rivers and other water sources	The rivers begin in the central mountainous plateau region and drain outwards to the coastal areas, in some cases having high flow rates and pass over waterfalls.[2] As an example, the North Mahavavy River (160 km) drops 1,900 m in less than 60 km, in part due to the Andranomafana waterfalls (100 m drop over 4 km).[10]

Electricity sector overview

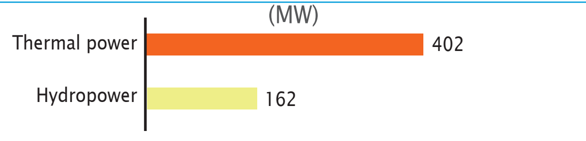
Madagascar is a country with vast untapped renewable energy resources, to include hydropower, wind and solar; meanwhile it has an underdeveloped electricity system that reaches roughly 14 per cent of its 23 million citizens. In 2014, the total installed capacity in Madagascar was 564 MW, with 162 MW of it being hydropower and 402 MW thermal (heavy fuel oil and diesel). The total electricity generation reached 1,487 GWh for the same year,[3] with 884 GWh supplied from hydropower.[12] Biomass (charcoal and wood) represented roughly 93 per cent of the energy supply in 2014 while imported fossil fuels represented roughly 7 per cent; renewable energy accounted for less than 1 per cent the same year. Roughly 80 per cent of energy consumption is for cooking, as 95 per cent of households use wood or charcoal.[4]

The Ministry of Energy and Hydrocarbons (MEH) is the legislative authority of the energy sector, responsible for forming policies and also approving foreign investment. The Electricity Regulation Office (ORE) is the regulator for the electricity sector and facilitates the participation of independent power producers (IPP) while JIRAMA (Jiro sy Rano Malagasy–Malagasy Electricity and Water Utility) is the main utility provider responsible for the electricity supply to the cities and some villages.[4]

JIRAMA operates 114 centres, with an installed capacity of 484 MW (356 MW available). There are three major interconnected grids in Madagascar, the capital of Antananarivo (RIA), Toamasina (RIT) and Fianarantsoa (RIF). Five smaller autonomous grids include Antsiranana, Mahajanga, Nosy Be, Taolagnaro and Toliara.[4]

FIGURE 1

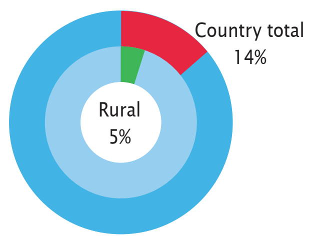
Installed electricity capacity in Madagascar by source (MW)



Source: Ministry of Energy and Hydrocarbons[3]

FIGURE 2

Electrification rate in Madagascar



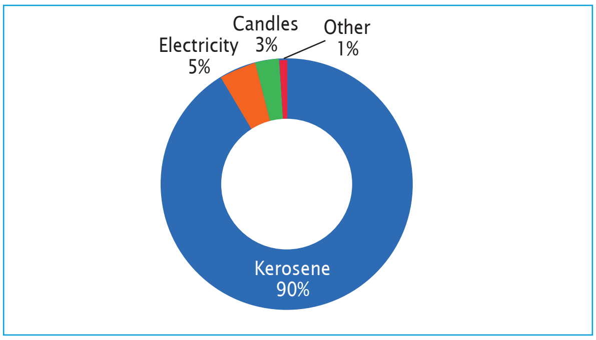
Source: Ministry of Energy and Hydrocarbons[3]

Due to frequent blackouts and shortages, the Government has installed small-scale diesel plants to attempt to relieve demand in the short term. This has increased the share of fossil fuels in the energy mix. However, in the longer term, the Government plans to invest more in renewable energy and replace existing thermal units with hydropower and wind units.

The national electrification rate in 2013 was 14 per cent, with urban centres at roughly 40 per cent and rural areas at 4.8 per cent (Figure 2). As recently as 2010, the majority of the populace in rural areas used kerosene as a source of household lighting (Figure 3).[3]

FIGURE 3

Source of lighting in rural Madagascar



Source: Ministry of Energy and Hydrocarbons[3]

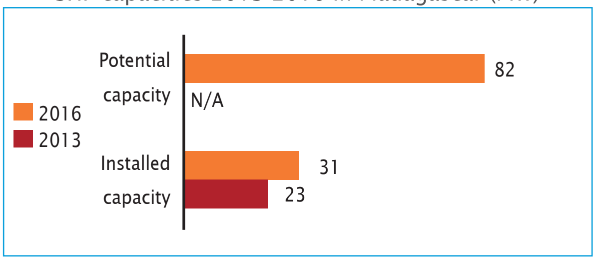
The Agency for Rural Electrification (ADER) is responsible for rural electricity access and extension programmes. With international investment and assistance from the African Development Bank, the German Agency for International Cooperation (GIZ) and the Japanese Government, among others, the rehabilitation of SHP plants has been underway.[4]

Small hydropower sector overview and potential

The theoretical hydropower potential of Madagascar is estimated at 7,800 MW. However, only 162 MW of this is currently exploited, indicating the very high potential for further hydropower utilization. Madagascar currently has 7 hydroelectric power plants, as well as at least 10 small and mini-hydro plants.[3,4]

FIGURE 4

SHP capacities 2013-2016 in Madagascar (MW)



Sources: *WSHPDR 2013*,[8] MEH,[3] EUEI-PDF,[4] ESMAP,[5] ORE[6]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*. The data is for small hydropower plants with installed capacity of less than 10 MW.

While Madagascar does not have an official definition of small hydropower (SHP), the World Bank feasibility study conducted by ESMAP includes hydropower up to 20 MW.[5] Using this definition Madagascar has a SHP installed capacity of 45.63 MW (Table 1).[6] Using the standard 10 MW or less definition, installed capacity would be 30.63 MW. The country-wide total SHP potential capacity has not been identified. However, using feasibility studies and planned SHP installations, an estimated potential can be derived to be at least 82 MW (109 MW for less than 20 MW definition). Since the *World Small Hydropower Development Report (WSHPDR) 2013*, the installed capacity has increased by 30 per cent while potential capacity has been revised to a lower estimate (Figure 4).

TABLE 1

SHP installed capacity in Madagascar

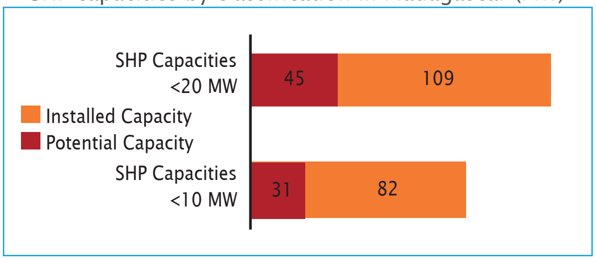
Site location	Grid	MW	Operator	Date
Manandona	Antananarivo	1.6	JIRAMA	1930
Antelomita 1	Antananarivo	4.2	JIRAMA	1930
Antelomita 2	Antananarivo	4.2	JIRAMA	1952
Sahanivotry	Antananarivo	15.0	HYDELEC[b]	2008
Tsiazompaniry	Antananarivo	5.2	HFF[b]	2010
Namorona	Fianarantsoa	5.6	JIRAMA	1980
Manandray	Fianarantsoa	0.5	JIRAMA	1932
Volobe	Toamasina	6.8	JIRAMA	1931
Maroantsetra	Maroantsetra	2.6	HYDELEC[b]	2010
Vatomandry	Vatomandry	0.2[a]	JIRAMA	1953
Total		**45.6**		

Source: Office de Regulation de l'Energie[6]
Note: (a) indicates non-functioning, (b) indicates IPP

One study, spearheaded by the World Bank's ESMAP and in conjunction with the MEH, ORE, ADER and the International Renewable Energy Agency (IRENA), is the Madagascar Small Hydro Atlas. The finalized report is expected by the end of 2016, but initial data indicates that of 1,500 MW of potential SHP in the country (from 350 sites), 130 MW on 20 sites were deemed economically and environmentally feasible. Another study conducted by ADER indicated that some 150 MW of potential was feasible; while this study is older, it can serve as an indicator.[7]

FIGURE 5

SHP capacities by classification in Madagascar (MW)



Sources: *WSHPDR 2013*,[8] MEH,[3] EUEI-PDF,[4] ESMAP,[5] ORE [6]

The review of electricity sector plans from the ORE, ADER and MEH indicates that some 63.4 MW of SHP are already earmarked for installation, some as early as 2016 (Table 2).[3,4,6] This data indicates that the economically feasible SHP potential capacity is between 109 MW and 150 MW and is likely to increase as more studies are completed.

According the plans from the MEH, the ADER and the ORE, the Government will continue to replace existing thermal plants with hydropower, which in large part will be in the form of SHP. In particular, plans for the autonomous grids and the smaller villages indicate SHP will play an increasing role in electricity generation while also bringing access to rural communities.[3,4,6]

TABLE 2

Planned and potential SHP in Madagascar

Site location	Region	Potential (MW)
Bevoy	Diana	6.50
Tsiafampiana	Sava	1.20
Maroantsetra	Sava	2.50
Lokoho 1	Sava	4.00
Lokoho 2	Sava	2.00
Anjialava	Sava	5.00
Lily	Antananarivo	3.50
Mahitsy	Antananarivo	12.00
Namorona	Fianarantsoa	8.00
Andohariana	Sofia	1.50
Bémarivo	Sofia	1.50
Ambodiriana	Atsinanana	0.39
Ampitabepoaky	Bongolava	1.10
Marobakoly	Sofia	0.80
Androkabe	Alaotra Mangoro	1.70
Antanandava	Alaotra Mangoro	1.70
Rianambo	Atsimo Atsinanana	0.40
Andriabe	Melaky	0.60
Sahalanona	Vatovavy Fitovinany	9.00

Sources: MEH,[3] EUEI-PDF,[4] ESMAP,[5] ORE [6]
Note: Sites below the line-break will replace existing thermal plants

Renewable energy policy

The MEH is currently updating the energy policy with the support of the European Union. The new policy is expected to do the following:

- Strengthen the governance framework, the national utility JIRAMA and facilitate private investment.
- Encourage the predominance of renewable sources in the energy mix, at least 5 per cent by 2029, 20 per cent by 2030 and 80 per cent by 2050. The focus will be on both small and large-scale hydro and the development of alternative sources.
- Ensure the sustainable use of natural resources.

With 80 per cent of the national population living in rural areas, the development of rural electrification will be key for the development of the country, a crucial objective for ADER to accomplish.[3] The Government will attempt to do this while at the same time advancing the progress on the Millennium Development Goals (MDG).[3]

Madagascar has not yet been selected as one of the countries under the Sustainable Energy for All (SE4ALL) framework. However, there is significant political will to make progress in both poverty alleviation and creating a more stable energy sector. The Government is working with the EUEI on several fronts, in particular to develop a national energy strategy and policy as well as a new energy policy with renewable energy as a focus.[9]

Currently, there are no feed-in tariffs (FIT) offered by JIRAMA, aside from two IPPs which negotiated a 10-year FIT of US$0.04/kWh. In the case of the Sahavinotry hydro plant, HYDELEC secured a power purchase agreement for a 10-year period.[10]

Barriers to small hydropower development

While the Government continues to work with international experts to conduct feasibility studies and plan new projects, there remain the following barriers to fully exploiting the SHP potential and other renewable energy sources in the country:

- A lack of financial incentives for IPP to participate in the development. A feed-in tariff scheme could improve investor participation.
- A lack of coordination between the institutions and agencies active in the sector as well as with departments of other sectors.
- A lack of coordination between institutions, government agencies and private actors involved in the development of renewable energies.
- Weaknesses in the operation of the regulatory framework.
- Weakness of energy planning process and the evaluation monitoring system for renewable energy.
- Insufficient financial resources to cope with the high investment costs of renewable energy technologies.
- Limited technical and human resources capacity in the energy sector, and more specifically in the renewable energy subsector.
- A lack of private sector mobilization.[3]

1.1.5 Malawi

Gift Chiwayula, Department of Energy Affairs

Key facts

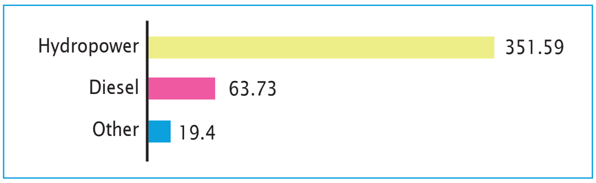
Population	17,215,000[1]
Area	118,484 km[2]
Climate	Sub-tropical with a rainy season from November to May and a dry season from May to November. Variations in altitude lead to wide differences in climate. The mean annual temperature is 24°C with temperatures hottest in November reaching an average daily maximum of 29°C and coolest in July dropping to 23°C.[2]
Topography	Malawi lies within the Great Rift Valley system. Lake Malawi, a body of water 580 km long and 460 m above sea level, is the country's most prominent physical feature. Approximately 75 per cent of the land surface is plateau between 750 and 1,350 m above sea level. Highland elevations rise to over 2,440 m in the Nyika Plateau in the north and to 3,000 m 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 m above sea level.[2]
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 annually.[2]
General dissipation of rivers and other water sources	The main water source 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 the only outlet of Lake Malawi flowing south into Mozambique where it meets the Zambezi.[2]

Electricity sector overview

As of March 2015, the installed capacity was approximately 435 MW with about 80 per cent coming from hydropower plants while the remaining 20 per cent came from diesel generators as well as other small amounts of wind and solar power (Figure 1). Approximately 80 per cent of the country's installed capacity is from the state-owned Electricity Supply Company of Malawi (ESCOM) which operates 10 plants in the country, 7 of which are hydropower plants and 3 diesel (Table 1).[3] According to ESCOM, however, over 50 per cent of the plants have surpassed their life expectancy and require regular maintenance in order to improve their efficiency.[4] The remaining 20 per cent of capacity is privately owned.

FIGURE 1

Installed electricity capacity in Malawi by source (MW)



Sources: Taulo et al.,[3] ESCOM[4]

In 2013/14, the annual generation was 1,906.45 GWh with hydropower accounting for 98 per cent.[4] However, this is far less than the national demand, resulting in a deficient supply. Peak demand on the system is expected to reach 541 MW by 2020 and 629 MW by 2025.[5] An estimated 10 per cent of the total population and only 2 per cent of the rural population in Malawi has access to electricity. The supplied electricity is erratic and subjected to frequent shortages and outages with a lot of load shedding to meet the ever growing demand. Where grid extension is difficult, the Government considers off-grid options such as small and micro-hydropower plants, solar and wind as a viable solution. Most of the country's energy needs are met by the use of biomass, such as fuel wood and charcoal, despite Malawi having considerable access to alternative energy resources such as solar, wind, hydropower and geothermal.[6]

The Government of Malawi is making efforts to increase the capacity of generated electricity by expanding the existing power plants and construction of new power plants. Feasibility studies are currently underway for various energy sources which can be integrated into the energy mix including hydropower sites, coal sites, bagasse resources, geothermal, and wind and solar mapping. The Government plans to increase annual generation to 2,364 GWh by 2020 and to 3,300 GWh by 2025. Plans are also underway to connect to the Zambian and Tanzanian power grids to provide investors with access to the regional power markets.[2]

Electricity Supply Corporation of Malawi (ESCOM) is the sole provider of grid electricity in Malawi. However, the unbundling of ESCOM into three companies for generation, distribution and transmission is in the process and is expected to encourage private players into the electricity sector. Nonetheless there are some private off-grid plants providing electricity from SHP plants (Table 1).

TABLE 1

Operational power plants in Malawi

Plant name	Type	Ownership	Installed capacity (MW)
Nkula Falls B	Hydropower	ESCOM	100.00
Kapichira Falls Phase I	Hydropower	ESCOM	64.80
Kapichira Falls Phase II	Hydropower	ESCOM	64.80
Tedzani Falls III	Hydropower	ESCOM	52.70
Others	Diesel/wind	Private	51.58
Nkula Falls A	Hydropower	ESCOM	24.00
Tedzani Falls I	Hydropower	ESCOM	20.00
Tedzani Falls II	Hydropower	ESCOM	20.00
Nchalo	Bagasse	Private	11.5
Kayerekera	Diesel	Private	10
Dwangwa	Bagasse	Private	7
Wovwe Mini Hydro	Hydropower	ESCOM	4.35
Mzuzu Diesel Unit	Diesel	ESCOM	1.10
Lilongwe	Solar	Private	0.87
Lujeri	Hydropower	Private	0.84
Likoma Islands Diesel Units	Diesel	ESCOM	0.75
Chizumulu Islands Diesel Units	Diesel	ESCOM	0.30
MEGA	Hydropower	Private	0.088
Kavuzi	Hydropower	Private	0.01
Total			**434.69**

Sources: Taulo et al.,[3] ESCOM[4]

The electricity tariffs differ depending on the type of customer and the phase supply being used (Table 2) and are lower than the tariffs from the Southern 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.[4]

In general, the electricity sector faces many challenges such as a lack of independent power producers and a lack of financial resources and clear policy guidelines to promote private investment in the electricity sector. In 2014, the Millennium Challenge Corporation signed a US$250.7 million contract with the Malawi Government in order to help overcome these challenges.[8]

TABLE 2

Electricity tariffs in Malawi

Type of customer	Description	Tariff (US$/kWh per month)
Residential	Single phase supply	0.05
	Three phase supply	0.07
Commercial	Single phase supply	0.08
	Three phase	0.08
Industrial	On peak	0.09
	Off peak	0.02

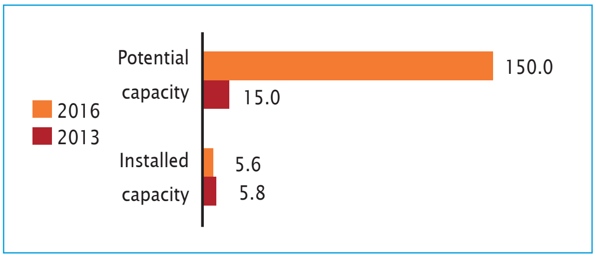
Source: ESCOM[7]

Small hydropower overview and potential

In Malawi, small hydropower (SHP) is defined as plants with an installed capacity less than 5 MW. The total installed capacity for SHP plants less than 5 MW is approximately 5.6 MW with an additional proven potential of at least 7.7 MW and a theoretical estimated potential of 150 MW.[9,10] This indicates that approximately 4 per cent of the country's theoretical potential has been developed so far. Compared to data from the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, the installed capacity has decreased marginally while more data on potential was introduced for this report.[11] However, in regards to the SHP definition of a capacity less than 10 MW, the total SHP installed capacity is still 5.6 MW, as ESCOM has focused on developing large hydropower (Table 1).

FIGURE 2

SHP capacities 2013-2016 in Malawi (MW)



Sources: Various [3,9,10,11]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*. The data is for SHP plants with installed capacity of below 5 MW.

Currently, there is one working SHP plant, which is run by ESCOM, connected to the power utility grid with an installed capacity of 4.35 MW. There are other off-grid SHP plants which are also currently working: Lujeri mini-hydropower plant with a capacity of about 1 MW; Mulanje Electricity Generating Agency (MEGA) with a capacity of 88 kW and Kavuzi mini-hydropower plant with a capacity of 10 kW (Table 1). The MEGA power plant is part of a

TABLE 3

Potential SHP sites in Malawi

District	Site	Distance from grid (km)	River	Estimated flow (m/s)	Estimated capacity (kW)
Chitipa	Chisenga	35	Chisenga	0.1	15
Chitipa	Mulembe	35	Kakasu	0.1	15
Chitipa	Nthalire	102	Choyoti	0.2	60
Rumphi	Katowo	45	Hewe	0.2	45
Rumphi	Nchenachena	23	Nchenachena	0.2	30
Nkhatabay	Khondowe	—	Murwezi	0.05	5
Nkhatabay	Ruarwe	—	Lizunkhuni	0.15	50
Nkhatabay	Usisya	50	Sasasa	0.1	20
Mangochi	Kwisimba	38	Ngapani	0.05	5
Mangochi	Katema	23	Mtemankhokwe	0.1	25
Thyolo	Sandama	6	Nswazi	1	75
				Total	**345**

Source: Chiyembekezo et al.[9]

programme run by Practical Action and is currently undergoing feasibility studies in advance of an upgrade to 2 MW.[12] There are also some SHP plants that are not functioning including one in Matandani, Neno; however, it is being maintained by the Malawi Industrial Research and Development Centre. Funding from the Scottish Government was secured in 2015 and provided for a 100 kW run-of-river scheme near Mulanje.[12] Currently, just 1.6 per cent of the total installed hydropower capacity of 351 MW is from SHP plants.

Malawi has a proven SHP potential of approximately 7.7 MW while a 1997 study by the Ministry of Energy and Mines (MEM) estimated a theoretical potential of 150 MW.[5,10] Practical Action's MEGA project is looking to develop a number of micro-power plants up to 500 kW capacity suggesting that the country's full micro-hydropower potential could generate 15.6 GWh annually. Table 3 shows the SHP potential of 11 sites that have been studied and included in the Malawi rural electrification master plan.[9] Financing mechanisms are limited to either bank loans or small grants from donors such as the Global Environment Facility (GEF).

Renewable energy policy

The Department Of Energy Affairs in Malawi is currently reviewing the National Energy Policy (NEP) which is outdated. The existing NEP aims for renewable energy to contribute 5 per cent to the energy mix by 2020. It also states that the Government should implement the following mechanisms to promote the upscaling of renewable energy use:[13]

- Incentives on renewable energy technologies such as tax waivers to minimize costs;
- Capacity building in renewable energy technologies;
- Awareness campaigns;
- Development of national renewable energy strategy (which will follow after the NEP review);
- Development of feed-in tariffs and a power purchase agreements framework.

Legislation on small hydropower

The Energy Regulation Act (No. 20 of 2004) regulates the energy sector to include renewable energy projects and generation. Additionally, several other pieces of legislation relate to the development and operation of SHP in Malawi. The Water Resources Act 1969 (Act No. 15) governs the use and conservation of water resources within the country. The Waterworks Act 1995 (No. 17 of 1995) empowers the Minister to declare water areas and establishes for each water-area a Water Board; the Water Board has the authority to approve any installations or utilization of water resources.[14]

Barriers to small hydropower development

The main challenges to developing SHP in Malawi are the absence of data, feasibility studies and technology as well as the high cost of infrastructure. The Government also lacks financial mechanisms, policies and regulatory framework which are needed to promote the SHP sector.[15] These conditions have also resulted in a lack of private investors. However, the Government is hoping to overcome these challenges by developing a conducive environment for private investors and conducting feasibility studies for independent power producers. SHP development is also being affected by environmental degradation due to deforestation for firewood and charcoal and farming activities upstream and near the river banks leading to rivers drying up.

1.1.6 Mauritius

Khalil Elahee and Vassish Dassagne, University of Mauritius

Key facts

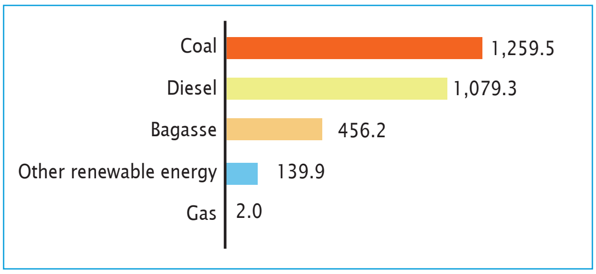
Population	1,219,659[1]
Area	1,865 km[2]
Climate	A mild, tropical, maritime climate with little variation between two seasons, summer and winter. Summer is warm and humid lasting from November to April with an average temperature of 24.7°C. Winter is comparatively cooler and dryer with an average temperature of 20.4°C.[2]
Topography	The island is mostly a volcanic formation surrounded by coral reefs. A coastal plain rises sharply to a central plateau between 275 and 580 m high, with surrounding mountain chains and some isolated peaks. The highest point, Piton de la Petite Riviere Noire, is 828 m above sea level.[3]
Rain pattern	Annual precipitation has a total volume of approximately 3,821 million m^3. Average annual rainfall is 2,010 mm. Although there is no marked rainy season, most of the rainfall occurs in the summer months. Average summer rainfall is 1,344 mm or 67 per cent of the country's total rainfall. Average winter rainfall is 666 mm.[4]
General dissipation of rivers and other water sources	There are 20 main rivers in Mauritius. The longest is the Grand River South East (Grande Rivière Sud-Est) which is roughly 27.67 km long and is located in the central-eastern region. The other main rivers include Black River (Rivière Noire), Post River (Rivière du Poste), Grand River North West and Rempert River. Several waterfalls exist, with the highest being the Tamarin Falls in the west at 293 m.[3] There are also 10 man-made reservoirs on the island.[5]

Electricity sector overview

In 2014, the total installed capacity in Mauritius was 764.7 MW with a total effective capacity of 687.3 MW. The peak power demand in 2014 reached 446.2 MW with electricity generation reaching 2,937 GWh in the same year. Sources of electricity in Mauritius include coal, diesel and fuel oil, kerosene, hydropower, bagasse, photovoltaic, wind and landfill gas. Coal and diesel together contribute almost 80 per cent of the country's electricity generation. This is followed by bagasse which accounts for roughly 15 per cent (Figure 1).[4]

FIGURE 1

Electricity generation in Mauritius by source (GWh)

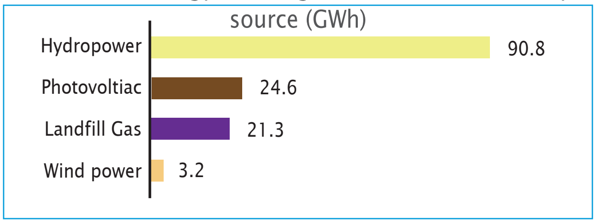


Source: Central Statistical Office[4]

Renewable resources generated 596 GWh in 2014 and represented 20 per cent of the total electricity production. Bagasse accounted for over 75 per cent of this. The remaining sources accounted for just 4.7 per cent of the total electricity production. Of this 4.7 per cent, hydropower accounted for 65 per cent, photovoltaic and landfill gas provided 18 per cent and 15 per cent respectively and wind power provided just a small fraction (Figure 2).[4]

FIGURE 2

Renewable energy annual generation in Mauritius by source (GWh)



Source: Central Statistical Office[4]

The electrification rate is high at 99.4 per cent with 100 per cent of urban population receiving electricity compared to 99 per cent of the rural population. This follows a 37-year rural electrification programme (REP) that ended in 1981 after all the rural villages had been electrified.

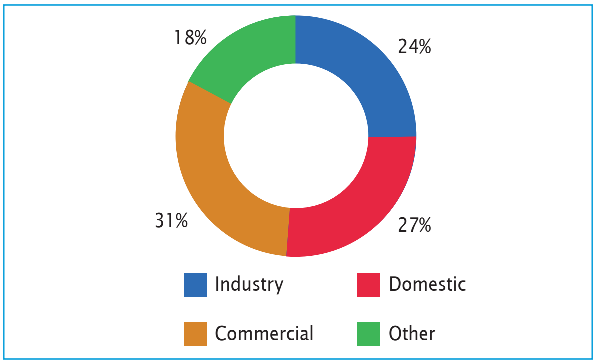
Residential and commercial users were the two biggest consumers of electricity in 2014, consuming 806.2 MWh and 894.1 GWh respectively with industry consuming 715.1 GWh (Figure 3).[4]

In 2013, commercial users consumed 894.1 GWh

(35.7 per cent) of the total demand while residential users consumed 806.2 GWh (32.8 per cent). The Central Electricity Board estimates that commercial demand will increase to 1,300 GWh by 2022 due to industrialization and diversification of the economy. Residential demand is estimated to increase to 900 GWh by 2022.[6]

FIGURE 3

Electricity consumption in Mauritius (%)



Source: Central Statistical Office[4]

The Central Electricity Board (CEB), a parastatal body wholly owned by the Government and established in 1952, has responsibility under the Central Electricity Board Act of 25 January 1964 to "prepare and carry out development schemes with the general object of promoting, coordinating and improving the generation, transmission, distribution and sale of electricity" in Mauritius. The CEB accounts for 40 per cent of the power produced in the country with Independent Power Producers (IPPs) providing the remaining 60 per cent.[6] The Utility Regulatory Authority Act, which was introduced in 2005, has not yet been enforced. Once established, the resulting regulatory authority will have control over the operation of the electricity market including regulating third party access to the grid and playing a vital role in restructuring the sector.

The private sector has an important role to play in the development of electricity facilities, such as building new plants and production facilities for energy generation. For example, the IPPs provide for the full and efficient use of bagasse as a local, renewable biomass fuel for energy generation.

Small power producers can either export their excess electricity on the CEB grid or sell it directly to a third party. The law has been amended to facilitate this process, and, though concrete measures have yet to be implemented, government incentives such as the removal of a standby charge for renewable energy have been introduced.

A study commissioned by the CEB, and financed by the United Nations Development Programme (UNDP) and the World Bank, recommends upgrading the existing CEB power plants to enhance integration by up to 110 MW for renewable energy as well as the use of large battery storage to increase penetration up to 150 MW.

There are 22 types of tariffs in the CEB's tariff schedule ranging from 3.16 Mauritian Rupees/kWh (US$0.09) for low-end residential consumers to a flat rate of 5.40 Mauritian Rupees/kWh (US$0.12) for high-end industrial consumers.[7] Special consideration is given to the social dimension of electricity consumption by households. For example, the CEB has in place a social tariff (Tariff 110A) intended for customers in difficult financial situations and whose monthly consumption does not exceed 75 kWh. Under this scheme, customers whose monthly consumption does not exceed 75 kWh benefit from concessionary electricity rates.

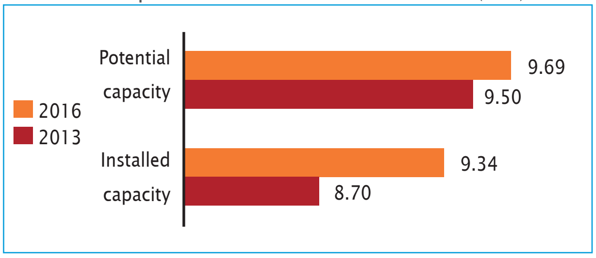
Existing electricity tariffs are not cost-reflective and consist of a substantial amount of cross-subsidization. There are currently difficulties in restructuring tariffs as this can seriously affect customers' budgets (especially for subsidized tariffs). Thus any restructuring of tariffs which are not cost reflective must take into consideration the social dimension of the island. Additionally, changes in the network, where customers are now also producing electricity, requires proper planning and design.

Small hydropower sector overview and potential

There is no official definition of SHP in Mauritius so this report assumes the 10 MW definition held by ICSHP. Installed capacity of small hydropower (SHP) in Mauritius is 9.34 MW and potential capacity is at least 9.69 MW indicating that more than 93 per cent has been developed.[6] Since the publication of the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, the installed capacity has increased by approximately 7 per cent and the estimated potential by 2 per cent (Figure 4).[8]

FIGURE 4

SHP capacities 2013-2016 in Mauritius (MW)



Sources: CEB,[6] *WSHPDR 2013*[8]

Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

There are seven existing SHP plants owned by the CEB with a total installed capacity of 9.04 MW (though the effective capacity is just 8.65 MW) providing 18.2 GWh annually. Two SHP plants have been commissioned recently. The La Nicoliere Feeder Canal Hydro was commissioned in 2010 and the Midlands Dam Hydro in March 2013. The remaining plants have a mean age of about 50 years with the oldest being the Reduit plant which became fully operational in 1906. Le Val and La Ferme were both refurbished in 2008 (Table 1).

TABLE 1

Operational SHP plants <10 MW in Mauritius

Name	Installed capacity (MW)	Average annual production (GWh)	Description
Le Val	4 MW	4 GWh	183 m head across Eau Bleue reservoir (4.1 million m^3 capacity). Commissioned in 1961, refurbished in 2008.
Cascade Cecille	1 MW	3.5 GWh	76 m head run of the river across Riviere des Anguilles Rivers. Commissioned in 1963.
Reduit	1.2 MW	3 GWh	50 m head run-of-river across Terre Rouge and Cascade Rivers. Fully in operation since 1906 . upgraded in 1984.
La Ferme	1.2 MW	2 GWh	127 m head near La Ferme reservoir. Rebuilt in 1988, refurbished in 2008.
Magenta	0.94 MW	2 GWh	45 m head across a dam on canal near Tamarind, used for irrigation also. Commissioned in 1960.
Midlands	0.35 MW	2 GWh	Supplied by Midlands Dam (25.5 Mm capacity), 38.4 m head and 88 m penstock. Commissioned in march 2013.
La Nicoliere	0.35 MW	1.7 GWh	Across La Nicoliere reservoir feeder canal. Commissioned in 2010.
Riche en Eau	0.2 MW	0.12 GWh	Privately owned
Bois Cherie	0.1 MW	0.48 GWh	Privately owned

Source: Central Electricity Board[10]

Additionally there are also two private power stations, Riche en Eau (200 kW) and Bois Cherie (100 kW), which brings the total installed capacity for SHP to 9.34 MW. In total, SHP of less than 10 MW represents 20 per cent of the country's total hydropower production.

There are no existing studies to give an accurate figure of SHP potential in the country. Nonetheless, the CEB has commissioned a new station at Bagatelle Dam with a capacity of 350 kW. Once it is fully operational as expected in 2017, it will bring the total potential capacity up to at least 9.69 MW. Aside from this planned station, it is believed that all significant hydropower has already been developed. There remain, however, a number of opportunities for mini- and micro-hydropower plants that the Government is keen to develop. To achieve this objective and as part of the CEB Integrated Plan 2013-2022 (see below), the CEB initiated a feasibility study in 2014 to identify potential sites for the development of micro- and mini-hydropower projects. This study is yet to be completed.

The Government is also encouraging the set-up of mini-hydropower plants under the Small Scale Distributed Generation (SSDG) scheme although so far none has been commissioned.

Renewable energy policy

The long-term vision of the Mauritian Government is to reduce its dependency on imported energy carriers by increasing the use of renewable sources. According to the Long-Term Energy Strategy 2009-2025 the Government aims to increase the share of renewable energy production to 35 per cent by 2025.[9]

In 2008, the Mauritius Sustainable Island (Maurice Ile Durable) project was launched to provide grants for the promotion of clean energy. As part of this initiative, a tax on fossil fuels was imposed to subsidize renewable energy and sustainable development projects. The tax, imposed in 2008, was doubled in 2011 to 0.30 Mauritian Rupees (US$0.01) per kg of coal, liquid petroleum gas (LPG) and other petroleum products. A carbon tax was also imposed on vehicles from July 2011.

The Integrated Electricity Plan (IEP) 2013-2022 provides a 10-year plan of the energy sector in Mauritius. According to the IEP, tenders will be issued for renewable energy as per the following schedule: 10 MW solar in 2016, 20 MW wind in 2017, 10 MW solar in 2019, 20 MW wind in 2020 and 10 MW solar in 2022. Approximately 70 MW of solar and wind energy is currently in the planning stage.

In December 2010, the CEB, in collaboration with the Ministry of Energy and Public Utilities, launched the Small Scale Distribution Generation (SSDG) scheme, through which small Independent Power Producers (IPPs) are given the opportunity to produce their own electricity from renewable sources (photovoltaic, wind or hydro) and export any surplus to the grid. The scheme allows small IPPs to generate electricity on a small scale with a maximum individual capacity of 50 kW. Additionally, the Medium Scale Distributed Generators (MSDG) scheme gives special feed-in tariffs (FITs) for capacities above 50 kW but lower than 4 MW. As part of these schemes, a new grid code to ensure a safe two-way flow of electricity and attractive FITs was drafted.

The FITs established for the first 15 years of production are shown in Table 2. SSDG owners must consume one third of the energy produced otherwise the FIT for the following year will be reduced by 15 per cent.[9]

The initial target of 2 MW installed capacity, which was reached in May 2011, consist of 1 MW for residential consumption (195 applicants) and 1 MW for commercial and industrial consumption (76 applicants). A second phase of the SSDG was launched in December 2011 for a total capacity of 1 MW.[10] According to the CEB, this target was also achieved and in 2012 an additional 2 MW was allocated under the SSDG scheme for educational, charitable and religious institutions and applications are still being processed.

From September to December 2011, the energy exported to the CEB network amounted to 2,334 kWh. In 2012, this figure reached 193,000 kWh and rose to 1,197,516 kWh in 2013. One of the biggest reasons for the success of the SSDG scheme was the highly attractive FITs proposed by the CEB. This success, however. did not translate into SHP as no SHP sites have so far been built under the scheme.

In the 2014 national budget, new regulations were announced to liberalize the sale of electricity to third parties within well-defined developments. This measure enables the generation of electricity from renewable energy sources by private promoters for direct sales to third-party occupiers (including tenants).

In the 2015 national budget, the Government announced its intention to exceed its previous target of 35 per cent renewable energy. As a result, in March 2015, a new target of 50 per cent was confirmed by the Minister of Energy and Public Utilities.[12,13] The budget also announced the establishment of the Mauritius Renewable Energy Agency to promote the development of renewable energies. Additionally, investment in solar and other renewable energies will be eligible for financing as well as other incentives under the Small and Medium Enterprise Financing Scheme. A land conversion tax exemption for all renewable energy project promoters was also declared.

Despite the initiatives outlined above, challenges still remain for the development of renewable energy. The cost of importing fossil fuels for energy generation in Mauritius is significant. Renewable energy sources are not yet widely used and energy consumption in buildings and industry is often inefficient. The building sector alone accounts for about 78 per cent of total national carbon emissions. However, the cost of generation from renewable energy is comparatively higher (especially for solar and wind) than that of conventional sources of power generation. This is largely due to the initial investment cost and very low capacity utilization factor.

However, these costs may decrease as competition among suppliers of renewable technologies on the world market increases and new improved products with higher efficiencies are developed. Other fiscal incentives must also be introduced to counter the high cost of renewable energy production such as decreasing the tax on materials needed for construction as well as additional incentives similar to the SSDG scheme and taxation charges on pollution to make renewable sources more attractive.

Legislation on small hydropower

The Environment Protection Act (EPA) 2002 provides the legislative and administrative framework for the protection and preservation of the environment and, according to the CEB Integrated Plan 2013-2022, an Environment Impact Assessment (EIA) licence needs to be obtained for all mini- and micro-hydro plants.

Barriers to small hydropower development

Hydropower in Mauritius has been almost fully developed. However, there is potential for mini- and micro-hydropower plants and opportunities to improve storage capacity for industrial, agricultural and residential purposes. Opening the electricity market to independent producers has been successful in promoting production of electricity from renewable sources. Despite this, more financial incentives are required to further reduce the cost of all renewable energy sources including SHP.

Additionally, only 10 per cent of the country's total precipitation is effectively used with the remaining 90 per cent lost to evapotranspiration and runoff. With better water management, the shortage of water could

TABLE 2

Feed-in tariffs for renewable energy sources in Mauritius

	FIT tariffs (Indian rupees (US$)/kWh)		
Size	**Hydropower**	**Photovoltaic**	**Wind**
Micro (up to 2.5 kW)	15 (0.28)	25 (0.47)	20 (0.38)
Mini (2.5-10 kW)	15 (0.28)	20 (0.38)	25 (0.47)
Small (10-50 kW)	10 (0.19)	15 (0.28)	10 (0.19)

Source: Central Electricity Board[11]

be alleviated and hydro plants can be used effectively.[4] For example, in 2011, due to a water shortage in the country, water that otherwise would have been used by hydropower plants was diverted to other sectors. Thus, if the problem of water scarcity is improved, adequate water supply can be allocated to hydropower plants.[11] Furthermore, the efficient use and management of existing hydropower plants could help the CEB to meet its peak demand.

Climate change is also proving to be a major challenge for all renewable energies, especially for wind, solar and hydropower of all sizes with changes in the predictability of rain patterns adversely affecting generation.

General barriers include the following:

- Topography of the island is almost flat.
- Cost of constructing dams and hydro plants is high.
- Lack of proper infrastructure to access potential sites.
- Difficult to expand existing dams.
- Seasonal fluctuations affecting rainfall.
- Limited catchment areas.
- Inefficient management of water leading to competition with domestic use.
- Impact on environment for building hydropower plants (on residents as well as flora and fauna).
- High cost of equipment.

1.1.7 Mozambique

Claudio Moises Paulo and Esmenio Isabel Joao Macassa, Universidade Eduardo Mondlane; Domingos Mosquito Patricio, Direccao Nacional de Gestao de Recursos Hidricos; Nathan Stedman, International Center on Small Hydro Power

Key facts

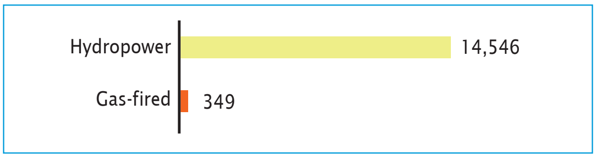
Population	27,216,276
Area	799,380 km^2
Climate	The weather along the coast of Mozambique is sunny and warm, although the southern areas are typically cooler than the north. The summer months (October to April) are rainy, humid and very hot. The winter months (April to September) are cooler and drier. Coastal temperatures during the day average between 24°C and 27°C and can rise up to 31°C.[17]
Topography	Mozambique is a topographically diverse nation. The Zambezi River divides the country into distinct northern and southern halves. The north has mountainous regions and plateaus, the Livingstone-Nyasa Highlands, the Shire (or Namuli) Highlands and the Angonia Highlands in the north-east. The western most regions are particularly mountainous. South of the Zambezi are the more fertile plains, most notably in the area surrounding the river.[17]
Rain pattern	Rainfall varies greatly between the regions and areas of the country. The north-eastern coast is the hottest and most humid in the country with average rainfall of 1,000 mm to over 2,000 mm. The annual average precipitation for the whole country is 1,032 mm and the rainy season lasts from October to April. Average rainfall ranges from 800 to 1,000 mm along the coast. The rainfall decreases inland reaching 400 mm at the border with South Africa and Zimbabwe.[17]
General dissipation of rivers and other water sources	Mozambique has 104 river basins that drain the western highlands to the Indian Ocean or to the Mozambique Channel in the east. The Zambezi basin is one of the largest river basins in Africa and the most important to Mozambique. It accounts for about 50 per cent of the surface water resources of the country and about 80 per cent of its hydropower potential with the Cahora Bassa dam. Water flow tends to fluctuate, owing to the rainy and dry seasons. The rivers overflow between January and March and slow in June and August. The two main lakes are Lake Niassa (Lake Malawi) and Lake Chirua (Lake Chilwa), both of which are shared with Malawi.[17]

Electricity sector overview

In Mozambique, the Ministry of Energy is responsible for policy-making and supervising the country's energy sector. The Conselho Nacional de Electricidade (CNELEC, National Electricity Coucil) is the regulatory authority for electricity. Electricidade de Moçambique (EDM, a state-owned utility) is tasked with generation, transportation and distribution of electricity throughout the country. The largest electricity producer is Hidroeléctrica Cahora Bassa (HCB), a state-owned independent power producer (IPP), which is responsible for the operation of the Cahora Bassa hydropower scheme (2,075 MW).[2,15]

FIGURE 1

Electricity generation in Mozambique (GWh)



Sources: IEA,[19] RECP [15]

The total installed capacity in Mozambique in 2014 was 2,475 MW with 2,275 MW of hydropower and 200 MW of fossil fuel capacity.[15] In 2014, electricity generation reached 14,895 GWh, with 14,546 GWh from hydropower and the remainder from gas-fired plants (Figure 1).[19]

The energy sector in Mozambique, which comprises all forms of primary and transformed energy sources, involves the following stakeholders:

- Electridade de Moçambique (EDM);
- Hidroeléctrica de Cahora Bassa (HCB);
- Companhia Eléctrica do Zambeze (CEZA);
- Redes Energéticas Mozambique Nacionais (REN) of Portugal;
- Mozambique Transmission Company (MOTRACO) which supplies alluminum smelters;
- Fundo Nacional de Energia (FUNAE) which involves mostly off-grid generation;
- Instituto Nacional do Petróleo (INP);
- Companhia Moçambicana de Hidrocarbonetos (CMH);
- Independent Power Producers (IPP).

The development of IPP participation is underway in the power generation sector. At present, the Temporary Power Generation Company (Aggreko) operates on a short-term contract, while Ressano Garcia Central Térmica (CTRG), Ncondezi, Moatize, Vale and others are in varying stages of progress with their respective plans to develop generation capacities.

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. Grid extensions to rural areas and intensification in urban areas enabled the connection of all provincial capitals in 2007 and 120 district capitals in 2014. This resulted in an increase in the electrification rate, from 7 per cent in 2004 to 13 per cent in 2013. By 2012, a total number of 1,024,000 new customers in all regions and provinces of the country were connected.[9]

However, the grid extension has not increased diversity in the energy mix and the country still has a high degree of reliance on a single energy source, namely, hydropower. Week-long blackouts due to natural disasters and operating failures have caused substantial losses to the national economy. In addition, Mozambique suffers from administrative, transmission and distribution losses totalling 27 per cent of power generated. This further exacerbate the country's increasingly acute energy shortage.[9]

The Government is currently undertaking projects to strengthen the transmission network, known as the backbone project, to increase transmission efficiency of electricity from the generation areas, namely Tete, to the load centres along the coast. The extensive new power transmission infrastructure spans more than 5,360 km with transmission capacity of about 5,500 MVA across the national territory. The improvements will also increase exports to South Africa and other neighbouring countries, in particular once several large new hydro projects are completed, namely Mphanda Nkuwa Hydropower (1,500 MW), HCB North Bank (1,245 MW) and a number of other initiatives such as Lupata (600 MW), Boroma (200 MW) and Lurio (120 MW).[14]

TABLE 1

Electricity tariffs in Mozambique (EUR (US$)/kWh)

Tariff	0-100 kWh	0-200 kWh	201-500 kWh	>500 kWh	Prepaid
Social tariff	0.028 (0.032)	—	—	—	0.028 (0.032)
Household	—	0.061 (0.069)	0.081 (0.092)	0.085 (0.096)	0.077 (0.087)
Flat rate	—	1.960 (2.216)	1.960 (2.216)	1.960 (2.216)	—

Source: RECP[15]

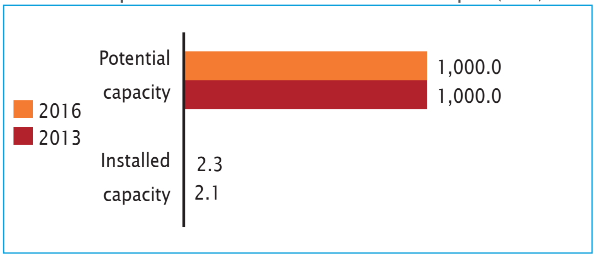
The rules and the prices used by the Electricidade de Mozambique (EDM) are set out in the Tariff System for the Sale of Electric Energy, in the Decree number 29/2003 of 23 July 2003. According to this Decree, the tariff system sets prices by taking into account the voltage, the tariff option and the period of energy supply. The legislation defines three kind of voltage (tension): low-voltage (1 kV), mid-voltage (1 kV-66 kV) and high voltage (from 66 kV).[3,15]

Small hydropower sector overview and potential

The country's greatest hydropower potential lies in the Zambezi River basin at sites such as Cahora Bassa North and Mphanda Nkuwa. So far, over 2,000 MW of generating capacity has been developed. Mozambique classifies small hydropower (SHP) as plants with an installed capacity up to 25 MW. However, for the purposes of this report, SHP is defined as 10 MW or less. Since 2013, the installed capacity has increased slightly while the potential capacity has remained unchanged (Figure 2). It should be noted that under the Mozambican definition, the Corumana Dam would be included, bringing installed capacity of SHP up to 18.3 MW.[8,13]

FIGURE 2

SHP capacities 2013-2016 in Mozambique (MW)



Sources: IJHD,[8] *WSHPDR 2013*,[13] Wim Jonker Klunne,[11] Hydro4Africa[12]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

Other than the 16 MW Corumana plant, there are several SHP installations, including Lichinga (0.75 MW), Cuamba (1.1 MW) and numerous mini- and micro-plants (Table 2). In terms of rural electrification, SHP plants are a promising solution for inclusive and sustainable development as they are able to provide affordable and efficient electricity to isolated and remote locations.[8,12]

Renewable energy policy

Mozambique is a country rich in natural and renewable energy (RE) resources. In addition to its vast hydropower potential, there are several sources of renewable energy that could change the energy mix in the country: a large portion of the territory is suitable for efficient solar energy production; biomass is plentiful, in particular agriculture waste such as rice husks in Quelimane; wind potential is greatest in the south; and promising geothermal sources in the north. All these could be utilized to supply the ever increasing electricity demand.[10]

TABLE 2

Micro, mini and small hydro in Mozambique (<25 MW)

Site name	kW	Site name	kW	Site name	kW
Changuara	6.0	Chimukono	26.0	Naquarai	22.0
Chimedza	10.0	Chitofu	30.0	Cuamba	1,090.0
Chirodzo	6.0	Chitunga	30.0	Lichinga	750.0
Chiwijo	10.0	Dera	12.0	Corumana	16,000.0
Ganhira	5.0	Ganhira	16.0		
Mavonde	10.0	Honde	65.0	Majaua*	530.0
Nhamuquarara (Chaningwa)	5.0	Jimy	18.0	Rotanda*	620.0
Nhamuquarara (Mucheca)	5.0	Lino	18.0	Chiurairue*	23.1
Nhamuquarara (Mvundula)	5.0	Mangunda	26.0	—	—
Nhamuquarara (Tiga Arone)	10.0	Mudododo	16.0	—	—
Reserva Chim	5.0	Mussapa	20.0	—	—
Tendayi Zvemapowa	9.6	Ndiriri	26.0	—	—
Vista Alegre	8.0	Nerufunde	20.0	—	—
Nhamuquarara Pedro Tanganji	26.0	Tendayi	14.6	—	—
Chihururu	22.2	Ngwarai	25.0	—	—

Sources: Wim Jonker Klunne,[11] Hydro4Africa[12]
Note: An asterisk (*) indicates under development as of data collection period (2015).

The legal framework for foreign investment and renewable energy is currently undergoing review. The applicable laws 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 15/2011 and Decree 12/2012).[9]

The Government's renewable energy policies have helped spur development within the energy sector, which are by and large issued from the Direcção Nacional de Energias Novas e Renováveis (National Directorate of New and Renewable Energies). The target of increasing the electrification rate to 50 per cent by 2024, and objectives established within the SE4ALL framework, could potentially double the amount of renewable energy utilized in the country.

In conjunction with the Government's Poverty Reduction Strategy, the National Strategy for Renewable Energy and the Green Economy Action Plan aim to increase private sector competitiveness as well as develop or improve current infrastructure. In line with these policies, the Sustainable Energy Fund for Africa (SEFA) approved a US$740,000 grant for technical assistance in enabling private investments in the RE sector.[10]

Legislation on small hydropower

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.[19] 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 in remote areas, extension of the national electricity grid production and transmission capacity, as well as economic development in general.[18]

Barriers to small hydropower development

The consumption of energy resources has a price, whether in terms of monetary costs or environmental degradation. For that reason, there is a need to consume energy in the most efficient way possible. It is a challenge to determine the level of duration for an adequate support in order to ensure and built a safe and sustainable energy system. The Policy for the Development of Renewable Energies and its Strategy, and the regulatory instruments show the commitment of the Government in this field.

Mozambique has hydropower potential of approximately 12,500 MW but only 20 per cent of it has been developed. There are more than 100 hydropower sites to be studied for potential development of hydropower plants. Although there is some experience in the installation of SHP plants, mainly in Manica, Tete and Niassa, there is a need to do the following in order to overcome the challenges of the energy sector:

- Consolidation of the legal, political and strategic framework;
- Creation of databases regarding renewable energy resources;
- Local development of technologies;
- Establishment of the market.

Joint actions, such as the following, must be developed in order to overcome these challenges:

- Implement policies and a strategic framework in order to promote the development of renewable energies.
- Establish a friendly environment for banks, private investors and the civil society in the study, promotion and renewable energy implementation.
- Ensure a database of renewable energy potential in order to attract private investors.
- Establish a platform in order to promote technological development.
- Create integrated programmes of investigation and development within the private sector and the civil society.

1.1.8 Réunion

Sandra Vatel, Électricité de France

Key facts

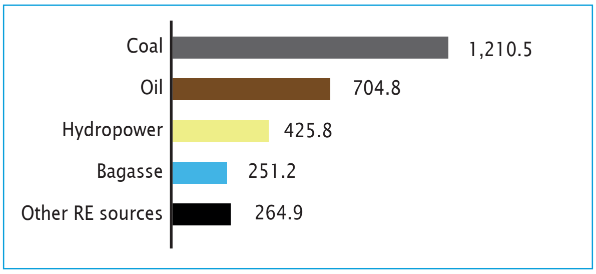
Population	833,944[1]
Area	2,504 km²
Climate	The weather is tropical and humid with the warm and humid season stretching from November to April and the drier season from May to October.[3] The summer from December to March has an average temperature of 26°C on the coast. Winter is from April to November and has an average temperature of 20°C on the coast. Temperatures drop significantly in the interior (at higher altitudes).[8]
Topography	Réunion island has mountain peaks in the interior. It is the result of volcanic activity and the island has two distinct volcanoes: the Piton des Neiges (Snow Peak) which is now extinct and the younger and more active Piton de la Fournaise (Furnace Peak). The Piton des Neiges is the highest point on the island and in the Indian Ocean at 3,072 m above sea level.[8]
Rain pattern	The summer months (from December to March) are also the wettest, with an average of 225 mm of rainfall in February. The driest month is October, with an average of 42 mm.[9]
General dissipation of rivers and other water sources	A large number of rivers flow through the island of Réunion; the Rivière des Marsouins runs abundantly all year round. Other notable rivers are la Rivière des Marsouins, le Bras Sainte Suzanne, Grand-Bois and the Salazie and Mafate Rivers.[8]

Electricity sector overview

Réunion island is an overseas department and an administrative region of France. Réunion aims to reach 100 per cent of electricity production via renewable energy sources by 2030.[3] Electricity is provided by Électricité de France (EDF).

FIGURE 1

Electricity generation in Réunion by source (GWh)



Source: Energies Réunion (2014)[5]

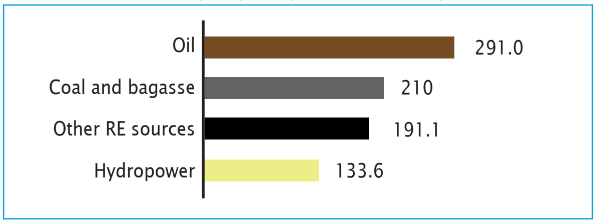
The total electricity production in 2013 was 2,813 GWh, from a mix of thermal and renewable sources, with coal being the predominant energy source (Figure 1). It is worth noting that the electricity production in 1982 relied solely on hydropower.[4] Data in 2014 showed that generated electricity increased to 2,857 GWh, of which 67 per cent was from fossil fuels (petroleum and coal) and 33 per cent from renewable energy.[5] The average growth of electricity production in Réunion had decreased from 4.4 per cent per year between 2000 and 2010 to 1.4 per cent per year from 2010 to 2014 as a result of a demand management programme authorized in 2000 and an increased use of costly fossil fuel.[5]

In 2014, 941.9 GWh were produced by renewable sources (–11.3 per cent compared to 2013) of which 426 GWh was produced by hydropower (–23.5 per cent compared to 2013). The annual generation varies according to rainfall and accumulation.

Réunion has invested in a diverse range of renewable energy sources. The most utilized source was hydropower until 2011 (it was one of the first renewable sources used on the island). But since 2012, photovoltaic is more developed (173 MW in 2014) than hydropower (134 MW in 2014).[5]

FIGURE 2

Installed electricity capacity in Réunion by source (MW)



Source: Energies Réunion (2014)[5]

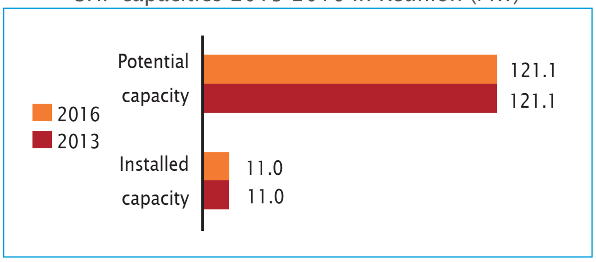
Réunion has recently embarked on a major project known as Sea Water (Sea Water Air Conditioning) designed to reduce energy bills and the island's carbon footprint. The system involves pumping water from the Indian Ocean from a depth of 1,100 m off the island's coast and transporting it along a 6 km high density polyethylene offshore pipeline built to resist waves.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Réunion is in accordance with French legislation. Therefore, plants up to 10 MW are considered SHP plants. The total SHP installed capacity in Réunion is 11 MW. The total SHP potential in the island is 121.10 MW.

Within the 121.10 MW of hydropower potential, 59.10 MW are difficult to be realized, 50.53 MW are under strict conditions and 11.47 have no restrictions.[7]

FIGURE 3
SHP capacities 2013-2016 in Réunion (MW)



Source: Energies Réunion,[5] *WSHPDR 2013*[10]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

Hydropower is produced at Rivière de l'Est (80 MW), Takamaka I (17 MW) and II (26 MW), Bras de la Plaine (4.6 MW) and Langevin (3.6 MW), Bras des Lianes (2.2 MW) power plants as well as Picocentrale RT4 (0.2 MW), for a combined capacity of 134 MW.[5] Though the large and SHP potential has been mostly tapped, there is still a number of potential sites where micro-hydropower projects can be installed.

A technical report from 2008 indicated that there were four run-of-river type plants with a total installed capacity of 10.5 MW (62.65 GWh) and three stations with a total capacity of 106.5 MW (550,000 GWh). There is no pumped storage technology on the island.[7]

Taking environmental issues into consideration, there are several more categories for the realization of hydropower potential, such as irrigation infrastructure.

Renewable energy policy

In 2000, the Regional Council of Réunion implemented the Regional Plan for Renewable Energies and Rational Energy Use (PRERURE) that served as a precursor for the Grenelle Environment on Réunion – Succeeding through Innovation (GERRI) project which has the objective to integrate environmental innovation, mobility, energy and its uses, urban planning, construction and tourism into society. The Overseas Territories Orientation Law, in place since December 2000, is the platform pushing for the decentralization of the French overseas departments and the implementation of PRERURE. It is important to take into consideration the support provided by the European Union (EU). This includes direct support in the form of research funding via tenders and indirect support by the means of helping the regional authorities to enable the application of EU policy in overseas departments.[5] A goal of self-sufficiency by 2030 under the GERRI project was proposed in light of the estimated population stabilization of one million people by 2030.[5] The renewable energy sources available on the island are wind, solar, geothermal, wave, tidal, hydro and energy from biomass, landfill gas, gas stations, wastewater treatment and biogas.

Act No. 2005-781 of 13 July 2005 lays down the guidelines of the programme for energy policies and renewable energy in Article 29.[6] In addition, incentive mechanisms are also in place to encourage the development of renewable sources, including tax exemption, direct subsidies and feed-in tariffs (FITs) controlled by EDF.[5] Private plants, however, have a tax credit rate that varies between 25 per cent and 50 per cent based on the technology of the project.

Barriers to small hydropower development

The main disadvantage to SHP development is the cost of technology which increases due to the island's insularity and the related cost of transportation and taxes. As a result, higher capital costs hinder contractors' willingness to undergo financial risk and investment in Réunion.[5] Based on the country's geographic characteristics, contractors are also faced with the risk of climatic variation and destruction coupled with volcanic activity which increases the risk factor for investors.

Environmental impact assessments are stringent and often represent a difficult barrier to SHP development due to the classification of Réunion as a World Heritage Site, under the United Nations Educational, Scientific and Cultural Organization (UNESCO). This has a further domino effect on the price of land per square metre that over the last 10 years has experienced a significant increase, amplifying initial investment expenditures.[5] Coordination between departments and authorities, both local and overseas, are ineffectual, thus prolonging the implementation process for project owners. Coupled with a lack of local technical support, this creates another disincentive for potential investors. The final major barrier to SHP development is the lack of information and often contradictory sources with different and misleading data, further slowing down the process of development. Currently, the Réunion Regional Energy Agency (ARER) is in the process of compiling renewable energy technology information to provide a one-stop data shop for potential investors. In the near future, this could decrease the initial research stage of most projects and encourage contractors to establish projects in Réunion.

1.1.9 Rwanda

Fredrick Kazungu, Carine Mukashyaka, Philbert Tuyisenge and Papias Karanganwa, Rwanda Electricity Group

Key facts

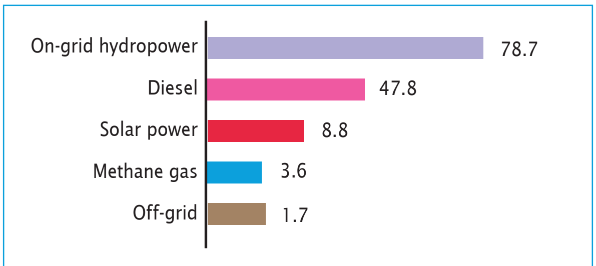
Population	12,708,786[1]
Area	26,338 km^2
Climate	Rwanda has a temperate tropical highland climate, with lower temperatures than are typical for equatorial countries due to its high elevation. The capital city, Kigali, situated in the centre of the country, has a typical daily temperature range between 12°C and 27°C, with little variation throughout the year. A long rainy season lasts from February to May and a short one from November through December.[2]
Topography	Rwanda is characterized by a topography which gradually rises from east to west. In the east, there is an average altitude of 1,250 m above sea level increasing to altitudes ranging between 2,000 and 3,000 m in the west. The main features are the Virunga volcano range in the north-west which is home to the country's highest point, Mount Karisimbi, at 4,507 m and the Congo-Nile Ridge stretching from south-west to north-west and culminating at 2,918 m above sea level.[3]
Rain pattern	The general climatic pattern reflects two rainy seasons and two dry seasons during the year. The average annual rainfall is 1,200 mm. However, it varies from region to region. In the eastern plateau and lowlands of the west, the average annual rainfall is 700 mm to 1,400 mm; in the central plateau, it is 1,200 mm to 1,400 mm; and in the high altitude region in the west, it is 1,300 mm to 2,000 mm. The rainfall regime strongly influences the hydrological regime. There are floods during the rainy season, which ordinarily is from March to May and they subside during the long dry season from June to September.[4]
General dissipation of rivers and other water sources	Rwanda is a landlocked country located within the Great Lakes region. The Congo Nile Ridge divides the country's waters into two principle basins, the Congo basin to the west constituting 67 per cent of the land area and the Nile Basin in the east constituting 33 per cent of the land area. The largest lake is Lake Kivu on the western border with the Democratic Republic of the Congo.[3]

Electricity sector overview

As of 23 December 2014, the installed capacity was 140.58 MW of which approximately 50.4 per cent came from on-grid hydropower plants, 30.6 per cent from diesel power plants and 9.9 per cent from imports. The remainder came from solar power, methane gas and off-grid plants (Figure 1), as well as 15.5 MW imported to meet demand.[5]

FIGURE 1

Installed electricity capacity in Rwanda by source (MW)



Source: Rwanda Energy Group[5]

The economy of Rwanda has been steadily growing at an average rate of 8.5 per cent. The Government plans to increase this to 11.5 per cent by 2020. In order for this target to be met, the energy sector needs to be improved through access to affordable electricity from modern sources.[6] Rwanda has one of the lowest energy consumption rates per capita in the world. Electricity accounts for approximately 4 per cent of primary energy sources with biomass contributing approximately 85 per cent.[6] Although the Government has increased electricity access by 180 per cent between 2008 and 2015, currently only 26 per cent of households, and less than 2 per cent of the rural population, are connected to the grid. The Government has set a target to increase the national electrification rate to 70 per cent by 2017 as well as to provide 100 per cent electrification of schools, health facilities and sector offices, either through connection to the grid or through reliable off-grid systems.[7]

Current projections for demand range between 250 MW and 470 MW, requiring an installed capacity of between

300 MW and 564 MW (with an estimated 20 per cent reserve margin).[8] However, the country is in the midst of a rapid expansion of its electrical grid and many new plants are proposed or under construction. The current target is to have an installed capacity of 563 MW by 2017 and may look to import up to an additional 450 MW from neighbouring countries.

The Government is prioritizing developing different generation sources to reduce perceived delivery risks and lay the groundwork for more private sector participation.9 In particular, the private sector is seen as helping to supply rural households by means of decentralized technologies such as solar lighting and village grids.[7] The installed capacity in 2017 is expected to comprise 340 MW of hydropower, 310 MW of geothermal power, 300 MW of methane-based power, 200 MW of peat-based power and 30 MW of diesel thermal plants.[10]

Rwanda has approximately 383.6 km of 110 kV high-voltage (HV) transmission lines and approximately 4,900 km of medium-voltage (MV, 30 kV, 15 kV and 6.6 kV) and low-voltage (LV, 380 V and 220 V) lines. The electric network is interconnected with the networks of Burundi, the Democratic Republic of the Congo (DRC) and Uganda. There presently is no inter-linkage with Tanzania. Power flows between Rwanda, Burundi and the DRC are managed by the International Society for Electricity in the Great Lakes Region (SINELAC). According to the Electricity Development Strategy for 2011-2017, Rwanda intends to extend its grid by 2,100 km (700 km of HV lines and 1,400 km of MV lines).[10] In addition to 110 kV lines, 220 kV interconnection lines are planned to connect power from planned new generation plants and meet the expected demand in the future. Construction of 400 kV lines is also under consideration within the framework of the interstate network development. There is ongoing construction of 220 kV lines, with some at the completion stages, for a number of transmission interlinkages including the 220 kV Kibuye-Kigali line, the 220 kV Kigoma–Rwegura (Burundi) and Birembo–Mbarara (Uganda) lines, and the 220 kV Rusomo– Birembo line.

The country’s principle legislation for the electricity sector, 2011 Electricity Law, governs the activities of electric power production, transmission, distribution and trading both within and outside the national territory of Rwanda. The law outlines the liberalization and regulation of the electricity sector, the development of power supply for all population categories and for all the country’s economic and social development sectors, the creation of economic conditions enabling electric power sector investments and respect for the conditions of fair and loyal competition and for rights of users and operators.

The Ministry of Infrastructure (MININFRA) is responsible for the overall coordination of activities in the energy sector and for the strategies, planning and monitoring of different programmes. MINIFRA also plays an important role in attracting private sector investment and coordinating support of development partners. Following reforms in 2013, the Rwanda Energy Group (REG) took over the energy operations formerly under the Energy Water and Sanitation Authority (EWSA). REG is split into two subsidiaries, the Energy Utility Corporation responsible for generation, transmission and distribution networks and sale of electricity while the Energy Development Corporation is in charge of new generation, transmission and electricity access development projects.

The role of the private sector has been limited in the past but the Government is currently encouraging electricity production through public private partnerships as well as in the hydropower sector to support management and construction. The Government has been supporting private investment in the sector through the following initiatives:

- The Government provides transmission access to all power projects at its own cost.
- Transmission line and road access to eligible projects.
- Provision of road access, and all infrastructures needed to develop projects.
- Generous fiscal and non-fiscal incentives including tax exemptions on power equipment.
- The Government acquires land for power projects at its cost or compensates private developers for land acquisition.
- Direct operating cost support by paying for fuel imports/equipment rental or exempting import tax.
- Capital Expenditure support by seeking external funds as well as funds allocation from budget.

Other indirect subsidies such as feed-in tariffs (FIT) for eligible generation technologies is being considered and consultant studies are being reviewed to determine appropriate tariff levels, especially for small hydropower (SHP) and other renewable energy sources.

The Rwanda Utilities Regulatory Authority (RURA) is the industry regulator responsible for setting and approving electricity tariffs, in consultation with the Ministry. Other key functions of RURA include the following:

- Conducting all technical regulatory activities for the power production, transmission and distribution sectors;
- Issuing permits and licences to firms that satisfy licensing requirements;
- Monitoring, evaluating and ensuring the quality of the technical services provided by the electric utility;
- Ensure both compliance to the adopted standards and a fair competition between electricity operators;
- Promote the utilization of renewable electrical energy resources in rural areas.

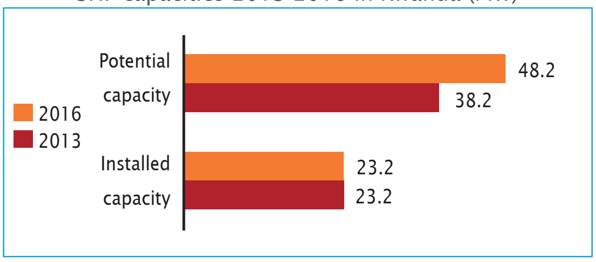
Rwanda has some of the highest electricity tariffs in the region which is compounded by its low purchasing power. The World Bank estimated annual per capita income at US$620 in 2012. The current electricity tariff is 182 Rwandan Francs (US$0.364)/kWh (excluding VAT) for small, low voltage consumers and 132 Rwandan Francs (US$0.264) kWh for large commercial and industrial medium voltage consumers (excluding VAT). A consultant study estimates that the tariff for residential and smaller non-residential customers is below the marginal cost of supply to residential customers, whereas the current industrial tariff is above the marginal cost of supply. The cost of supply is expected to be reduced by 2017 with electricity production shifting from expensive diesel-fuelled plants to cheaper hydropower and other generation options. The Electricity Law empowers RURA to set and approve electricity tariffs, in consultation with the Ministry and pursuant to laws and regulations in force. The Law also allows for cost-based tariffs to ensure adequate return on investments made by licence holders and for performance-based pricing and benchmarking.

Small hydropower sector overview and potential

SHP plants in Rwanda are defined as plants with an installed capacity up to 5 MW. Current installed capacity is 23.2 MW with a total potential of 48.2 MW, indicating that some 48 per cent has been developed.[11] In comparison to data from the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, the installed capacity remains the same. However, the potential has increased by approximately 26 per cent (Figure 2).[12]

FIGURE 2

SHP capacities 2013-2016 in Rwanda (MW)



Sources: Various[11,12,14]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

Current installed SHP capacity represents approximately 30 per cent of the county's total hydropower capacity. Table 1 gives details of 22 of the country's operational plants, the majority of which are privately owned. On 27 August 2015, the Ministry of Infrastructure announced it had leased 22 SHP projects located in the northern and western provinces to private investors to spur the country's hydroelectric energy programme. According to energy experts at the Ministry, the plants would add approximately 24.6 MW of hydroelectric energy to the national grid.[13]

The most significant resource assessment conducted to date is the Rwandan Hydropower Atlas. This was conducted in 2010 and it found that the majority of potentially feasible sites would be rated between 50 kW and 1 MW in capacity. The study estimated a potential capacity of 96 MW from micro-hydro projects alone. Feasibility studies have been completed or are under way for a number of sites, representing at least 32 MW of technically viable new capacity. In addition, over 192 sites have been identified for pico-hydropower plants with capacities below 50 kW. An ongoing comprehensive assessment of hydropower resources on the Akanyaru River basin, located on the border between Rwanda and Burundi, adopts this approach. These resources can be developed in cascade form, with 11 domestic sites and 3 shared sites recommended for further feasibility analysis. Based on preliminary estimates, these projects could potentially augment the country's total installed capacity by over 25 MW.

The Rwandan Government has integrated private-sector development into its policies for expanding electricity supply, and is planning to privatize all publicly-funded micro-hydropower plants while private small and medium-sized businesses are increasingly taking the lead in negotiations with the national energy provider and government agencies. To boost the private-sector participation in the hydropower energy programme, several Initiatives including the Private Sector Participation in Micro Hydro Power project, the Energy Small and Medium Enterprise (ESME) Trust Fund and the National Climate change and Environmental Fund (FONERWA) have been developed.

The Private Sector Participation (PSP) Hydro Project utilizes Public-Private Partnerships (PPP) to enable small and medium-sized businesses to install and operate sustainable micro-hydropower plants. PSP Hydro identifies and supports private firms throughout the project cycle with consulting services, training and limited co-financing. The first three privately-owned micro-hydropower plants in Rwanda, with respective capacities of 96 kW, 500 kW and 438 kW, have been connected to the national electricity grid, providing electricity to more than 20,000 people. The project developers are either Rwandan companies or joint ventures between Rwandan and international companies. Two additional micro-hydropower plants are currently under development, and other companies are now starting to develop projects without support from the PSP Hydro Project.[7]

As a result of the PPP approach, 75 per cent of the investment costs were raised from private capital through equity and commercial bank loans. Rwandan banks are financing private energy projects on a commercial basis for the first time and international investors have started investing in companies supported by PSP Hydro. Policy dialogue between the Government and private sector companies supported by the PSP Hydro project has led to the establishment of a solid investment framework. PSP Hydro has also supported the adoption of feed-in tariffs for micro-hydropower and the establishment of several regulations, including environmental standards and licensing procedures. When this project started in 2006, Rwanda had no private hydropower capacity. Since then, with PSP Hydro's support, the sector has developed

TABLE 1

Operational SHP plants in Rwanda

Name	Installed capacity (MW)	Available capacity (MW)	Ownership	Year of operation
Giciye	4.00	3.00	Private	2014
Mukungwa 2	2.50	2.50	Private	2013
Rugezi	2.20	2.20	Private	2011
Keya	2.20	1.00	Private	2011
Rukarara 2	2.20	2.20	Private	2013
Gihira	1.80	1.60	Private	1984
Gisenyi	1.20	0.60	Private	1957
Nkora	0.68	0.25	Private	2011
Mazimeru	0.50	0.00	Private	2012
Nyirabuhombohombo	0.50	0.00	Private	2013
Nshili1	0.40	0.00	Public	2012
Musarara	0.40	0.40	Private	2013
Cyimbili	0.30	2.50	Private	2011
Mutobo	0.20	0.20	Private	2009
Agatobwe	0.20	0.20	Private	2010
Janja	0.20	0.20	Private	2012
Nyabahanga	0.20	0.20	Public	2012
Gashashi	0.20	0.20	Private	2013
N/A	0.20	0.20	Private	2011
Murunda	0.10	0.10	Private	2010
Nyamyotsi I	0.10	0.10	Private	2007
Nyamyotsi II	0.10	0.10	Private	2011
Total	**20.38**	**17.75**		

Source: Rwanda Utilities Regulatory Authority[14]

to a point where over 20 companies are now working to provide Rwanda with the electricity it needs.

The Energy Small and Medium Enterprises (ESME) Trust Fund is a facility that was set up by the Russian Federation in 2009 providing US$30 million in the form of a grant facility to support small and medium energy enterprises in sub-Saharan Africa. Rwanda is one of the countries selected for support under the ESME Trust Fund with a total financing of US$3.5 million. The fund is provided through the World Bank and managed by the Sustainable Energy Development Project (SEDP) under REG. The ESME fund managed by SEDP is earmarked to support capacity building to ensure quality and competitiveness of private local investors in micro-hydropower projects. This will be done through support to business training opportunities and technical assistance to the investors in question.

The National Climate change and Environmental Fund (FONERWA) is a facility that was introduced by the Government to facilitate the financing of environment and climate change projects. This facility is available to both public and private developers through in-kind support for proposal development, performance based grants and low interest rate loans guarantees.

Renewable energy policy

The Electricity Development Strategy 2011-2017 outlines specific policies relating to renewable energy. In particular, the following targets have been set:

- Hydropower generation to be increased to approximately 333 MW.
- Geothermal power plants with capacity of 310 MW are to be developed.
- 5 MW is to be generated from other renewable energy sources (solar PV, micro-hydropower or wind) and distributed to local communities beyond the national electricity grid.
- Explore the possibility of developing all relevant projects as Clean Development Mechanism (CDM) projects right from the planning phase in order to promote emission reductions.
- Emphasise energy efficiency measures such as the reduction of technical and commercial losses on the national grid, distribution of energy efficient lamps (CFLs) and the establishment of a Solar Water Heater subsidy scheme in order to decrease electricity costs and save energy. (These measures have the potential to save approximately 50 MW per year).

TABLE 2
SHP feed-in tariffs in Rwanda

Plant installed capacity (MW)	Feed-in tariff (US$/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: Rwanda Utilities Regulatory Authority[13]

Legislation on small hydropower

A Renewable Energy Feed-In Tariff (REFIT) scheme was conducted by EWSA in close collaboration with RURA for hydropower plants which range from 50 kW up to 10 MW and are located within 10 km of the EWSA transmission network (Table 1). This was approved on 9 February 2012 (Table 2).[14]

Barriers to small hydropower development

Many of the challenges facing SHP development are linked to challenges facing the electricity sector in general. These include the following:

- The cost of financing infrastructure such as transmission lines and access roads to the potential sites;
- High tariffs due to high investment cost as a result of terrain and small water resources;
- Low energy capacity potential due to water resources available;
- Insufficient and unreliable power supply through lack of generation;
- Power utility lacking the capacity to increase access;
- Limited interest of private sector in power generation;
- High tariff per kWh limits demand for electricity and hinders economic development;
- Limited access for poor households to improved stoves and modern energy;
- Limited funds for programme development;
- Poor coordination between ministries and districts;
- Insufficient coordination of donor support;
- The judicial system remains relatively weak which means that the sanctity of contracts is not always upheld.

1.1.10 South Sudan

Tom Rennell, International Center on Small Hydro Power

Key facts

Population	12,042,910[1]
Area	644,329 km2[1]
Climate	South Sudan has an equatorial climate characterized by a rainy season, generally between May and October, followed by a dry season. The temperature on average is always high. July is the coolest month with average temperatures in Juba, the capital, between 20°C and 30°C while March is the warmest month with average temperatures between 23°C to 37°C.[1]
Topography	South Sudan is a landlocked country with plains in the north and centre rising to southern highlands along the border with Uganda and Kenya. The Imatong Mountains located in the south-east are home to Mount Kinyeti, the country's highest point at 3,187 m.[1]
Rain pattern	Rainfall is the heaviest in the upland areas of the south but diminishes in the north. The most rainfall is seen between May and October, but the rainy season can commence in April and extend until November. Typically, May is the wettest month with an average rainfall of 150 mm.[2]
General dissipation of rivers and other water sources	The White Nile and its tributaries dissect the country north to south with approximately 90 per cent of the area within the river's drainage basin. The centre of the country contains a large swampy area, the Sudd, of more than 100,000 km2 fed by the waters of the White Nile.[1]

Electricity sector overview

As of 2013, installed capacity was estimated to be approximately 27.4 MW though estimates vary between 25 MW and 30 MW.[3] 100 per cent of the country's capacity is understood to come from fossil-fuel-based thermal generators (Figure 1). Accurate data on installed capacity or annual electricity generation are difficult to obtain. However, both are considered to be extremely low with a per capita consumption of between just 1 kW and 3 kW compared to a regional average of 80 kW in sub-Saharan Africa.[4]

FIGURE 1

Installed electricity capacity in South Sudan (MW)

Source: Whiting et al.[3]

South Sudan is the world's newest country following independence from Sudan in 2011. The civil war which preceded independence and an ongoing political power struggle beginning in 2013 has left South Sudan severely underdeveloped, lacking in infrastructure and one of the poorest countries in the world. Only 1 per cent of the population and 7 per cent of the urban population are estimated to have access to power and then only intermittently during a 24-hour period.[5] The existing low level of power generation coupled with inefficient distribution networks has resulted in forced blackouts and load shedding in Juba. Most households and businesses have to rely on costly and unreliable captive power generation to satisfy their energy needs.[4] Only three of the state capitals, Juba, Malakal and Wau, have decentralized generation using a localized distribution network. Virtually no rural areas have electricity.[6] The Government has developed an ambitious programme aiming at an electrification rate of 70 to 80 per cent by 2020.[6]

The total capacity required to satisfy current demand is estimated to be approximately 450 MW. In the coming decades, this is expected to increase with a booming population and establishment of new industries with one estimate of 1,400 MW by 2030.[7] The country is planning to build about half a dozen hydropower and thermal power plants to help end the near permanent blackouts across the country and to attract investments in manufacturing industries.[9] China is thought to be providing the capital for significant investments in the energy sector to support both the oil and hydropower sectors.[5]

The formal energy sector is limited to the state-owned South Sudanese Electricity Cooperation (SSEC), a subsidiary of the Ministry of Energy and Mining (MEM), which operates eight diesel generators with a capacity of 1.5 MW each. SSEC is responsible for generation, transmission, distribution and sales of electrical energy to consumers in Juba, Malakal and Wau. It currently has approximately 15,000 domestic customers but no industrial or commercial consumers.[8] The Ministry of Electricity and Dams (MOED) is responsible for overall sector policy and strategy and is also involved in major projects in transmission and other large hydropower and regional integration projects. The Government plans to include the State Electricity Distribution Companies (SEDC) to manage local electric power distribution services (such as rural electric cooperatives) that can obtain supply from SSEC.

With the help of foreign aid such as United States Agency for International Development (USAID), South Sudan has built independent grid systems in cities such as Yei, Kepoeta, Malakal and Maridi. However, a large portion of the energy is from independently operated diesel generators belonging to businesses and private homes.[9] The African Development Bank (AfDB) recently granted South Sudan US$26 million to rehabilitate and expand the electricity distribution networks in the capital, Juba. This will include the construction of 145 km of low voltage and 87 km of 33 kV lines as well as 195 transformer stations.[6]

Those with access to the grid pay a high cost for electricity. A household connection costs between US$500 and US$600 and the average tariff is US$0.25/kWh. This is twice as much as what the average African consumer pays, five times what is paid in other developing countries, and more than double what is paid in Sudan. Overall, 87 per cent of firms identify the lack of electricity as a major impediment for their business and the high costs as a major hindrance to the growth of industrialization in South Sudan.[10]

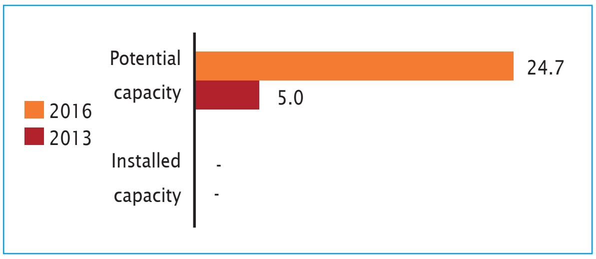
Small hydropower sector overview and potential

There is no official definition for SHP in South Sudan. However, this report assumes a definition of plants with an installed capacity up to 10 MW. There are currently no hydropower plants in South Sudan, small or otherwise though potential capacity of at least 24.7 MW has been estimated from a study of 16 identified sites on the Yei, Kaya, Kinyeti and Sue Rivers.[11] A planned 5-MW project on the Kinyeti was to go ahead but has been halted due to financial constraints. In comparison to the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, while installed capacity has remained at zero, estimated potential capacity has increased considerably (Figure 2).[12]

Despite having no operational hydropower plants, hydropower potential is thought to be significant with some estimates reaching in excess of 5,000 MW with a number of identified sites such as the Grand Fula which is estimated to have a potential capacity of 1,080 MW (Table 1).[14] A 40-MW site, Fula Rapids, has been funded by the AfDB, the Norwegian Government, the Emerging Africa Infrastructure Fund and the South Sudanese Government. Although there is no date set for construction, some 90 million South Sudanese Pounds (US$15 million*) was allocated to the national budget in June 2012 for its construction.[3,14] The Government has also signed a preliminary agreement with Chinese companies to provide most of the funds to construct the proposed 540 MW Bedden Dam hydropower plant, which is estimated to take seven years to build at a cost of US$1.4 billion.[15]

FIGURE 2

SHP capacities 2013-2016 in South Sudan (MW)



Sources: Chol,[11] *WSHPDR 2013*[12]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

Renewable energy policy

Since November 2015, there is no specific renewable energy policy in the country. However, the Government has openly stated that small hydropower (SHP) plants are planned as a medium- to long-term solution for the extension of national grids.[3] In 2011, the Government announced the South Sudan Development Plan (SSDP) 2011-2013 to promote growth and development. This was subsequently extended to 2016. The objective is to recover from the conflict and move to a fast-track development path by leveraging the country's vast natural resources. Under this development plan, large-scale infrastructure development is planned, particularly focusing on the provision of electricity and noting the need to develop hydropower potential with reference to the Fula dam project.[16] As part of South Sudan Vision 2040, the development of the country's hydropower potential is also mentioned as a key policy objective 'to build a prosperous, productive and innovative nation'.[17]

Barriers for small hydropower development

There are numerous challenges to the development of SHP in South Sudan mostly due to the continuing political tensions and fallout from the prolonged conflict. These include a lack of infrastructure; a lack of private investment in the sector; loss of meteorological and hydrological data due to the conflict; a lack of renewable energy policy or legislation; poor technical and institutional capacity; a lack of priority and focus on water resource management; and challenging accessibility due to the remoteness of potential sites.[18] The majority of these challenges are not

TABLE 1

Studied hydropower plants in South Sudan

Plant	Capacity (MW)	Location	Status quo
Grand Fula	1,080	Central Equatoria State	Feasibility study and EIA completed
Beden	540	Central Equatoria State	Feasibility study and EIA completed
Lakki	200	Central Equatoria State	Feasibility study and EIA completed
Shukole	200	Central Equatoria State	Feasibility study and EIA completed
Juba	120	Central Equatoria State	Studied
Fula Rapids	40	Central Equatoria State	Feasibility study and EIA completed
Sue	12-15	Western Bahr El-Ghazal State	Studied
Kinyeti	5	Eastern Equatoria State	Feasibility study completed

Source: Ministry of Electricity and Dams[14]
Note: Environmental Impact Assessment (EIA)

specific to SHP but to the development of the electricity sector in general. These challenges can be addressed by attracting private investment in the sector but in order to accomplish this, the Government will need to commit to vast improvements to the grid infrastructure and connectivity in the country before developing suitable legislation to provide financial incentives such as feed-in tariffs and power purchase agreements.

Notes

*Exchange rate US$0.16 to 1 South Sudanese pound

1.1.11 Uganda

Eva Maate Tusiime, Newplan Ltd

Key facts

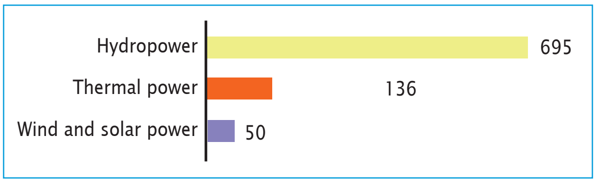
Population	34,900,000[1]
Area	241,000 km[2]
Climate	The climate is tropical and generally rainy with two dry seasons, December to February and June to August. The country is semi-arid in the north-east.[2] Average temperature is approximately 26°C. The maximum temperature ranges between 18°C and 31°C and minimum between 15°C and 23°C.[3]
Topography	The greater part of Uganda consists of a plateau between 800 and 2,000 m high and is rimmed by mountains. Along the western border, the country's highest point, Margherita Peak, reaches a height of 5,109 m while on the eastern border, Mount Elgon rises to 4,321 m. The lowest point is Lake Albert on the western border at 621 m.[2]
Rain pattern	Uganda receives the majority of its rain between March and June with rainfall of more than 500 mm during this season. The south is generally wetter than the north with the south-west receiving the heaviest rainfall. The north-east has the driest climate and is prone to droughts.[17]
General dissipation of rivers and other water sources	Uganda lies almost completely within the Nile basin. The Nile River (or Victoria Nile), which travels north-west from Lake Victoria to Lake Kyoga, receives River Kafu and continues flowing to Lake Albert. From here, it travels about 200 km to the South Sudan border. Major lakes include Lake Victoria, Lake Kyoga, Lake Edward and Lake Albert.[26]

Electricity sector overview

In 2014, total installed capacity was 881 MW. The majority (78.9 per cent) was from hydropower plants with thermal (15.4 per cent) and co-generation plants (5.7 per cent) contributing the remainder (Figure 1).[7]

FIGURE 1

Installed electricity capacity in Uganda by source (MW)



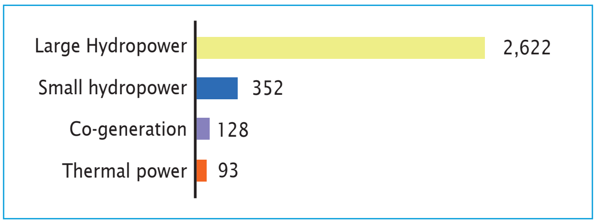
Source: Electricity Regulatory Authority[7]

As of the second quarter of 2015, annual generation was 3,195.5 GWh. Large hydropower contributed approximately 82 per cent, small hydropower (SHP) 11 per cent and co-generation and thermal plants provided the remainder (Figure 2).

The energy sector is characterized by a large dependence on biomass energy in the form of firewood (78.6 per cent), charcoal (5.6 per cent) and crop residue (4.7 per cent). Electricity contributes only 1.4 per cent while oil products take up the remaining 9.7 per cent.[5] In 2014, energy sales to Umeme, the country's biggest electricity distributor accounting for almost 99 per cent of electricity sales,

FIGURE 2

Annual electricity generation in Uganda by source (GWh)

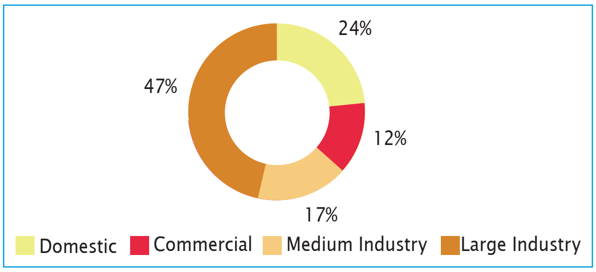


Source: Electricity Regulatory Authority[7]

reached over 2.275 TWh. Approximately 64 per cent of this was consumed by medium and large industries while domestic consumption was approximately 24 per cent and commercial consumption was approximately 12 per cent (Figure 3).

FIGURE 3

Energy sales to Umeme by sector in Uganda (%)



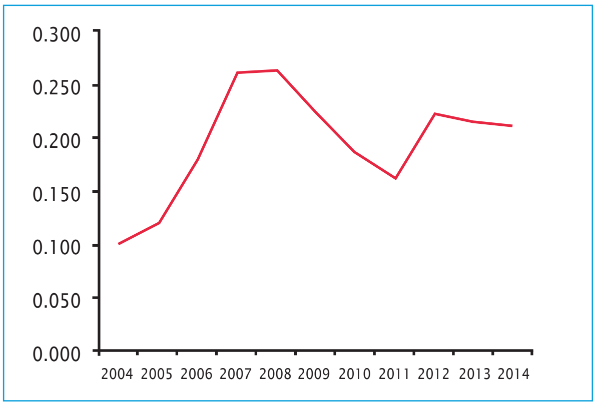
Source: Electricity Regulatory Authority[7]

Demand for power still exceeds supply and has been growing at an average rate of 10 per cent per annum.[5] Supply has, in recent years, been affected by erratic rainfall and periods of drought which has seen water levels fall. To mitigate these supply deficits, the Government procured thermal plants to cover the shortage. However, these proved costly. The Government increased subsidies to the sector to cushion consumers from price rises but when the Government defaulted on its obligations to the thermal Independent Power Producers (IPPs), the latter ceased generation leading to 12-hour electricity rationing (load-shedding).[6] Completion of the 250 MW Bujagali large hydropower plant in 2012, as well as the addition of plants such as Buseruka (9.5 MW) and Nyagak (3.5 MW,) provided considerable relief to the electricity demand.[6] However, the power-supply shortage still looms and predictions suggest it will grow steadily until the larger hydropower plants, such as Karuma (600 MW) and Isimba (180 MW) and Muzizi (46 MW), are commissioned.[11]

The country's electricity consumption is still one of the lowest in Sub-Saharan Africa. As of 2013, the electrification rate stood at 15 per cent with only a 9 per cent rural electrification rate.[5] Conversely, a 2012 report on the Government Rural Electrification Strategy and Plan placed rural electrification rates at 5 per cent.[8] In order to improve coverage and consumer accessibility to power, the Rural Electrification Agency (REA) was established with a target of 100 per cent electrification rate by 2035. The original 10-year Rural Electrification Strategic Plan (RESP) covering 2001-2010 only achieved a 5 per cent electrification rate. The current Rural Electrification Strategic Plan (2013-2022) aims to achieve rural electrification access of 22 per cent.[8] The electrification rate has been constrained by, among other issues, the slow pace of development in electricity generation, vandalism of distribution equipment, limited effective demand (especially in the rural areas), the high cost of service connections to rural households, a lack of interest by the private sector to enter the distribution market and the failure to educate the rural population on the benefits of electricity.[6,8]

FIGURE 4

Domestic tariffs (UMEME) in Uganda 2004-2014 (US$/kWh)



Source: Electricity Regulatory Authority[14]

The electricity sector is regulated by the Electricity Regulatory Authority (ERA), a corporate body which was established by the Electricity Act 1999. ERA regulates the generation, transmission, sale, export, import and distribution of electrical energy in Uganda.[9,10]

Transmission of power is controlled by the Uganda Electricity Transmission Company Limited (UETCL) which operates the system and owns transmission lines above 33 kV. UETCL is the bulk supplier and single buyer of power for the national grid in Uganda. Distribution of power is largely by Umeme Ltd, a private company with a 20-year concession. Distribution of power below 33 kV continues under the state-owned Uganda Electricity Distribution Company Limited (UEDCL). Other smaller and privately-owned distribution companies include Ferdsult Engineering Services Limited, West Nile Rural Electrification Company (WENRECO), Bundibugyo Energy Cooperative Society and Pader/Abim Community Multipurpose Energy Cooperative Society (PACMECS), all of which were also granted licences to distribute power to remote areas.[9,10]

TABLE 1

Regional domestic electricity tariff comparisons

Country	Price (US$/kWh)
Rwanda	0.32
Uganda	0.21
Tanzania	0.18
Kenya	0.16

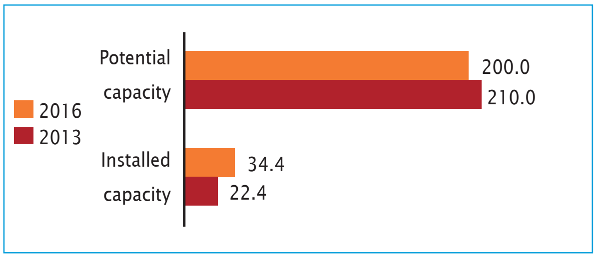
Sources: Various[14,15,16,17]

During the 1990s, power tariffs were generally stable and increasing marginally.[18] However, during the 2000s, prices started increasing, peaking during the middle of the decade to a high of US$0.25 per kWh. Between 2006 and 2011, electricity generation relied heavily on expensive thermal generators which necessitated the Government to increase subsidies to the electricity sector. By 2012, these subsidies were consuming approximately 37 per cent of the Ministry of Energy and Mineral Development budget and thermal generation accounted for 85 per cent of the total generation costs. The tariff was adjusted twice in 2006 but these increments were not sufficient to meet the financing gap. In 2012, the Government scrapped all subsidies to the electricity sector.[6]

In 2012, ERA announced the introduction of an Automatic Tariff Adjustment (ATA) which is responsive to changes in macroeconomic variables, namely the rate of inflation, foreign exchange and fuel prices.[12,13] This was implemented to enhance transparency in the power sector as well as enhance security of supply and reliability of power in order to overcome load shedding.[19] With this system, the tariffs are adjusted every quarter. As of 2015, domestic tariffs in Uganda were 531.5 Ugandan Shillings/kWh (US$0.212) and considerably more expensive than neighbouring countries Kenya and Tanzania (Table 1). Figure 5 shows adjustments to Umeme's domestic tariff

FIGURE 5

SHP installed and potential capacities in Uganda 2013-2016



Sources: Electricity Regulatory Authority,[9] *WSHPDR 2013*[27]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016.* The potential capacity considers SHP of 20 MW or less, while the installed capacity only considers SHP of 10 MW or less. Additionally, the decrease in potential is due to more publicly available data.

for between 2013 and 2016.

Generation tariffs paid by the Uganda Electricity Transmission Company Limited (UETCL) for bulk energy purchases are dependent on capacity or energy. UETCL pays a capacity price for large hydropower plants while the charge for smaller plants is for energy per kWh.[20] Generation tariffs as of 2014 are shown in Table 2.

TABLE 2

Peak generation tariffs in Uganda 2014

Source	Generation tariff	
	Bulk (US$/MWh)	Small (US$/kWh)
Bujagali	5.89	—
Eskom	11.52	—
Other SHP	—	0.0421-0.135
Thermal generation	237-267	—
Co-generation	—	0.0496-0.081

Source: Electricity Regulatory Authority[20]

The electricity sector has seen some improvements partly due to renewed government interest. However, challenges still remain, particularly in the generation and distribution areas. With regard to generation, challenges include attracting investment from the private sector and corruption in the tendering processes. In distribution, challenges include high energy losses and the reluctance by private investors to extend the grid to remote areas.[6]

Notwithstanding the above, the Government is promoting the development of renewable energy through initiatives such as the development of Renewable Energy Feed-In Tariff (REFIT) guidelines and power purchase agreements that make energy businesses more profitable and predictable.[13]

Small hydropower sector overview and potential

Uganda defines SHP as plants with an installed capacity of 20 MW or less. Installed capacity of SHP plants less than 20 MW in Uganda is 65.4 MW (Table 3), approximately 9.4 per cent of the total hydropower capacity. Installed capacity less than 10 MW is 34.4 MW. The total potential capacity for plants less than 20 MW is estimated to be at least 200 MW.[9] This suggests that, for plants up to 20 MW, approximately 31 per cent of total potential has been developed.[9] Since 2013, the estimated potential has not changed but the installed capacity (less than 10 MW) has increased by over 50 per cent (Figure 5).[27] Current operational SHP plants are shown in Table 3.

TABLE 3

Operational SHP plants less than 20 MW in Uganda

Site	District	Status / ownership	Installed capacity (MW)
Mpanga PowerStation	Kamwenge	Africa Ems Mpanga	18.00
Mubuku II/Bugoye Hydropower Project	Kasese	Tronder Power Ltd	13.00
Mubuku III	Kasese	Kasese Cobalt Company Ltd	9.90
Buseruka	Hoima	Hydromax Ltd	9.00
Ishasha Hydropower station	Kanungu	Ecopower Ltd	6.60
Mubuku I (Tibet Hima Mining Co.)	Kasese	Kilembe Mines Ltd	5.40
Nyagak	Nebbi	Wenreco	3.50
Total			65.40

Source: Electricity Regulatory Authority[9]

Many potential sites for SHP development exist but they are located in areas that have no grid access. SHP sites that have been identified for development are shown in Table 4. A number of studies for which ERA has issued permits are also ongoing in different sites scattered throughout the country.[9]

There are plans to refurbish the 1-MW Maziba hydropower plant that was shut down in 2001 due to sediment problems. Designs have been completed and refurbishment works are expected to commence later in 2015. Two sites with a combined installed capacity of 25.2 MW are planned for construction in the future (Table 4).

Most of the total hydropower potential in Uganda, which is estimated at about 2,000 MW, is situated along the River Nile. Only 630 MW of large hydropower (Bujagali, Kira and Nalubaale) has been developed to date, leaving well over 1,300 MW of (mainly large) hydropower potential. The Government has set up the Uganda Energy Credit Capitalization Company (UECCC) which offers credit and liquidity support to regulated financial institutions. UECCC has entered into an agreement with the German Agency for International Cooperation (GIZ), the Private

TABLE 4

Potential and planned SHP plants less than 20 MW

Site	District	Status / ownership	Installed capacity (MW)
Kikagati	Isingiro District	License approved (Kikagati Power Company Ltd)	16.00
Nyamgasani	Kasese	Under study	15.00
Nyamwamba	Kasese	License approved (South Asia Energy Management Systems LLC)	9.20
Kyambura	Bushenyi	Under study	8.30
Sindoro	Bundibugyo	Under study	7.50
Nengo Bridge	Rukungiri	Under study	6.70
Muvumba	Kabale	Under study	4.50
Nyagak III	Zombo	Under study	4.40
Nyamabuye	Kisoro	Under study	2.20
Ela	Arua	No studies	1.50
Ririma	Kapchorwa	No studies	1.50
Rwigo	Bundibugyo	No studies	0.48
Nyarwodo	Nebbi	No studies	0.40
Tokwe	Bundibugyo	Preliminary technical studies carried out.	0.40
Agoi	Arua	No studies	0.35
Kitumba	Kabale	No studies	0.20
Amua	Moyo	No studies	0.18
Ngiti	Bundibugyo	Preliminary technical studies carried out.	0.15
Manafwa	Mbale	Preliminary technical studies carried out.	0.15
Leya	Moyo	No studies	0.12
Nyakibale	Rukungiri	No studies	0.10
Miria Adua	Arua	No studies	0.10

Source: Electricity Regulatory Authority[9]

Sector Foundation of Uganda (PSFU) and the Rural Electrification Agency (REA) to implement the Private Sector Participation in Mini-Hydropower Development (PSP Hydro) initiative. The programme aims to support three to five private mini-hydropower projects for rural electrification with capacities not exceeding 1 MW each. Uganda is also to benefit from the UN Sustainable Energy for All (SE4ALL) initiative which aims to provide clean energy to rural areas.[9,13,21]

Renewable energy policy

The overall objective of the Ugandan 2007 Renewable Energy Policy is to diversify the energy supply sources and technologies in the country. The policy aims "to increase the use of modern renewable energy, from the current 4 per cent to 61 per cent of the total energy consumption by the year 2017".[22]

The main features of the policy are the following:

- Introduction of feed-in tariffs;
- Standardized Power Purchase Agreements (PPAs);
- Tax incentives on renewable energy technologies;
- Obligation of fossil fuels companies to mix products with up to 20 per cent biofuels.

To achieve the policy objectives, the Government set out the following strategies:

- Maintain and improve the responsiveness of the legal and institutional framework to promote renewable energy investment.
- Establish an appropriate financing and fiscal policy framework for renewable energy technology investment.
- Mainstream poverty eradication, equitable distribution and gender issues in renewable energy strategies.
- Acquire and disseminate information in order to raise public awareness and attract investment in renewable energy sources and technologies.
- Promote research and development, international cooperation, technology transfers and adoption of standards in renewable energy technologies.
- Utilize biomass energy efficiently so as to contribute to the management of the resource in a sustainable manner.
- Promote the sustainable production and utilization of biofuels.
- Promote the conversion of municipal and industrial waste to energy.[22,23]

TABLE 5

Feed-in tariffs and capacity limits for renewable energy plants in Uganda

Technology	Tariff (US$/ kWh)	Operation and maintenance costs (%)	Cumulative capacity limits (MW)				Payment period (yrs)
			2013	2014	2015	2016	
Hydro (9 MW-20 MW)	0.09	7.61	30	90	135.0	180.0	20
Hydro (1 MW-9 MW)	Linear tariff	7.24	30	75	105.0	135.0	20
Hydro (500 kW-1 MW)	0.12	7.08	1	2	2.5	5.5	20
Bagasse	0.08	22.65	30	70	95.0	120.0	20
Biomass (MSW)	0.10	16.23	5	15	25.0	45.0	20
Biogas	0.12	19.23	5	15	25.0	45.0	20
Land fill gas	0.09	19.71	0	10	20.0	40.0	20
Geothermal	0.08	4.29	10	30	50.0	75.0	20
Wind	0.12	6.34	25	75	100.0	150.0	20

Source: Electricity Regulatory Authority[9]

The Renewable Energy Feed-in Tariff (REFIT) scheme was first introduced after establishment of the 2007 Renewable Energy Policy. However, following limited uptake by project developers, it was reviewed in 2010 and new tariffs were developed based on updated costs of production.[3,24,25]

The Renewable Energy institutional framework consists of the following:

- The Electricity Regulatory Authority (ERA), charged with managing and implementing the REFIT.
- The Uganda Electricity Transmission Company Limited (UETCL), the system operator and single buyer. UETCL issues and signs the PPAs.
- Renewable Energy Electricity Generators (subject to fulfilment of all necessary conditions).
- Distribution licence holders.

Legislation on small hydropower

The renewable energy generators that qualify for REFIT are as follows:

- Small hydro, geothermal, bagasse, landfill gas, biogas, biomass, wind and solar.
- Projects of 0.5-20 MW. Those greater than 20 MW negotiate a tariff on a case-by-case basis.
- Plants including additional capacity resulting from project modernization, repowering and expansion of existing sites but excluding existing generation capacity.
- Projects connected to the national grid. Off-grid projects may be included in future developments of the REFIT.

The tariffs, shown in Table 5, are set according to the year in which the licence is issued.

Uganda has developed several interventions particularly aimed at promoting renewable energy development. The Renewable Energy Feed-in Tariffs (REFITs) guidelines were developed to encourage and support greater participation by the private sector. These guidelines were for small power projects with capacity of less than 20 MW. In addition, the Power Purchase Agreements (PPAs) have been standardized so that investors do not have to go through lengthy negotiations. In 2013, Uganda co-operated with development partners to create a tariff top-up programme called the Global Energy Transfer Feed-in Tariff (GETFIT) which would help stabilize the Ugandan power sector finances by adding low cost generation capacity. To date, through GETFIT, 150 MW has been contracted through 15 projects, 80 per cent of which were SHP projects below 10 MW. The premium payments as of 2013 are given in Table 6.

TABLE 6

2013 premium REFIT and GETFiT payments for SHP

Capacity	REFIT tariff (US$/kWh)	GETFiT premium (US$/kWh)
Hydro (9-20 MW)	0.08	0.02
Hydro (1-9 MW)	0.082-0.092	0.02

Source: Electricity Regulatory Authority[9]
Note: Range-actual tariffs provided in linear tariff calculation

As previously mentioned, there has been a lot of government interest in the renewable energy sector with further incentives such as the GETFIT programme, UECCC and SE4ALL introduced to encourage private sector participation. This notwithstanding, developers still mention high upfront costs, limited access to early-stage support and equity investment as challenges that still need to be overcome.[21]

In generation, demand still outstrips supply whereas in distribution, losses are still high so anticipated private-sector participation in the sector has been slower. Thus this slows down the rate of rural electrification. In addition, non-technical losses due to power thefts still remain. To overcome these challenges, the Government needs to attract more investment in generation and devise interventions that would secure supply security. The Government intends to take on greater responsibility in the rural electrification schemes through the Rural Electrification Strategy and Plan 2013-2022.[6,8,18]

Barriers to small hydropower development

There are a number of challenges facing SHP development in Uganda including the following:

- High upfront costs and limited access to early-stage support and equity investment.
- The system of land acquisition, which is quite complex, slow, bureaucratic and lacks transparency, affects the overall project cost.
- High perceived risks by investors as to whether the transmission company will honour invoices over the duration of their licence as was the case in 2011 when delayed payments by UETCL prompted some generation stations to turn off generation. As a result, IPPs are now asking for payment guarantees and this in itself may not be sustainable.
- Due to the perceived high risks, commercial lenders are only willing to lend at very high interest rates. They also require other forms of insurance guarantees to mitigate the risk of non-payment such as the Escrow requirements or Debt Service Reserve Accounts, which increases the cost of debt.
- More investment is still needed in the distribution sector to match the generation and transmission investments. At present, the distribution losses are still high and non-technical losses (electricity theft) are still rampant.
- Grid access remains a big challenge. There is still a need for significant investment in public road access to the generation sites (which are mostly in remote areas) to enable connection to the national grid.
- Several institutions with specific roles have been set up in the electricity sector. However, these institutions need to grow their technical capacity in all areas including planning, design and construction of hydropower plants.[13,21]

1.1.12 United Republic of Tanzania

Emmanuel G. Michael-Biririza*

Key facts

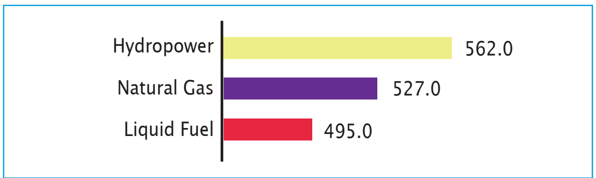
Population	49,639,138[1]
Area	945,749 km[2]
Climate	The climate is tropical (hot and humid) along the coast with a rainy season between March and May. In the highlands, the climate is temperate with short rains (Vuli) between November and December and long rains (Masika) between February and May.[2]
Topography	Plains along the coast lead to a central plateau and highlands in the north and south. The highest peak is Mount Kilimanjaro at 5,895 m in the north-east of the country.[3]
Rain pattern	The mean annual rainfall varies between 500 mm and more than 2,500 mm. The average duration of the dry season is between five to six months. Rainfall patterns have recently become much more unpredictable with some regions receiving extremely low or extremely high rainfall per year.[4]
General dissipation of rivers and other water sources	Tanzania is surrounded by water bodies covering 59,050 km[2] or approximately 6 per cent of the total area. 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 River, Great Ruaha River, Kagera River, Ruvuma River, Wami River, Malagarasi River, Mara River and Pangani River.[3]

Electricity sector overview

In April 2014, the total installed capacity of grid-connected electricity generation in Tanzania was 1,597 MW; and it comprised hydropower at 562 MW, natural gas at 527 MW, liquid fuel at 495 MW and imports from Uganda, Zambia and Kenya at 8 MW, 5 MW and 0.85 MW repectively.[5] The country also has the potential for coal and uranium alongside renewable energy resources. For many years, the electricity sector in Tanzania was dominated by hydropower. However additional thermal plants were employed following a severe drought in 2004. The generation mix has also significantly changed following the discovery of natural gas reserves.

FIGURE 1

Installed electricity capacity in Tanzania by source (MW)



Source: Ministry of Energy and Minerals[5] (2013)

As of 2014, the electrification rate stood at 24 per cent countrywide and 11 per cent for rural areas. Efforts are being made to increase access in rural areas. The Government aims to achieve 30 per cent access by 2015, 50 per cent by 2035 and 70 per cent by 2033. Up until the last decade, rural electrification had been solely the responsibility of the Government with support development partners such as the United Nations Industrial Development Organization (UNIDO). The Rural Energy Agency was established by the Rural Energy Act of 2005 to oversee the implementation of rural electrification projects using the Rural Energy Fund.

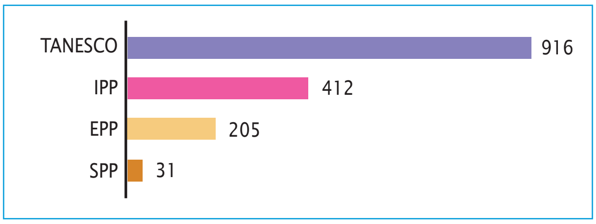
The electricity sector in Tanzania is dominated by the state-owned Tanzania Electric Supply Company Limited (TANESCO) which was established in 1964. It was set up in a vertically integrated structure and is responsible for generation, transmission, distribution and supply. The grid network in Tanzania covers all main town centres including district town centres. TANESCO operates the grid network as well as isolated supply systems in Kagera, Kigoma, Rukwa, Ruvuma, Mtwara and Lindi.

Due to slow development in the sector and the general global trend in the electricity supply industry, the Government, through the National Energy Policy, lifted the monopoly held by TANESCO in 1992 to allow involvement of the private sector in the electricity industry. This major policy reform has enabled independent power producers (IPP) to operate in the electricity generation sector and for interconnections with Zambia and Uganda to allow imports of relatively small amounts of electricity.

In 2013, TANESCO owned almost 60 per cent (916 MW) of installed capacity including all the large hydropower plants. IPPs accounted for 26 per cent of installed capacity, emergency power producers (EPP) 13 per cent and small power producers (SPP) just 2 per cent.[4]

FIGURE 2

Installed electricity capacity in Tanzania by producers (MW)



Source: Ministry of Energy and Minerals[5]

Electricity tariffs for consumers are divided into groups depending on the use of electricity. The average electricity tariff for domestic consumers is US$0.15/kWh. A solid framework was established for the trade of electricity between producers and the regulation of TANESCO by the Energy and Water Utility Regulatory Authority (EWURA). For small power projects below 10 MW, there are Standardized Power Purchase Agreements (SPPA) and an established technology specific feed-in tariff. For SHP projects, the tariff is also subdivided according to installed capacity. The tariff is US$0.155 and US$0.085/kWh for 100 kW and 10 MW installed capacities respectively.[6]

Small hydropower sector overview and potential

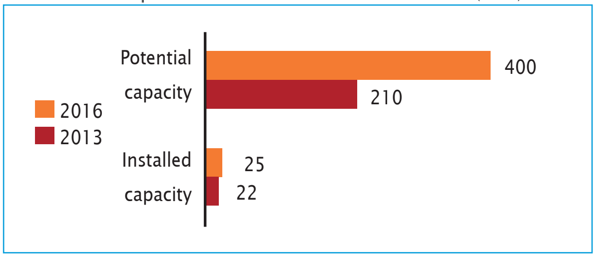
Tanzania defines small hydropower (SHP) as plants less than 10 MW. The current installed capacity is estimated at around 25 MW, and includes SHP plants which are isolated or undocumented. The estimated total potential capacity is at 400 MW, indicating that approximately 6 per cent has been developed.[9] Since 2013, capacity has risen by approximately 10 per cent while estimated potential has almost doubled (Figure 3).[7]

Approximately 45 plants with a total installed capacity of 25 MW have been developed, of which only around 20 MW are currently in operation (Table 1). Approximately 93 per cent of the plants have capacities lower than 5 MW (Figure 4).[8] As already noted most SHP plants were installed by donors, missionaries and the Government. Currently, TANESCO owns 15 per cent of the SHP plants and private investors own 85 per cent but TANESCO owns 69 per cent in terms of installed capacity.[9] The database of the Rural Energy Agency shows that 13 projects with a total capacity of 28.8 MW are in various stages of development.[10]

The total potential for SHP generation is estimated at 400 MW. Studies, including economic analysis, show a number of sites that could produce electricity at competitive costs to supply power to the national grid and through mini-grids to villages in the community. Areas with high potential include the Rift Valley escarpments in the west, south-west and north-east. Central Tanzania is relatively flat and dry, and has no hydropower potential. Studies show that 14 out of 25 administrative regions of mainland Tanzania have potential SHP resources but only four regions, Mbeya, Njombe, Iringa and Kilimanjaro, have significantly developed these resources.

FIGURE 3

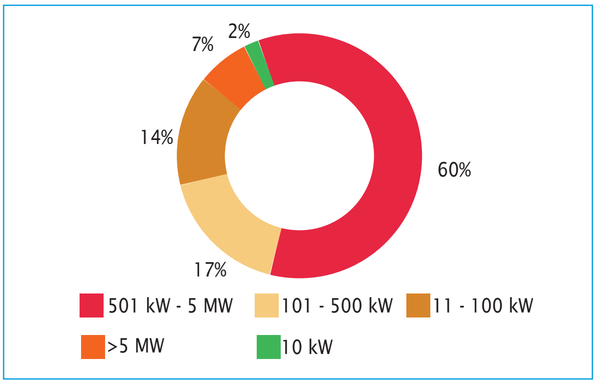
SHP capacities 2013-2016 in Tanzania (MW)



Sources: Various[7,9,10,11]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

FIGURE 4

Number of operational SHP plants in Tanzania by capacity (%)



Source: TANESCO[8]

An ongoing SHP mapping project for Tanzania is being carried out by various consultants in close collaboration with the Rural Energy Agency and is financed by the World Bank through the Energy Sector Management Assistance Programme (ESMAP). A total of 375 SHP sites with a total capacity of approximately 400 MW have been identified. Survey studies of new potential sites and confirmation of existing information have been completed for the Rukwa, Kagera and Ruvuma regions. Further studies in collaboration with the Rural Energy Agency have been carried out in the Iringa, Njombe, Mbeya, Morogoro and Kigoma regions.

The Rural Electrification Master Plan study on mini-hydropower potential was commissioned by the Ministry of Energy and Minerals (MEM) and implemented by Tanzania Electric Supply Company Limited (TANESCO). The objectives were to examine the technical, economic, social and environmental aspects of a lowest-cost solution of supplying electricity to unelectrified rural areas, defining appropriate programmes and priority

TABLE 1
Installed SHP plants in Tanzania

Site name	District / region	Year installed	Installed capacity (kW)	Developer / owner
Nyumba ya Mungu	Same/Kilimanjaro	—	8,000.0	TANESCO
Mwenga	Mufindi/Iringa	2010	4,000.0	Mufindi Tea Company
Tosamaganga	Iringa	1951	1,220.0	TANESCO
Kikuletwa	Moshi/Kilimanjaro	—	1,160.0	TANESCO
Mbangamao	Mbinga/Ruvuma	2015	1,000.0	Andoya Hydroelectric Power Company
Mbingu	Ifakara/Morogoro	2009	850.0	Mbingu sisters convent
Uwemba	Njombe	1971	800.0	Benedict Fathers
Mbarari	Mbarari/Mbeya	1972	700.0	NAFCO/Government
Mngeta	Ifakara/Morogoro	—	600.0	Government parastatal
Uvinza Mine	Uvinza/Kigoma	—	600.0	Private
Chipole	Mbinga/Rukwa	—	400.0	RC Mission
Mbalizi	Mbalizi/Mbeya	1958	340.0	TANESCO
Mawengi	Ludewa/Njombe	2013	300.0	RC Njombe diocese and village community
Lupa	Ifakara/Morogoro	—	200.0	Mission
Bulongwa	Njombe	—	180.0	Mission (not specified)
Mavanga	Ludewa/Njombe	2002	150.0	RC mission/Mavanga Village community
Matembwe	Njombe	1986	150.0	RC mission/CEFA/Matembwe Village Community
Lugarawa	Ludewa/Njombe	1979	140.0	RC Mission
Ndolela	Songea Rural/Ruvuma	—	100.0	Tea Estate
Kabanga	Kasulu/Kigoma	—	100.0	Mission
Maguu	Mbinga/Ruvuma	—	100.0	Mission
Ndolage	Bukoba/Kagera	1961	55.0	RC Mission
Kitai	Songea/Ruvuma	1976	45.0	Prisons Dept/ Government
Kaengesa	Sumbawanga/Rukwa	1967	44.0	RC Mission
Ikonda	Makete/Njombe	1975	40.0	RC Mission
Nyangao	Nyangao/Lindi	—	38.8	Mission (not specified)
Peramiho	Songea Rural/Ruvuma	1962	34.6	Benedict Fathers
Rungwe	Tukuyu/Mbeya	1964	21.2	Moravian Mission
Matombo	Matombo/Morogoro	2013	20.0	Village community
Nyagao	Lindi	1974	15.8	RC Mission
Isoko	Tukuyu/Mbeya	1973	15.5	Moravian Mission
Ngaresero	Arusha	1982	15.0	M.H Leach
Ndanda	Lindi	—	14.4	Mission (not specified)
Kinko	Lushoto/Tanga	2006	10.0	Village community
Isoko	Tukuyu/Mbeya	—	7.3	Mission (not specified)
Sakare	Soni/Tanga	1948	6.3	Benedict Fathers

Sources: Michael,[9] , Kassana et al.[11]
Note: This table is not comprehensive.

projects for expansion of the electricity networks and development of renewable energy supply systems for the country over 15 to 20 years. In addition to other sources of electricity, five SHP sites from the SHP database were appraised during this study. Table 2 provides a list of the sites in the various stages of development.

All projects in Tanzania need to demonstrate that they take care of the environmental issues in their plans. Under these regulations, it is mandatory to undertake a full Environmental Impact Assessment (EIA) for all projects with capacities above 1 MW. For projects with capacities below 1 MW, it is necessary to take into consideration

Recent development of hydropower sites in Tanzania (kW)

TABLE 2

List of sites in the various stages of development

Name	Developer	Potential capacity (kW)	Project status
Uvinza hydropower Project (Kigoma) – Malagarasi	Yet to be determined	8,000-24,000	Feasibility level
Mandera hydropower (Korogwe)	Yet to be determined	21,000	Feasibility (1995)
Kilocha (Ruhudji) SHP (Iringa)	Njombe Roman Catholic Church	10,000	Feasibility level
Kitonga SHP (Iringa)	Kitonga Electric Co	10,000	Feasibility level
Momba hydro project (Mbozi)	Mbozi DC & CAMS SKY AFRICA	10,000	Feasibility level
Nakatuta SHP (Songea Rural)	Yet to be determined	9,200	Feasibility studies carried out (D)
Kiwira – Malasusa falls(Rungwe)	Mkonge Energy Systems	8,000	Feasibility level
Kikuletwa II (Hai)	Community Development Cooperation	8,000	Feasibility level
Kitiwaka hydro Project (Ludewa)	Ludewa DC & CAMS SKY AFRICA	8,000	Feasibility level
Nzovwe SHP (Sumbawanga)		8,000	Feasibility Level
Kimani SHP	Yet to be determined	7,000	Reconnaissance level
Tulila small hydropower (Songea Rural)	Benedictine Sisters – Chipole	6,500	Construction
Saadani SHP (Mufindi)	Fox Company Limited	5,900	Mobilising Resources
Luswisi (ileje)	Kikundi cha Mazingiralleje Mashariki – CBO	3,200	Feasibility level
Kwitanda hydro Project (Tunduru)	Kwitanda Community	3,000	Identified
Sunda Falls (Tunduru)	Tunduru DC & CAMS SKY AFRICA	3,000	Feasibility level
Lingatunda (Mahanje – Songea Rural)	RC Parish Mahanje	3,000	Feasibility level
Ilondo Hydropower Project (Mufindi)	Fox Company Limited	2,700	Mobilising Resources
Mngazi hydropower (Morogoro)	TBA	2,100	Feasibility Level
Nyakifunga Falls (Njombe)	Yet to be determined	2,050	Feasibility level
Isigula SHP (Mkiu – Mlangali) – Ludewa	Kisangani Group	2,000	Pre-feasibility
Mtambo SHP (Mpanda)	Electromechanical Systems	2,000	Feasibility level
Lwega Small Hydropower Project (Mpanda)	MOFAJUS Investments	2,000	Feasibility level
Pinyinyi SHP (Ngorongoro)		1,900	Feasibility Level
Luiche hydropower Project (Sumbawanga)	Ulaya Hydro & Windmill Technology	1,610	Feasibility Level
Balali SHP (Njombe)	Yet to be determined	1,500	Reconnaissance level
Darakuta SHP (Babati)	Darakuta Farm Ltd	1,350	Detail design completed
Luganga Iringa)	Makete Power Services	1,200	Feasibility level
Nkwiro Shp (Sumbawanga)	Ulaya Hydro & Windmill Technology	1,165	Feasibility level
Mbinga Mtambazi SHP (Ruvuma)	Andoya Hydro Electric Company Ltd	1,000	Under construction
Yovi Shp (Kilosa)	Msolwa Stigmate Fathers & Brothers	950	Detail design completed
Ndugu hydropower Project	LM Investments	900	Identified potential
Nyalawa hydro project (Mufindi)	Yet to be determined	835	Pre-feasibility
Lupali SHP-MG (Njombe)	Benedictine Sisters – Imiliwaha	640	Implementation
Macheke Falls (Mlangali) – Ludewa	MLADEA/LUDEA	420	Feasibility level
Luaita hydro Project (Mbinga)	Yet to be determined	400	Identified potential
Mtombozi SHP (Morogoro)	Yet to be determined	380	Pre-feasibility
Makurukuru (Lumeme River) SHP	Andoya Hydro Electric Company Ltd	350	Identified potential
Mugali River – Maruruma (Mufindi)	Masana Village	300	Reconnaissance level
Kingerikiti (Lumeme River – Mbinga) SHP	Andoya Hydro Electric Company Ltd	300	Identified potential
Simike Small Hydropower Project (Rungwe)	RETDCO	300	Feasibility level
Mwoga SHP (Kigoma)	Kasulu District Council	300	Feasibility level
Nole (Njombe)	RC Parish Nole	300	Feasibility level
Mpando SHP (Njombe)	CHAMAI	220	Feasibility Level
Ilundo hydropower project (Rungwe)	Ilundo Community	200	Feasibility level
Malindindo (Mbinga)	Malindindo Community	200	Feasibility level
Ijangala Shp (Makete)	Tandala Diaconical Centre	200	Detail design stage
Mmanga minhydroplant (Morogoro)	Tawa Ward Community	50	Pilot, newly identified
Wangama (Njombe)	Wangama Community	48	Under construction
Kindimba SHP (Mbinga)	Mbinga Community (CBO)	40	Completed
Magoda (Njombe)	Magoda Community	25	Under construction
Igominyi (Njombe)	Igominyi Community	10	Under construction
Limage (Njombe)	Limage Community	10	Under construction

Sources: Rural Energy Agency;[10] author's compilation the environmental issues in their plans by undertaking simplistic Environmental Impact Studies (EIS). The National Environmental Management Council (NEMC) is responsible for approving the EIA/EIS conducted.

Recently, UNIDO has supported the establishment of a SHP centre located at the College of Engineering, University of Dar es Salaam intended to be a centre for all issues related to SHP development in the country.

Renewable energy policy

There is no existing policy for renewable energy in Tanzania. The Government, through its Ministry of Energy and Minerals, is in the process of reviewing the National Energy Policy which includes issues related to renewable energy.

As part of its agenda to make the renewable energy industry an integral part of its rural energy and power sector development strategies, the Government has issued the following policies:

- The rural electrification policy statement which indicates that all lower-cost technical options should be considered, including renewable energy.
- The Rural Energy Act (2005) that established the Rural Energy Agency and Fund (REA/F) with the main task of promoting access to modern energy services and allocating performance-based subsidies for rural energy including renewable energy systems.
- The Energy and Water Utility Regulatory Authority Act (2001) that gives the responsibility of tariff setting to the regulator and also affects the independent renewable energy power producers.

To ensure adequate supply, the Electricity Act (2008) created procedures for providing electricity from different sources. EWURA has designed a model for Standardized Small Power Purchase Agreement/Tariff (SPPA/T) for private producers with project capacities lower than 10 MW. The SPPA is reviewed annually to reflect operating costs. Currently, however, the Government (through EWURA) is finalizing the Renewable Energy Feed-In Tariff which will be reflective of the technology used as opposed to the SPPA which is technology-neutral.

Barriers to small hydropower development

The key barriers hindering the development of SHP in Tanzania can be summarized as follows:

- Lack of infrastructure in the design and manufacture of turbines, installation and operation.
- Lack of access to appropriate technologies for pico-, micro-, mini- and small hydropower. Lack of indigenous technology and low level of technology to harness the existing hydropower potential. Networking, best practices sharing and information dissemination through forums and conferences are necessary.
- Lack of local capacity (local skills and know-how as well as the lack of self-initiatives) in developing SHP projects. There is a need for technical assistance in the planning, development and implementation of SHP projects.
- Insufficient information about potential sites (hydrological data).
- Inadequate SHP awareness, incentives and motivation.
- Inadequate private sector participation in SHP development.
- Lack of joint ventures (public and private sector partnerships).
- Lack of investment capital to develop the existing hydropower potentials. Records show that most of the developed capacity in the African region was realized through grants or soft loans from foreign development institutions or countries. Very few sites have been developed through internal resources of the related countries.
- High competition for investment capital worldwide.

* The author is a former employee of UNIDO.

1.1.13 Zambia

Mundia Simainga, ZESCO LTD

Key facts

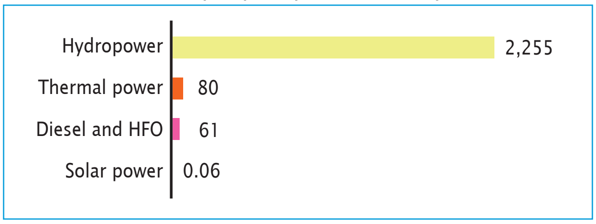
Population	15,721,343[1]
Area	752,612 km²
Climate	There are three seasons: cool and dry from May to August; hot and dry from September to November; and warm and wet from December to April. In the warm wet season, frequent heavy showers and thunderstorms occur followed by spells of bright sunshine. Average temperatures are moderated by the height of the plateau. There is occasional frost in the cool season with temperatures varying between 15°C and 27°C in the morning and between 6°C and 10°C in the evening. During the hot season, maximum temperatures range between 27°C and 35°C.[2]
Topography	Zambia is situated on the great plateau of central Africa at an average altitude of 1,200 m with a higher plateau rising in the east. The country has three main topographical features: mountains with an altitude of at least 1,500 m, a plateau with altitudes between 900 and 1,500 m and lowlands with altitudes between 400 and 900 m.[2,3]
Rain pattern	Zambia receives moderate rainfall with an annual average of 1,000 mm. This ranges between approximately 600 mm in the south and over 1,400 mm in the north. There is almost no rainfall in June, July and August. The driest areas are in the far south-west, the Luangwa River and middle Zambezi River valleys; parts of which are considered semi-arid.[2]
General dissipation of rivers and other water sources	The country has five main river basins: the Zambezi, Kafue, Luangwa, Luapula and Chambeshi. The five main river basins incorporate several smaller river basins. Major lakes include Tanganyika, Mweru, Mweru Wa Ntipa, Bangweulu. Man-made lakes include Kariba and Itezhi-tezhi.[2,3]

Electricity sector overview

Energy sources in Zambia include electricity, petroleum, coal, biomass and other renewable energy sources. While petroleum is wholly imported, the country is largely self-sufficient in the other resources with substantial undeveloped reserves. In 2014, installed electricity capacity in Zambia was 2,396 MW.[7]

FIGURE 1

Installed electricity capacity in Zambia by source (MW)



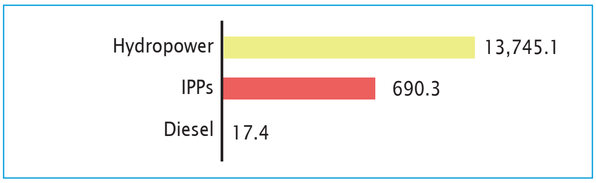
Source: Energy Regulation Board[7]

Hydropower accounts for more than 95 per cent and contributes 2,255 MW, largely from three main hydropower plants situated in the south: Kafue Gorge (990 MW), Kariba North Bank (1,080 MW) and Victoria Falls (108 MW). Together they account for 2,178 MW, or approximately 91 per cent of total installed capacity. All three are operated by the Zambia Electricity Supply Corporation (ZESCO), the state-owned, vertically integrated electric company. The remaining capacity consists of thermal power plants (80 MW) and diesel and heavy fuel oil plants (61 MW). Solar energy sources contribute just 0.06 MW (Figure 1).[7] Privately-owned plants account for less than 6 per cent of installed capacity.[8]

In 2014, the total generation was 14,453 GWh, the majority (13,638 GWh) of which came from the three main hydropower plants. The remaining hydropower plants supplied 107.1 GWh, diesel contributed 17.36 GWh and three independent power producers (IPP), LHPC, Ndola Energy Company and Zengamina Power, provided 690.3 GWh (Figure 2).[7]

FIGURE 2

Annual electricity generation in Zambia by source (GWh)



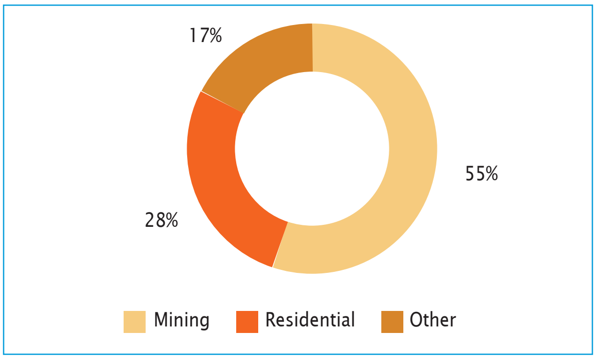
Source: Energy Regulation Board[7]

In 2014, the mining sector was the biggest consumer of electricity with approximately 55 per cent of total consumption. The residential sector accounts for approximately 27.5 per cent with remaining sectors (including agriculture, financial services, trade and manufacturing) approximately 18 per cent (Figure 3).

In 2013, the national electrification rate was approximately 25 per cent with 49.3 per cent in urban areas and 3.2 per cent in rural areas.[7] The Government plans to increase the national electrification rate to 66 per cent of households by 2030 with urban areas achieving 90 per cent and rural areas 51 per cent.[11]

FIGURE 3

Annual electricity consumption by sector in Zambia (%)

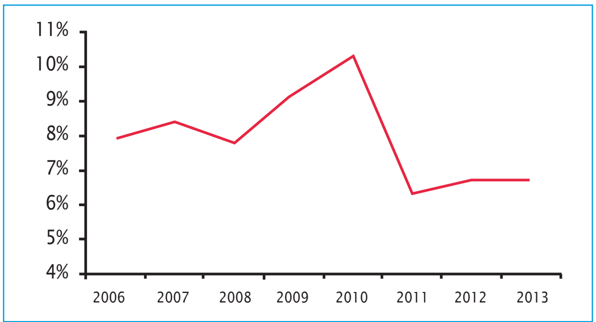


Source: Energy Regulation Board[7]

The country's economy grew at an average of 6.3 per cent between 2006 and 2013 (Figure 4) and the demand for electricity has been growing at an average of about 3 per cent per annum. This is mainly due to the increased economic activity in the country, especially in the agriculture, manufacturing and mining sectors, as well as general increased activity in the region. The country's growing economy has led to an increase in the demand for petroleum, coal and renewable energies in recent years.[4]

FIGURE 4

Annual economy growth in Zambia 2006-2013 (%)



Source: Central Statistics Office[4]

The electricity industry in Zambia is governed by the Electricity Act 1995 and the Electricity Amendment Act 2003. The overall responsibility for energy administration and policy formulation lies with the Ministry of Mines Energy and Water Development (MMEWD) while the Office for Promoting Private Power Investment (OPPPI) has the role of promoting private investment in the development of power projects. The Energy Regulation Board (ERB), formed through an Act of Parliament in 1995, is responsible for licensing generating plants, regulating transmission and distribution operations, regulating power tariffs (especially retail) and mediating any conflicts regarding these issues.

ZESCO is the state-owned power utility responsible for generation, transmission and distribution. In some rural areas, which ZESCO's national grids do not cover, small independent private power producers (IPPs) and non-governmental organisations (NGOs) are supplying electricity through isolated distribution networks with SHP or diesel power plants. With the electricity industry liberalized in 1995 in order to attract investment, several private companies now provide services including Copperbelt Energy Corporation, Lunsemfwa Hydro Power Company, Maamba Collieries Ltd and Zengamina.

The Rural Electrification Authority (REA) is a statutory body created under the MMEWD through the enactment of the Rural Electrification Act 2003. Its role is to re-establish the Rural Electrification Fund (REF) and to provide for matters connected with rural electrification.

TABLE 1

2014 approved tariffs in Zambia

Tariff type	Tariff (Zambian Kwacha (US$)/ kWh)
Residential (up to 100 kWh)	0.19 (0.0361)
Residential (101 and 300 kWh)	0.31 (0.0589)
Residential (above 300 kWh)	0.51 (0.0969)
Residential (pre-paid tariff)	0.35 (0.0665)
Commercial	0.31 (0.0589)
Social services	0.28 (0.0532)

Source: Energy Regulation Board[17]

Electricity tariffs were adjusted in 2014 in order to move towards economic rates that would eventually support re-investment in the sector. The current residential rates are 0.19-0.51 Zambian Kwacha (ZMK)/kWh and 0.31 ZMK per kWh (US$0.03 to US$0.09 per kWh and US$0.05 per kWh respectively) for commercial rates (Table 2).[16,17] The foreign currency exchange rate has a significant influence in the interpretation of the Zambian tariff. All tariff adjustments are subjected to public hearings and approved by the Energy Regulation Board in order to address varying economic and developmental requirements in the country.

Zambia has approximately 6,000 MW of undeveloped hydropower potential.[10] Despite vast renewable and non-renewable energy source in Zambia which could contribute to improve the attractiveness of the energy

TABLE 2

ZESCO owned SHP plants in Zambia (< 10 MW)

Plant name	Capacity (MW)
Chishimba HPP	6.00
Musonda HPP	5.00
Shiwangandu HPP	1.00
Total	**12.00**

Source: Energy Regulation Board[17]

sector and transfer the benefits for industrial expansion, employment creation and poverty reduction, few have been developed. The energy market structure and consumption shows that traditional wood fuels (biomass), such as firewood and charcoal sourced from natural woodlands and agricultural lands, dominate the energy market.[10,11]

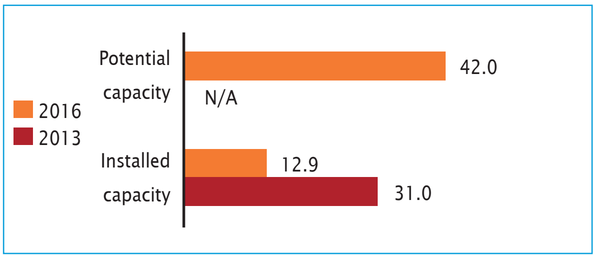
Small hydropower sector overview and potential

Zambia classifies small hydropower (SHP) plants as between 0.5 MW and 10 MW. Plants less than 0.5 MW are classified as micro-hydropower. Plants between 10 MW and 100 MW are classified as medium hydropower and installed capacities greater than 100 MW as large hydropower.

The total installed capacity for SHP plants below 10 MW is approximately 12.9 MW with an estimated potential capacity of, at least, an additional 29.1 MW.[9] This indicates that approximately 31 per cent of the country's SHP potential has been developed. In 2013, the potential capacity was unknown; though installed capacity was 31 MW (Figure 5).[9] This decrease in installed capacity of approximately 60 per cent is primarily due to several plants having recently been or are in the process of being upgraded above 10 MW. Hence, these plants are no longer technically classified as SHP.

FIGURE 5

SHP capacities 2013-2016 in Zambia (MW)



Sources: Zesco,[8,15,16] *WSHPDR 2013*[9]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

The SHP sector in Zambia is currently undergoing a transformation with the upgrading of existing plants and proposed plants in various stages of development. Currently, four SHP plants operated by ZESCO are being upgraded and connected to the grid: Lunzua has been upgraded from 0.75 MW to 14.8 MW; Chishimba is being upgraded from 6 MW to 10 MW; Lusiwasi is being replaced by new plants upstream and downstream with capacities of 12 MW and 86 MW; and Musonda is being upgraded from 5 MW to 10 MW. Tables 2 and 3 provide details of SHP plants in Zambia below 10 MW.

In recent years, private sector small-scale social and industrial developers have also managed to install some micro-hydropower systems with a total installed capacity of approximately 900 kW (Table 3).

In total, installed SHP capacity accounts for less than 1 per cent of the total hydropower capacity of the country. The total figure is also expected to increase by an additional 120 MW after the commissioning of the Itezhi-tezhi project.[8]

TABLE 3

Privately owned SHP plants in Zambia (kW)

Plant name	Capacity (kW)
Zengamina	**700.0**
Nyangombe	**73.0**
Sachibondu	**15.0**
Lwawu	**50.0**
Mutanda	**2.5**
Mporokoso	**5.0**
Mangango	**17.0**
Mayukwayukwa	**28.0**
Katibunga	**N/A**
Total	**890.5**

Source: Rural Electrification Authority[13]

TABLE 4

Planned SHP plants in Zambia (MW)

Plant name	Capacity (MW)	Status
Mumbuluma	8.0	Feasibility
Mujila	7.0	Feasibility
Namundela	4.8	Feasibility
Kalepela	4.0	Feasibility
West Lunga	2.5	Packaging
Zengamina	1.4	Packaging
Chanda	1.0	Feasibility
Kasanjiku	0.4	Tender
Total	**29.1**	

Sources: ZESCO LTD,[15] Rural Electrification Authority[13]

SHP potential in Zambia remains inaccurately recorded mainly due to the lack of a comprehensive and updated database specifically for SHP. Recently identified and investigated SHP sites in Zambia are recorded in Table 4. Based on these data, there is a SHP potential of at least 29.1 MW. Nonetheless, due to the lack of accurate data, this is likely to be a gross underestimate and the real figure is expected to be significantly higher.[15,13] The total estimated potential for hydropower (small and large) is more than 6,000 MW.[8]

Renewable energy policy

The policy framework governing all forms of renewable energy in Zambia is driven by the National Energy Policy (NEP). The current NEP, formulated in 2008, recognises the critical role played by renewable energy in poverty alleviation and national development. The key principles of the policy related to the national development plans of Zambia include the following:

- Development of appropriate technology and resources to enhance socio-economic development.
- Reflect current and future energy supply needs of the country and account for different energy needs of various consumers.
- Develop the human resources for effective implementation of energy programmes.
- Optimise energy efficiency at the production, transformation and consumption levels.
- Provide incentives to enhance the performance of the energy sector.
- Integrate energy development into national development interventions and strategies.
- Resource mobilization for development of the energy sector.
- Partner with the private sector, civil society and community groups.[11]

The NEP recognizes the significance of various sources of energy and the need to quantify the potential of renewable energy sources. While to date there are studies on potential capacity for solar and wind sources, studies on hydropower, biomass-gas, biomass-methane and geothermal energy potential have not progressed adequately.[11]

Legislation on small hydropower

The National Energy Policy (NEP) of 2008 encompasses a range of energy options, including hydropower. The policy measures relevant to SHP development adopted in the National Energy Policy include the following:

- Encourage the development of identified potential hydro sites.
- Move towards cost reflective tariffs.
- Adopting an open access transmission regime.
- Application of smart subsidy mechanisms.[11]

Barriers to small hydropower development

The Zambian SHP industry faces several challenges including the following:

- Information on large river basins such as the Zambezi, Kafue, and Luapula may be available but the small river basins lack the hydrological data necessary to adequately assess the potential energy.
- Lack of a comprehensive energy policy to deal with the requirements of private plants interfacing with the national grid, such as a feed-in tariff, has affected the process of private sector participation in SHP. Nonetheless, the participation of the private sector in the development of new small projects is vital for the development of rural districts.
- Suitable SHP potential is mainly located in remote areas and the cost of transporting electricity through the transmission system to the consumption centres of the country affects the profitability of projects.
- The tariff structure in Zambia is still not reflecting the real cost of investment. There is a need to address the structure of the tariff so that it can attract investment. It is common to see figures such as US$0.8 to US$0.12 per kWh in feasibility reports but the existing electricity tariff remains far less.
- Access to the capital markets for the general local private-sector investors remains a challenge to new entrants in 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.
- The challenges related to energy policy, feed-in tariffs, and cost reflective tariffs directly affect the ability to attract investment.
- The poor road network in rural areas makes SHP construction difficult and expensive.

1.1.14 Zimbabwe

Lasten Mika, Institute of Environmental Studies, the University of Zimbabwe; Nathan Stedman, International Center on Small Hydro Power (ICSHP)

Key facts

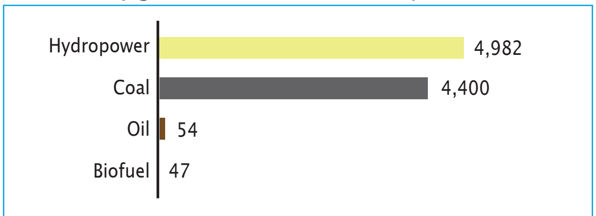
Population	13,061,239[1]
Area	390,757 km[2]
Climate	The climate is temperate to tropical with hot wet summers from November to April and cool dry winters from May to October. Temperatures can reach as high as 40°C in summers and as low as 5°C in winters.[2]
Topography	Zimbabwe has an average elevation of 1,500 m above sea level and almost all of it over 300 m. The highest elevation is in the Nyangani mountains to the north-east of the country at 2,592 m.[3]
Rain pattern	The highest falls are in the eastern highlands with annual rainfall of up to 1,000 mm. The high veld receives an annual average fall of above 500 mm. The Limpopo valley located in the south-eastern low-veld typically receives the lowest rainfall. Rainfalls below 400 mm are common.[2]
General dissipation of rivers and other water sources	The high veld is a central ridge forming the country's watershed, with streams flowing south-east to the Limpopo and Sabi Rivers and north-west into the Zambezi. Only the largest of the many rivers have a year-round flow of water.[2]

Electricity sector overview

Traditionally, the energy mix in Zimbabwe was dominated by thermal sources, chiefly coal and biomass (for heating and cooking). More recently, the Kariba dam and the installation of hydroelectric systems on existing dams has increased the share of hydropower.[4] In 2014, the installed electricity capacity in Zimbabwe was 2,045 MW, with 750 MW from hydropower.[15] Due to economic conditions, seasonal water flow and ageing systems, the average available capacity was far lower at 1,250 MW. This fell short of the 2,200 MW energy demand and was offset by imports.[4] Electricity production in 2013 reached 9,483 GWh, with more than 50 per cent from hydropower (Figure 1).[13]

FIGURE 1

Electricity generation in Zimbabwe by source (GWh)



Source: IEA[13]

The power sector in Zimbabwe is largely controlled by the Zimbabwe Electrical Supply Authority (ZESA) and its four subsidiary companies, namely the Zimbabwe Power Company (ZPC), the Zimbabwe Electricity Transmission and Distribution Company (ZETDC), ZESA Enterprises and Powertel. These entities own and operate the five major power stations in the country (Table 1). Meanwhile, the Electricity Act of 2002 created openings for independent power producers (IPP) to enter the industry, mostly in the small, mini- and micro-systems arena.[4]

As of the last quarter of 2015, 18 IPPs had licences issued by ZESA, 7 of which had systems installed and were supplying 103 MW to the national grid. The remaining 11 projects are estimated to increase combined capacity to 5,365 MW within a three year period.[7]

TABLE 1

Installed capacity and availability in Zimbabwe (MW)

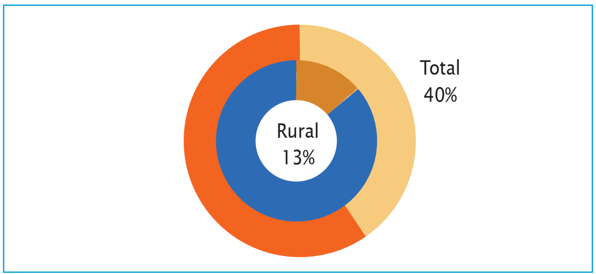
Site name	Type of station	Installed capacity (MW)	Available capacity (MW)
Kariba	Hydro	750	650-750
Hwange	Thermal	920	500-700
Harare	Thermal	100	30
Munyati	Thermal	90	30
Bulawayo	Thermal	90	30
Total		**1,950**	**1,240-1,540**

Sources: EUEI-PDF,[4] ZPC[8]

The electrification rate during 2015 was estimated at 40 per cent, with urban area household access at 80 per cent and rural areas at 14 per cent. The estimates were approximated by both ZESA and the Africa Energy

FIGURE 2

Electrification rate in Zimbabwe



Source: Zimbabwe Electricity Supply Authority[8]

Outlook and were not exact as compiling the statistics has been problematic (Figure 2).[8,9]

As of 2015, the Zimbabwe Energy Regulatory Authority (ZERA) was finalizing a study on feed-in tariffs (FIT) for renewable energy sources which would include standardized power purchase agreements.[4]

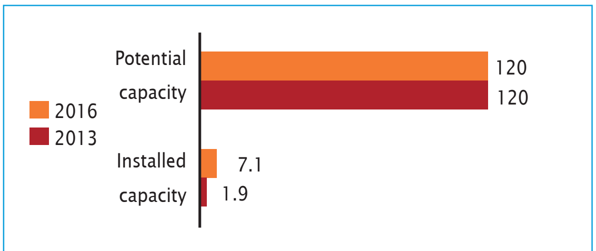
Small hydropower sector overview and potential

In Zimbabwe, the definition of small hydropower (SHP) is installed capacity between 1 MW and 10 MW. Installed capacity SHP in Zimbabwe is at least 7.1 MW and the potential capacity is estimated at 120 MW.[4] From 2013 to 2016, the installed capacity has increased from 1.92 MW to 7.1 MW while the potential capacity remained unchanged (Figure 3).[4,10]

Registered IPPs are currently producing and supplying electricity throughout the country. In the Eastern Highlands, independent power producers have installed or are in the process of installing more than 2.2 MW of mini-hydropower generating units feeding into the national grid. While other projects are currently being commissioned or constructed, the SHP sector is chiefly operated by two IPPs, namely Nyangani Renewable Energy Company and Rusitu Power Company (Table 2).[4]

FIGURE 3

SHP capacities 2013-2016 in Zimbabwe (MW)



Sources: EUEI-PDF,[4] *WSHPDR 2013*[10]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

The non-governmental organizations Practical Action and OXFAM have been promoting small-scale micro-hydro systems in the Eastern Highlands. Hydropower generation close to 350 kW of generating capacity has been installed and operated in the local communities. Many of these isolated micro-systems are focused on schools, hospitals and clinics. Currently, at least 11 mini-grids are operational in the country, with Chipendeke and Nyafaru demonstrating the highest levels of sustainability (Table 3).[4]

TABLE 2

SHP in Zimbabwe

Site name	Installed capacity (MW)	Expected capacity* (MW)
Duru	2.2	—
Nyamingura	1.1	—
Pungwe A	2.75	—
Pungwe B*	—	15*
Pungwe C*	—	2.72*
Rusitu	0.75	—
Total	6.8	24.52*

Source: EUEI-PDF[4]
Note: Micro SHP is not included in this table (Table 3). An asterisk (*) indicates plant is under construction. Pungwe B is included, as its installed capacity may be lower upon completion.

TABLE 3

Micro-hydropower in Zimbabwe (kW)

Site name	Status	Installed capacity (kW)
Chipendeke	Operational	27
Claremont	Non-operational	30
Dazi	Operational	20
Himalaya	Commissioning	80
Hlabiso	Operational	30
Ngarura	Operational	30
Nyafaru	Operational	20
Nyamwanga	Commissioning	30
Nyamarimbira	Non-operational	30
Svinurai	Non-operational	30
Chitofu, Rusape	Non-operational	20
Total	—	**347**

Source: EUEI-PDF[4]
Note: This list is incomplete. As much as 2.2 MW of mini- / micro-hydro may have been installed or are in the process of installation.

The National Energy Policy (NEP) and the Rural Electrification Act mandate the Rural Electrification Agency (REA) to coordinate the Rural Electrification Fund (REF) to facilitate the rapid and equitable electrification of rural areas using grid and off-grid technologies.[12] While the REA is required to fund projects, there are no clear guidelines for such support. Without the guidelines, operators have passed the burden to the end users via tariffs.[4,14]

There has been stagnation in new power infrastructure development because of a lack of financing, non-viable energy pricing and a slowdown in adoption of new and renewable sources of energy. Despite the lack of financing, projects with a potential capacity of 120 MW have been identified countrywide. Sites are on dams and run-of-river.[4]

Renewable energy policy

The National Energy Policy (NEP) recognizes the policy gap with respect to renewable energy and proposes to have a Renewable Energy Policy and law that will facilitate the introduction of sector specific incentives for the wider adoption of renewable energy technologies. This is also meant to facilitate rapid acceleration of the adopted goals of Sustainable Energy for All (SE4ALL) by 2030. Zimbabwe opted in to the SE4ALL initiative under the United Nations Development Programme (UNDP) that recognizes energy access as the critical lever in ending poverty. However, sector stakeholders do not think this will be achievable because of the current state of the economic environment which is stifling energy generation expansion.[4,14]

Barriers to small hydropower development

Despite the removal of legal barriers for private sector investment in the power sector (with the exception of cogeneration) under the Electricity Act of 2002, private sector investment in power has been minimal. ZERA has licensed projects with a combined capacity of more than 5,000 MW but only 7 MW have been successfully implemented for supplying the main grid or isolated grids. This demonstrates the Government's commitment to pursuing a scaling up of renewable energy generation with private sector participation but it also indicates the presence of the following barriers to implementation:[4]

- The absence of a renewable energy (RE) policy; no RE targets or clear incentive and institutional framework for renewable energy investments;
- The absence of a rural energy master plan;
- Lack of awareness of renewable energy resource availability and competitiveness;
- No standards for RE technologies and mini-grids;
- No clear guidelines for the responsibilities for grid impact studies when the mini-grid interfaces with the main grid;
- No clear economic incentives for RE development;
- Environmental Impact Assessment and water charges applied without due consideration of system size or consumptive/non-consumptive water use;
- Poor financial sustainability of existing pilot mini-grids;
- No standardized tariff methodology and project agreements for small power projects and mini-grids;
- Problems with data collection.

1.2 Middle Africa

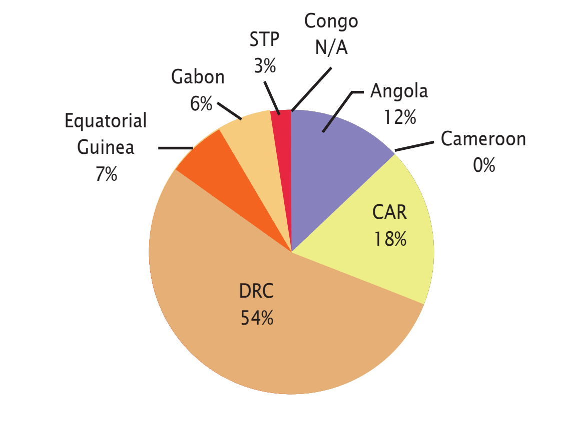
Phillip Stovold, Citrus Partners LLP

Introduction to the region

The geographic sub-region of Central Africa (or Middle Africa) is the core region of the African continent. According to the United Nations (UN), this sub-region contains nine countries, including Angola, Chad, Congo, the Democratic Republic of the Congo (DRC), the Central African Republic (CAR), Cameroon, Equatorial Guinea, Gabon and the islands of Sao Tome and Principe (STP).[5] This report will cover Angola, Cameroon, Congo, the Democratic Republic of the Congo, the Central African Republic, Equatorial Guinea, Gabon and Sao Tome and Principe. Equatorial Guinea, Gabon and Congo were not covered in previous editions. The overview of countries of Middle Africa is given in Table 1.

FIGURE 1

Share of regional installed capacity of SHP by country



Source: *WSHPDR 2016*[3]

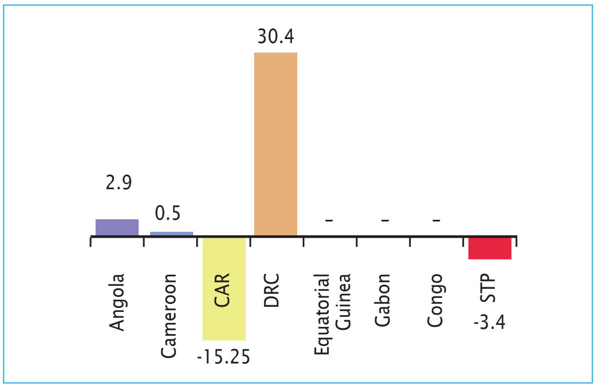
Middle Africa holds 40 per cent of the continent's hydropower resources. In 2013, the sub-region generated 14,614 GWh out of a technically feasible 1,584,670 GWh per year. However, this was only 3 per cent of the total potential for this source of renewable energy (RE).[7]

The hydropower resources of Middle Africa are enough to supply the entire continent, and progress is being made in developing the larger scale hydropower resources in several countries. Nevertheless, to date, all the countries in the region have very low electrification rates. These rates are significantly worse in rural areas. Additionally, poor transmission and distribution networks are in dire need of maintenance.

Climate and rainfall patterns vary considerably across Middle Africa. Rainfall is relatively intense and reliable in the central equatorial and coastal areas but it diminishes and becomes variable in the most northern and southern regions. In the centre of the Congo basin, along the coast of Gabon and on the mountain summits bordering the Western Rift Valley, the annual rainfall exceeds 2,000 mm,

FIGURE 2

Net change in SHP (MW) from 2013 to 2016 for Middle Africa



Sources: *WSHPDR 2016*,[3] *WSHPDR 2013*
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting; CAR decrease is due to the exclusion of Baoli 3 and several micro/pico sites, for more information see country report.
Note: A dash (-) indicates the country was not covered in the previous report and a comparison cannot be made.

while on the coastal region of Cameroon it can reach up to 3,850 mm per year. In contrast to this tropical setting, the semi-arid zone of Chad receives an average annual rainfall of 500 mm and suffers from severe periodic droughts.[7]

The topography of Middle Africa is characterized by wide plateaus of varying relief that in turn define the hydrology of the region.[4] The Congo River basin, second only to the Amazon in regards to its rate of water flow, is the largest river basin in Africa and covers an area of 3.7 million km^2. The Congo River has the largest water discharge of any river in Africa, followed by the Zambezi, the Niger and the Nile. Some fragments of northern Middle Africa are situated within the Chad River basin (northern Central African Republic) and the Nile River basin (eastern Rwanda and northern Burundi).

Small hydropower definition

Most of the countries in the region define small hydropower (SHP) as plants with a capacity of up to 10 MW, whereas others lack an official definition of SHP. For the countries that lack an official definition, this report will use the definition of 10 MW and below (Table 3).

Regional SHP overview and renewable energy policy

Angola is leading the way in the region, with ambitious and financed plans to develop its hydropower resources, estimated to be 150 TWh/year, and supported by a World

TABLE 1

Overview of countries in Middle Africa (+% change from 2013)

Country	Total population (million)	Rural population (%)	National electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Angola	24.38 (-)	55.9 (-14.1pp)	37 (+10.8pp)	2,210 (+70%)	5,613 (+35%)	1,528 (+70%)*	3,141 (0%)
Cameroon	22.77 (+13%)	45.6 (-2.3pp)	56 (+7.3pp)	1,536 (+88%)	6,302 (11%)	1,152 (56%)*	4,425 (+5%)
Central African Republic	4.8 (-5%)	60 (-1pp)	3 (0pp)	40 (-13%)	150 (-6%)	29 (+18%)	120 (-8%)
Congo	4.6	34	41	576	N/A	209	1,000
Democratic Republic of the Congo	74.8 (+1.6%)	57.5 (-8.2pp)	9 (-2.1pp)	2,443 (0%)	N/A	2,416.9 (+1%)	N/A
Equatorial Guinea	0.85	60.1	66	303	850	127	N/A
Gabon	1.7	12.8	89	415	2,390	170	900
Sao Tome and Principe	0.19 (+4%)	34.9 (-3.1pp)	60 (0pp)	32.7 (+104%)	86 (+110%)	2.6 (-71%)	10 (0%)
Total	**133.8**	—	—	**7,554.7**	**24,155.5**	**5,634.5**	**9,596**

Source: Various[1,2,3,4]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.
Note: An asterisk (*) indicates data taken from the country report in *WSHPDR 2013* and not the 2013 regional summary.

TABLE 2

Classification of small hydropower in Middle Africa

Country	Small (MW)
Angola	Up to 10
Cameroon	Up to 10
Central African Republic	Up to 10
Congo	—
Democratic Republic of the Congo	Up to 10
Equatorial Guinea	—
Gabon	—
Sao Tome and Principe	Up to 10

Source: *WSHPDR 2016*[4]

TABLE 3

Installed and potential small hydropower capacity in Middle Africa (+% change from 2013)

	Potential (MW)	Installed capacity (MW)
Angola	861 (+543%)	12.9 (+29%)
Cameroon	615 (-)	0.5 (-)
Central African Republic	41 (+0%)	18.95 (-45%)
Congo	50	N/A
Democratic Republic of the Congo	100.9 (+0%)	56 (+119%)
Equatorial Guinea	N/A	7
Gabon	N/A	6
Sao Tome and Principe	63.6 (+112%)	2.6 (-57%)
Total	**1,681.5**	**112.45**

Sources: *WSHPDR 2016*,[3] *WSHPDR 2013*[4]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Bank MIGA facility. The Cambambe 1 and 2 hydropower plants with 700 MW capacity supplied by Voith Hydro are projected to become operational in 2016. This is part of a US$23.4 billion plan to boost generation capacity fivefold to 9,000 MW by 2025.[9] The government has committed to several large-scale hydropower projects, starting with the 2,100 MW hydropower plant (HPP) Laúca. Further projects are in process along the middle Kwanza section, including HPP Caculo Cabaça (2,100 MW), HPP Nhangue (450 MW), HPP Zenzo I (450 MW), HPP Zenzo II (120 MW), HPP Túmulo do Caçador (450 MW) and HPP Luime (330 MW). In addition to this, other hydropower projects have been identified and are under development, including the HPP Chiumbe-Dala (26 MW), HPP Chicapa II (42 MW), HPP Lupasso (26 MW), HPP Matala (40 MW), HPP Lomaum (65 MW) and small HPP Luachimo II (10 MW).[10] There is also a project being co-developed with Namibia in the Baynes Mountains on the Cunene (500-600 MW).

Cameroon has an estimated 115 TWh of hydropower resources.[11] A 120 MW hydropower station is being developed with a dam at Lom Pangar with US$132 million aid from the World Bank and the African Development Bank. Regularizing the seasonal flow of the Sagana River system with the dam will also increase output further downstream at the Edea and Song Loulou hydropower stations by 40 per cent (70 MW) by 2016. China Exim Bank has financed the 200 MW Memve'ele hydropower station, currently being built by Sino Hydro and due for completion in 2017. There are detailed studies of several hundred SHP sites with estimates on seasonal power capacities and locations. Additionally, Kaboni Energy is developing a series of large- and small-scale hydropower plants (60 MW) in the south-west of the country, while Électricité de France signed an agreement in 2015 to build a 420 MW hydroelectric dam at Nachtigal Falls. The legislative regime was improved significantly with the 2011 Electricity Law but confusion remains on its implementation. For example, the Ministry of Water Resources and Energy (MINEE) still controls project development allocation, even though this control could now rest with the regulator, the Electricity Sector Regulatory Agency.

Though the new law provides for a simple authorization procedure to develop and install SHP projects in rural areas, securing the land and water resource rights through the local, district, and central governments, makes the process very complicated. As a result, the MINEE is also developing additional plans to support the development of Independent Power Producers in regions not serviced by the transmission network.

The Democratic Republic of the Congo (DRC) has experienced relative stability since the last elections in 2011, though its institutions remain weak and the political situation is fragile. With elections due in 2016 and regional elections under way, the country is tense and development is difficult. The country remains second to last on the Human Development Index and many parts of the country are unsafe.[12] There are three major projects underway, with a particular focus on the Inga hydropower station refurbishment and development, that is, to develop a plan for a 44,000 MW mega dam. More than 100 small-scale hydropower sites have been identified, although there has not been a specific legislative process for their development. In a country dominated by large-scale hydropower projects, and one that plans to export electricity despite having a very low internal electrification rate, the need to provide for small-scale hydropower development is not yet seen as a priority. This is despite the fact that in many rural areas, this would be the best electrification option. There have been some small-scale hydropower projects developed, although this is often due to commercial operators developing systems for their own use. One of the major issues in the DRC can be seen with the tariffs, which are set too low for viable private sector development of small-scale hydropower projects. The DRC is currently installing major transmission networks, and working on developing its legislative and policy frameworks.

All but one of the smaller countries in the region still need to put in place the supportive legislative and policy frameworks required to encourage private sector development of their small-scale hydropower resources. The Central African Republic has identified multiple sites across the country, but remains a conflict area. The former Prime Minister Faustin Archange Touadera won the country's presidential election in February 2016 and there is optimism that the war-ravaged country may continue to recover.

Equatorial Guinea has 6,100 MW of hydropower potential and two large-scale hydropower projects under development. However, without government transparency and a regulatory framework to underpin commercial small-scale hydropower development investments, the sector is likely to remain untouched.

Gabon has an estimated 6,000 MW of hydropower potential, some of which are being developed. For example, in 2013, the Sino Hydro Corporation completed the 160 MW Grand Poubara hydroelectric plant. The Ministry of Energy has also researched and identified 60 potential hydropower sites, which allowed for several smaller scale hydropower plants to begin construction. Hydropower development in Gabon remains a state-run enterprise.

Congo has considerable scope for SHP development. However, the regulatory and permitting process is not clearly defined, and the country can already meet its current electricity requirements through the large-scale projects proposed to date. While there are several plans for SHP development, low consumer tariffs make development less financially feasible. Small scale hydropower development is only commercially viable in remote, off grid locations where the substitution cost for electricity is estimated to be CFA Franc 332/KWh (approximately US$0.55/KWh).[3]

Sao Tome and Principe are the exception which do have supportive legislation. In December 2014, the country updated a law that defines how the electricity sector should operate. The islands have low electrification rates and a dilapidated transmission network, though investments have been made in recent years. There are 34 exploitable sites across the two islands with an estimated capacity of 63.6 MW.[13]

Barriers to small hydropower development

A dominant issue in the region is the lack of a transparent, complete and accessible regulatory framework that encourages and facilitates the early stage risk of finance investment for small-scale hydropower development. For example, Cameroon has a good legislative and policy framework, but lacks the regulations required for implementation. Countries often have investment inhibitors, such as automatic rights to land confiscation, which make investment impossible without complicated insurance guarantees. Progress has been made, but the region continues to be difficult for the development of SHP projects, as these types of projects do not usually have the financial resources required to overcome the significant investment hurdles. Moreover, low retail prices of electricity do not allow for the reimbursement of costs. It should be noted that all these countries experience governance and corruption problems, making small-scale private hydropower project development difficult in the region.[14]

1.2.1 Angola

Vladimir Russo and Sendi Baptista, Holísticos, Lda.

Key facts

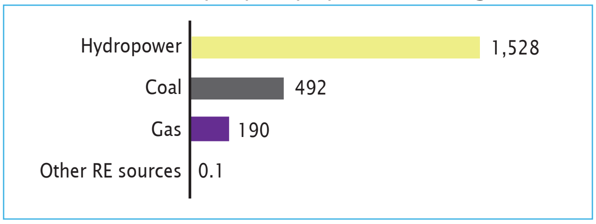
Population	24,383,301[1]
Area	1,246,700 km[2]
Climate	Tropical weather with a rainy season in the warmer period (September – May) and dry season in the cooler period (June – August). Due to its geographical situation, weather in Angola can be divided into two distinct climatic regions, the coast and the interior. The average temperature ranges from 27°C to 17°C.[2]
Topography	Topographically, Angola consists of a coastal plain and broad tablelands above 1,000 m in altitude, a high plateau in the centre and south ranges of up to 2,400 m. The highest point in Angola is Mount Moco, at 2,620 m in the Huambo province.[3] There are 47 main hydrographical basins and 30 sub-basins.[4]
Rain pattern	Hot summer months are very dry, with almost no rainfall (June – August). The wet season (October – April) has between 100-250 mm of rainfall per month. The wettest region is the north-east, and the total rainfall decreases southwards and towards the western coast.[2]
General dissipation of rivers and other water sources	Most of the rivers rise in the central mountains. Of the many rivers that drain to the Atlantic Ocean, the Cuanza and Cunene are the most important. Other major streams include the Kuango River, which drains north to the Congo River system, and the Kuandoand and Cubango Rivers, both of which generally drain south-east to the Okavango Delta in Botswana. Angola has no sizable lakes.

Electricity sector overview

In 2015, the installed capacity in Angola was 2,210 MW. Electricity generation was 5,613 GWh in 2014.[16] Of the installed capacity, roughly 69 per cent is from hydropower, while coal-fired plants represent 22.3 per cent and combined cycle gas turbines represent 8.6 per cent. The remainder (0.1 per cent) consists of other renewable sources (Figure 1).[16] According to the World Bank, the electrification rate in 2012 was 37 per cent.

FIGURE 1

Installed electricity capacity by source in Angola (MW)



Sources: SE4ALL,[15] IJHD[16]

The national energy sector in Angola, particularly the electricity component, was damaged by the civil war. It was only after 2002 that the country met the necessary and sufficient conditions for its restructure, organization and operation. Internal deficits are large, thus, to ensure the reform and modernization of this sector, the Ministry of Energy and Water published the Master Plan for Reform in October 2004. This document outlines the evolution of the electricity sector since 1996 and their prospects by 2016, based on previous studies and seminars.[5]

In addition, the Electricity Sector Transformation Program (PTSE) proposes that power sector reform should evolve through four different phases. The Preparatory Phase (Phase 1), which involves a diagnostic and design study, was completed with the establishment of three new power entities for electricity: generation, transmission and distribution. It was also completed with the strengthening of the Regulating Institute of the Electrical Sector (IRSE). The Preparatory Phase will also lead to a review of tariffs and subsidies, including stabilization and tariff adjustments toward cost reflective value. Phase 2, which is expected to start in 2018 and continue until 2021, introduces the concept of sector-wide operational efficiency with tariffs approaching the cost of production, and includes the incentivised participation of the private sector in renewable energy (RE) in rural areas (in the form of feed-in tariffs). Partial liberalisation of distribution systems and the energy sector, including full participation of independent power producers (IPPs) and the improvement of the energy mix, is expected to be concluded by 2017 as part of Phase 3 of the PTSE.[6]

Presidential Decree No. 256/11, National Policy and Strategy for Energy Security established a set of objectives for the electricity sector for 2025 and reinforced the

TABLE 1

Hydropower and thermal installed/expected capacity (MW)

	2009		2010		2011		2018	
	Hydro	Thermal	Hydro	Thermal	Hydro	Thermal	Hydro	Thermal
North	610	187	610	389	610	389	3,385	1,229
Centre	11	90	14	126	74	126	163	126
South	27	42	27	42	27	42	316	100
Subtotal	648	319	651	557	711	557	3,864	1,455
Total		**967**		**1,208**		**1,268**		**5,319**

Source: Electric Sector Transformation Program[6]

importance of electricity to the country. These goals included, amongst others, increasing the electrification rate from 30 per cent to 60 per cent, quadrupling generation capacity from the current 2.0 GW to 9.5 GW in 2025, extending more than 2,500 km of lines and substations in the transmission grid, establishing international interconnections, rehabilitating distribution networks and adding more than 1.5 million consumers.

According to the Centre of Studies and Scientific Research, the installed capacity in the north, central and southern systems was split between thermal and hydro production from 2009 to 2011. The expected capacity for 2018 is presented in Table 1.[5] There are three main transmission systems in the country: North, Central and South, with the remaining areas currently on isolated systems.[15] While it is currently a challenge facing the sector, there is a plan to interconnect the three independent grids by 2025.[7] The service capacity (peak demand), considering maximum supply from all producers in operation at the end of 2011, is shown in Table 2.

TABLE 2

Available electricity capacity (GW)

System	2009	2010	2011
North	797	999	999
Centre	101	140	200
South	69	69	69
Total	**967**	**1,208**	**1,268**

Source: Angola Energy Report (2011)[5]

Actual demand is very significant and requires a large increase in the country's production capacity. With the implementation of actual projects, it is expected that the peak demand in 2020 should be around 5,000 MW.[5] The National Electricity Production Company (PRODEL-E.P)[9] is currently responsible for 20 per cent of production in the country and is already operating all lines of transmission. The Office for the Management of the Middle Kwanza manages the largest production centre of the country, Capanda, until all public production assets of the country are passed to PRODEL (as planned). The Angolan electrical system is not part of the Electricity Exchange SADC SAPP.[5]

Despite robust growth in electricity production from 2007 to 2014, on average, the sector still constituted less than 1 per cent of the country's GDP.[10] The electricity sector in Angola currently has one of the lowest rates in Southern and Eastern Africa. With a high rate of transmission losses and distribution, efficiency is also one of the lowest in the region. Cost recovery in the sector was estimated just over 20 per cent in 2005. Consequently, 80 per cent of the cost is remitted via government subsidies.[5]

The IRSE is responsible for regulating the energy sector in Angola. It was established by Decree No. 4/02 on 12 March 2002 and plays the role of the regulator of the electricity sector, including the regulation of production, transport, distribution and sale of electricity in the Public Electricity System (SEP). It also regulates the commercial relationship between these different systems. The market prices for electricity are regulated by Presidential Decree No. 4/11 on 6 January 2011, which provides the basis for the calculation of the electricity tariffs.[11] The design principles of the newly established model intend to strengthen the regulator's (IRSE) role, to develop a competitive process for both public and private generation and to establish an Independent Transmission Operation, which will also act as a single buyer for all electricity generated in the SEP.[11]

Small hydropower sector overview and potential

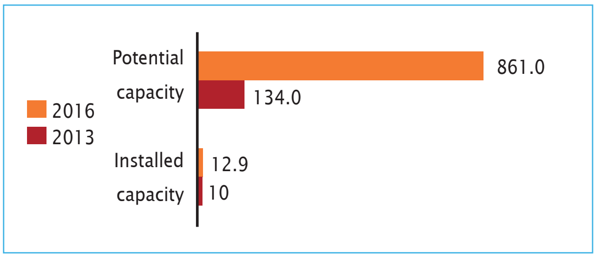
The definition of small hydropower (SHP) in Angola is up to 10 MW. Installed capacity of SHP in Angola is 12.92 MW while the potential capacity is estimated to be 861 MW, indicating that approximately 1 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased slightly while potential capacity increased by 727 MW.[15]

Angola has enormous hydropower potential. Hydropower currently provides 69 per cent of the country's electricity (Figure 1). However, facilities were destroyed in the civil war and the government has not succeeded in keeping supply in line with expanding demand. The technical hydropower potential is around 80 TWh/year and the economically available hydropower potential is 72 TWh/

year (18 GW).[12] SHP potential is currently being assembled into the Atlas of the Hydropower Resource. The study, conducted by the Ministry of Energy and Water, has identified 100 sites to be exploited, with a total potential capacity of 861 MW.[15]

FIGURE 2

Small hydropower capacities 2013-2016 in Angola (MW)



Sources: *WSHPDR 2013*,[12] SE4ALL,[15] INRH[17]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

TABLE 3

SHP installed capacity in Angola (MW)

SHP site	Installed capacity (MW)	Upgradable to (MW)
Cunje I	1.62	10
Luachimo	8.40	32
Luquixe I	0.90	—
Luquixe II	2.00	—

Sources: SE4ALL,[15] INRH[17]

The hydropower potential of Angola has five strands: Atlantic (41.1 per cent), Congo/Zaire (21.6 per cent), Etosha (3.8 per cent), Cubango/Cuito (11.9 per cent) and Indica (18.6 per cent).[4]

Renewable energy policy

Angola has an evident potential to use RE, particularly from water, solar, wind and biomass. Motivated by the country's low electrification rate, in 2009, the government invested in RE technologies to meet the electricity needs in rural areas. Using photovoltaic solar energy, 47 localities will be electrified mainly in Bié, Moxico, KuandoKubango and Malanje provinces. In terms of wind energy, the construction of a wind farm of 100 MW in Tômbwa is expected to support the development of the fishing industry in the Namibe province.[14]

Barriers to small hydropower development

The main barriers for SHP development in Angola include:

- Limited long-term financing models and private investors to provide RE to customers at affordable prices;
- Limited access to appropriate technologies in the mini, micro and pico hydro categories;
- Limited infrastructure for manufacturing, installation and operation including maintenance of SHP plants.

1.2.2 Cameroon

Fombong Matty Fru, Rural World Resources International

Key facts

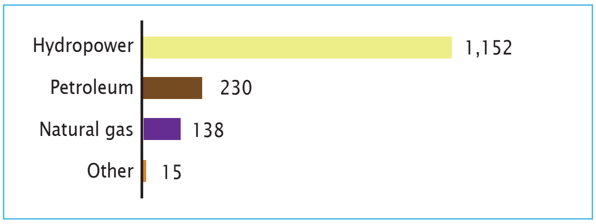
Population	22,773,014[1]
Area	475,650 km[2]
Climate	Climate varies with the terrain. It is tropical along coast to semi-arid and hot in north. July is the coldest month, with an average temperature of 22°C while the hottest month is February, averaging 25°C.
Topography	The southern forests are of dense vegetation, with abundant rainfall resulting in a vast river network. The high plateaus of the west form an area of rich volcanic soil, which favours agriculture. Cattle breeding predominate the savannah and steppe in the north. In the south-west, the maritime border with the Atlantic Ocean is about 420 km. The highest peak is Mount Cameroon at 4,070 m.[2]
Rain pattern	Annual rainfall is highest in the coastal and mountainous regions. The wet season (May – November) comes when the West African monsoon wind blows from the south-west, bringing moist air from the ocean. The wettest regions receive more than 400 mm per month of rainfall, but the semi-arid northern regions receive less than 100 mm per month. The southern plateau region has two shorter rainy seasons (May – June and October – November).[2]
General dissipation of rivers and other water sources	The Sanaga River, the country's longest at 920 km, and its river basin, cover roughly 140,000 km^2, making up 30 per cent of the territory. The Sanaga and other rivers, namely Nyong, Ntem, Mungo and the Wouri, all flow to the Atlantic. The Logone and its tributaries drain to the north, to Lake Chad. The Benue and its tributaries (the Faro, the Mandara, the Alantika and Mayo Kebi) drain northward to the Niger River.[2]

Electricity sector overview

The country has an installed capacity estimated at approximately 1,536 MW, with electricity generation of 6,302 GWh.[3] From overall installed capacity, hydropower contributes to 75 per cent (1,152 MW), petroleum 15 per cent (230 MW), natural gas 9 per cent (138 MW), and other generators contribute 1 per cent (15 MW) (Figure 1).

FIGURE 1

Installed electricity capacity in Cameroon (MW)



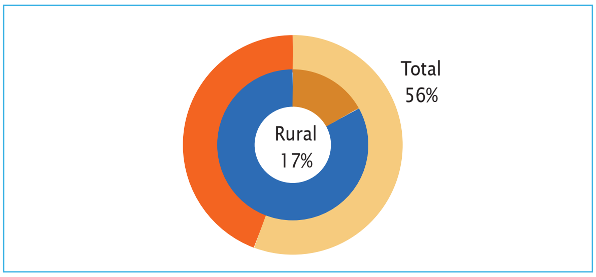
Source: IEA[3]

The hydroelectric power potential of Cameroon is second only to the Democratic Republic of the Congo in Africa, estimated to be around 23,000 MW. However, the current installed capacity represents only about 4 per cent of this technically feasible and exploitable supply. The country is currently building small- and large-scale hydro and thermal plants to contribute to electricity access goal, which is to reach 4,000 MW by the end of 2030.[4]

As of 2012, the national electrification rate was 56 per cent, with 88 per cent access in urban areas and nearly 17 per cent in rural areas (Figure 2).[9]

FIGURE 2

Electrification rate in Cameroon



Source: IEA[9]

Cameroon relies on approximately 30 ageing diesel power stations as back-up facilities, the largest of which are located in Garoua (20.0 MW), Douala (15.4 MW), and Yaoundé (10.8 MW). The production of oil is around 24.5 million barrels per year. The country's potential to produce electricity from biomass residues is estimated at 1,072 GWh. Proven natural gas resources are estimated at 157 billion m^3, with a potential of over 550 billion m^3. The amount of solar radiation in Cameroon ranges from 4.5 kWh/m^2 per day in the south to 5.74 kWh/m^2 per day in the north.[4]

The adoption of an electricity law in 1998 followed by a complementary electricity decree in 2000 led to the liberalization and privatization of the state-owned power utility with a 20-year concession in 2001. The state-owned power utility SONEL was privatized and purchased by the American company AES Sirocco in 2001, to become AES Sonel. This was later acquired by the British private equity firm Actis (56 per cent is held by Actis and 44 per cent is held by the Cameroon State) and renamed the Energy of Cameroon (ENEO Cameroun S.A.) in 2014. This entity was granted a monopoly over transmission and distribution throughout its concession area in Cameroon, along with the right to own up to 1,000 MW of installed capacity. ENEO operates with three distinct grids:

- The Southern Interconnected Grid, a 225 kV network connecting the major hydropower stations to the aluminium industry and Yaoundé and Douala, the main consumption areas;
- The Northern Interconnected Grid, a 110 kV and 90 kV structure dispatching the power generated by Lagdo power station, sufficient enough to cover the region's modest demand;
- The Eastern Interconnected Grid, a low-voltage distribution grid of 30 kV.

The main bodies in the power sector in Cameroon are: the Ministry of Energy and Water, responsible for implementing government action in the energy sector and overseeing energy sector activities; the Rural Electrification Agency (AER), responsible for promoting and implementing rural electrification in Cameroon and managing the Rural Energy Fund; the Electric Sector Regulation Agency (ARSEL), responsible for regulating the electricity sector as well as setting electricity rates and determining electrical standards; the Electricity Development Corporation (EDC), a state company that develops the electricity sector including all hydroelectric projects in the country, and ENEO, responsible for the transmission and distribution of electricity. The Electricity Law No. 2011/022, 14 December 2011 introduced additional bodies that are yet to be operational as an electricity sector development fund.[13]

The second electricity concession agreement signed between the Government of Cameroon and the Energy of Cameroon, ENEO, has redefined the roles of players in the production and distribution of electricity in the country.

This second amendment brings changes relating to the rehabilitation of the Song Loulou dam, specifically regarding the quality of services and connection plan. It states that the Song Loulou hydroelectric dam will be handed over to the Electricity Development Corporation after rehabilitation. The deal also provides that a new public corporation charged with the transmission of electricity in Cameroon will be established to rehabilitate and manage the dilapidating electricity transmission lines.

Prior to the agreement, the ENEO enjoyed a monopoly in electricity production and distribution, giving ENEO the mandate to adjust electricity prices. However, one of the major reforms enunciated in the agreement is the introduction of private electricity producers, thereby eliminating the monopoly in electricity production and distribution in Cameroon. Nonetheless, the redistribution of roles will not affect the electricity production capacity of electricity from the different dams in the country. The Song Loulou and Lom Panger dams will boost the national network with some 170 MW of electricity. However, this does not meet the projected 400 MW of energy.

The insufficiency is due to the suspended construction of the Kribi gas plant, which was meant to inject some 160 MW into the network. Also, the energy generated from Memve'ele and Mekin, which will increase the country's electricity potential to 1,200 MW, is far less than the envisioned 3,000 MW needed to meet the energy needs of Cameroon. The revision of the contract with the ENEO comes at a time when consumers have been decrying the quality of services provided by the company. Constant and unannounced power cuts, over-billing and the lack of maintenance of meters are some of the problems consumers have pointed out. The amendments, according to expectations, should influence the quality of services rendered by the ENEO and pave the way for competition in the electricity sector.

The administration in charge of electricity defines the tariffs, often with ARSEL providing advice. The tariffs are reviewed every five years by the ARSEL, who ensures that all changes must allow the operator normal returns in normal conditions of activity. Tariffs are also reviewed in the event that any material changes substantially affect the economic, financial and technical environment in which the contracts had been granted.[13]

There is one tariff system that is dependent whether the source of electricity is provided from gas, diesel or hydropower sources. For home use, electricity costs are approximately US$0.1/kW, and for industrial applications it is slightly less.

More specifically, the principal missions of the ARSEL are to:

- Monitor the sector's activity;
- Monitor the sector's financial equilibrium and approve tariffs;
- Examine concession licence applications;
- Authorize electricity generating and distribution in rural areas;
- Protect consumers;
- Promote competition and facilitate private sector involvement in the sector.

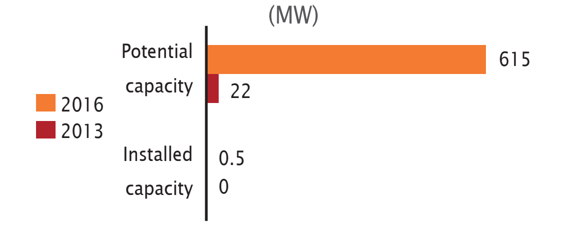
The AER is responsible for formulating policy and recommendations for rural electrification for the Ministry of Energy, as well as producing management schemes for rural communities in relation to electricity access.[13]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Cameroon is up to 10 MW. As of May 2016, installed capacity of SHP was estimated at 0.5 MW (Figure 3).[11,12]

FIGURE 3

Small hydropower capacities 2013-2016 in Cameroon (MW)



Sources: *WSHPDR 2013*,[5] FAO,[10] Africa-EU Energy Partnership,[11] ARSEL[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Local non-governmental organizations such as Action for Equitable, Integrated and Sustainable Development, have helped villages install pico hydro systems, often with locally made Pelton turbines, such as a 20 kW unit in Tchouadeng. However, comprehensive and accurate data on total installed capacity is not currently available.[8,11]

Electrification programs are based on large hydropower development and extension of the national grid. The 2.7 MW Gassona falls (ERD Rumpi project) is under construction and a total of 60 MW of SHP capacity is at the planning stage in south and south-west regions.[6] The country's SHP potential is estimated to be 615 MW.[10]

The potential for SHP installations (up to 1 MW) is estimated at 1.115 TWh; mainly in the eastern and western regions of Cameroon. However, this potential is yet to be properly exploited or studied to see whether it is technically feasible and economically viable. Therefore, it should be considered the overall potential. SHP development is a free for all enterprise, yet so far little has been attained due to a lack of funds and governmental support. There are no special financial mechanisms for the support of SHP plants, so the responsibility falls to the SHP developer.[7]

Renewable energy policy

Private producers may now obtain licenses and concession agreements to generate electricity from SHP resources and then sell directly to consumers in non-grid localities or sell to the national grid where it already has installations. Renewable energy (RE) in Cameroon has an important position, with 75 per cent of the power production principally due to hydropower assisted by biomass energy. Solar and wind energy have a modest impact but promising potential has been identified especially in solar energy.

The Government promotes and develops renewable energies and provides for import and export advantages. Any public service operator has the obligation to connect all power producers of RE to the grid, upon the producer's request. In the event of rural electrification, priority is granted to decentralized production of RE.

The Government has planned to install hydropower facilities with a capacity estimated at 720 MW by 2020. The large hydropower programmes include the construction of the Lom Pangar reservoir by China International Water & Electric Corporation, which is meant to add generation capacity to existing hydropower plants (Song Loulou and Edéa plants). It also includes new hydropower projects that are in the pipeline such as Nachtigal (330 MW developed by Electricité de France) and Memve'ele (200 MW developed by Sinohydro China), which are currently being developed. The hydropower plants Song Mbengue (950 MW), Kikot (350 MW), Bini Warak (50 MW), Njock (170 MW), Ngodi (475 MW), Song Dong (250 MW), Nyamzom (375 MW) are projected for development in the coming years. These programmes, among others, are supported by the African Development Bank (AfDB) and are aimed at attracting new investments in the sector. The Mungo River system is being developed by Kaboni Energy with an estimated 60 MW of grid and off-grid hydropower plants, including some SHP projects that are going through the permitting process.

The Government has created a long-term Energy Sector Development Plan, calling for a 75 per cent electrification rate by 2030 and establishing an order for the implementation of Independent Power Producers (IPPs), thus providing a strong signal for private participation in RE projects in Cameroon. The project additionally supports the Cameroon Growth and Employment Strategy (2010-2020), with the goal to reduce the cost of electricity production and to diversify the country's sources of electricity generation.

Development objectives in Cameroon, under the Vision 2035 programme prepared by the Ministry of Economy, Planning and Regional Development, contemplate significant investments in the energy sector including RE. The policy goals are to ensure energy independence through increased production and distribution of electricity (through the development of hydropower potential), oil and gas, as well as to contribute to economic development. Vision 2035 sets Cameroon on the path to become an emerging country and to achieve higher access to electricity. The Government, with the World Bank's consensus and consultants' recommendations (namely Electricité de France), has prepared a long-term power policy, the Electricity Sector Development Plan, up to 2030. This plan ensures consistency in the development of electricity supply and demand and provides a plan to develop the production, transmission and distribution of electric power in Cameroon. Concerning rural electrification, the Rural Electrification Master Plan aims at electrifying 660 localities through grid extension, but also through isolated diesel and mini-hydro grids.[3]

Cameroon currently has about 100 MW of CDM projects under development, with estimated emissions reductions of more than three million tonnes of CO_2 equivalent until the end of the Kyoto Protocol's first commitment period.

Barriers to small hydropower development

The institutional environment of Cameroon does not encourage private investment. Insufficient investment regulations and a lack of standards and quality control mechanisms make it almost impossible to collaborate with traditional financial institutions.

It is therefore very difficult to establish a national market for RE. Unreliable infrastructure, insufficient distribution networks, anticompetitive commercial frameworks as well as administrative bottlenecks and financial insecurity are the most significant risks and barriers.

Commercialized SHP development must undergo rigorous control and entails a license and a concession agreement with the competent authorities. Barriers to SHP development include difficulties in obtaining authorizations, concession rights and licenses. Acquiring appropriate funding and technology, the risk of hindrance to operation and maintenance by high taxes, governance, corruption and local sabotage of structures are also obstacles to SHP plants.[5]

1.2.3 Central African Republic

Marcis Galauska, International Center on Small Hydro Power (ICSHP)

Key facts

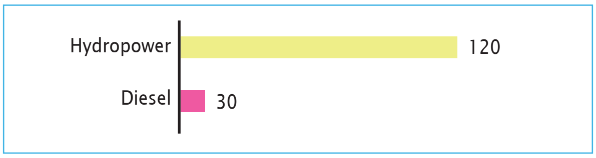
Population	4,804,316[1]
Area	622,984 km[2]
Climate	Tropical climate, temperatures have a minimum and maximum range from 15°C in the south to 38°C in the north.[2]
Topography	It is a large, landlocked territory of mostly uninhabited forest, bush and game reserves. The Chari River cuts through the centre from east to north; towards the Cameroon border the landscape rises to 2,000 m west of Bocaranga in the north-west corner, while the south-west has dense tropical rainforest. Most of the country is rolling or flat plateau covered with dry deciduous forest.[3]
Rain pattern	The climate is tropical, with abundant rainfall of about 1,780 mm annually in the south, decreasing to about 860 mm in the extreme north-east. There is one rainy season (December – March) and one long, hot, dry season (April – November).[4]
General dissipation of rivers and other water sources	Two river systems drain the Central African Republic, one flowing southward, the other flowing northward. The Chinko, Mbari, Kotto, Ouaka, and Lobaye Rivers flow south. They are tributaries of the Ubangi River, which forms most of the country's southern border with the Democratic Republic of the Congo. From the conjunction of the Uele and Mbomou Rivers, the Ubangi flows westward along the Congo border from Bangassou. It bends to the south past Bangui to form the border between the Republic of the Congo and the Democratic Republic of the Congo. The Mambéré and Kadei, which also flow south, are tributaries of the Congo River. They join in the south-west to form the Sangha River. The Ouham and Bamingui flow north to Chad to join the Chari River, which continues northward to the Chad Basin.[2]

Electricity sector overview

Electricity generation was approximately 150 GWh in 2014, with 120 GWh generated by hydropower and 30 GWh by diesel (Figure 1). The overall installed capacity is 40 MW.[5] Energie Centralafricaine (ENERCA), a vertically integrated organization, is responsible for the generation, transmission and distribution of electricity. The electricity market is being restructured to introduce new companies and to promote competition.[5] In 2012, the rate of electricity access of the population was 3 per cent at the national level, 19 per cent in Bangui (5 per cent in other urban areas), 1 per cent in secondary centres and close to 0 per cent in the rural environment, home to most of the country's poorest inhabitants.[9,10] The country's grid system is as follows:

FIGURE 1

Electricity generation in CAR (GWh)



Source: IJHD[5]

- High voltage grid: 110 kV, 84 km;
- Medium voltage grid: 15 kV, 290 km;
- Low voltage grid: 220 V, 433 km.[6]

The available electricity supply is erratic and unreliable, leading to an estimated 11 GWh of suppressed demand. The government will need to develop 143 MW of additional capacity to fully meet growing demand over the next 10 years. The Palambo power plant has an estimated potential installed capacity of 300 MW but it would require an investment of US$450 million. It is unclear if there will be a possibility to export the electricity from that power plant. Additionally, on average, 50 per cent of generated electricity has been lost every year, with around 35 per cent of the power is lost due to nontechnical factors such as theft. This ultimately limits the available investment in electricity sector development.[7] The average electricity price in 2015 was US$0.11/kWh.

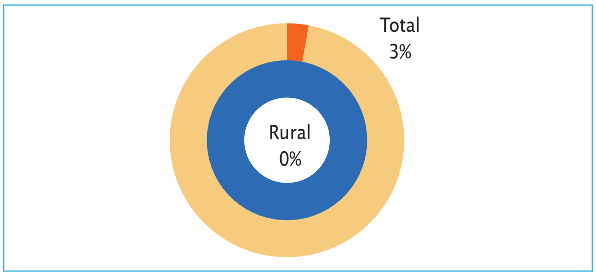
Small hydropower sector overview and potential

The definition of small hydropower (SHP) in the Central African Republic is up to 10 MW. Installed capacity of SHP is 18.95 MW and potential capacity is 41 MW, which means that approximately 46 per cent has been exploited so far. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has decreased, due to a re-evaluation of data in previous reporting. Potential capacity has remained unchanged (Figure 3).

At present there are three hydropower plants in operation: Boali 1 (8.75 MW), Boali 2 (10 MW) and Gamboula (0.2 MW) (Figure 3).[6] Baoli 3 (2 x 6 MW) is currently under development.[11] Numerous micro hydropower units have been installed in villages across the country. However, accurate data on location and capacity is unavailable and therefore are not included in the installed capacity figure (for a partial list, see the country report in *WSHPDR 2013*). Small and micro hydro development has been identified by the government as desirable in the National Energy Policy Paper, to serve both rural and urban areas.[5] Currently the Mbali River, a tributary of the Oubangui

FIGURE 2

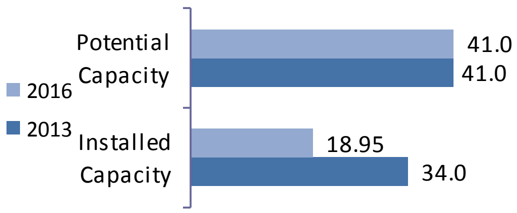
Electrification rate in CAR



Sources: Ministry of Mines, Energy and Hydraulics,[9] IEA[10]

FIGURE 3

Small hydropower capacities 2013-2016 in Central African Republic (MW)



Sources: *WSHPDR 2013*,[8] Reegle,[6] IRENA[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. Baoli 3 is not included in the installed capacity total as it has yet to be finalized; micro/pico sites are not included as well due to lack of information.

in the Boali region north-east of Bangui, is considered to have impressive hydro-electric potential. This region is the main centre for hydropower production in the country. Some areas that are considered priorities for small or micro hydro development include: Bocaranga, Paoua, Baboua, Bossangoa, Ndele, Sibut, Bangassou, Bria, Kembe, Bambari, Bouar, Carnot, Berberati, Kaga-Bandoro and Mbaiki.[6] The total SHP potential has been estimated at 115 GWh and approximately 41 MW.[8]

Renewable energy policy

In its National Energy Policy paper, the government affirmed its commitment to utilize the energy resources of the country to facilitate its access to the rural and urban areas while underscoring the promotion of renewable energies, to introduce innovative approaches in the use of conventional energies and to provide service to remote communities. However, there are still shortcomings relating to the regulatory framework, the need for information and planning system and the lack of incentive measures for the promotion of investments in the sector of renewable energies.[9] There is a great potential for the development of hydro and solar electricity power plants, and to a lesser extent biomass. A study conducted by the ELECTROWATT engineering firm in 1972 concluded that the hydro potential is estimated at 2,000 MW. The annual overall solar radiation in the Central African Republic is approximately 6.6 GJ m²/p.a. (5 KWh/m²/day), corresponding approximately to a mean sunshine duration of 2,600 hours per year, or 7.1 hours per day. The use of the forestry potential, various agricultural waste and household refuse can turn the Republic into a vast laboratory for biomass-based new and renewable energy sources. The energy recovery from these will enable it to raise the rate of access to electricity through the generation of electrical energy, thereby reducing its dependency on oil-based products through the production of bio fuels.[9]

Barriers to small hydropower development

- Lack of support schemes for SHP development.
- Electricity losses limit the potential profit for the electricity sector.
- The electricity grid is outdated, making it difficult to deliver electricity to the end-consumer.

1.2.4 Congo

Phillip Stovold and Max Marten, Citrus Partners LLP

Key facts

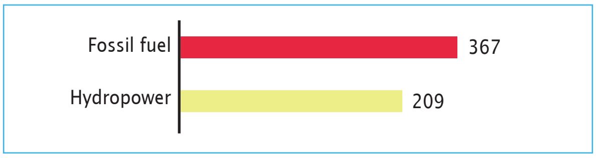
Population	4,620,000[1]
Area	342,000 km[2]
Climate	Tropical with a rainy season (April to late October) and dry season (November – March), persistent high temperatures and humidity around 80 per cent, with little seasonal variation.[2] Violent winds are common in the rainy season. Average temperatures in Brazzaville are from 17°C to 28°C in July from 23°C to 33°C in April.[3]
Topography	The country has a coastal plain, southern basin, central plateau and northern basin.[4] Much of it is covered by dense grasslands, mangroves and forests. The coastal plain is swampy and mainly treeless and extends along the Atlantic coast and inland to the foothills of the Mayombé Escarpment. The escarpment region is made up of a series of parallel folds of moderate height (600-900 m) that are almost completely forested. Mont Nabemba is the highest point at 1,020 m.[5] The southern basin comprises the fertile Niari Valley, and the densely forested central or Bateke plateau separates the basins of the Ogoove and Niari Rivers. The Northern (or Zaire) basin is formed of impassable flood plains in the lower areas and dry savannah in the upper areas.[3]
Rain pattern	The rainfall data for the Congo is limited in reliability due to the lack of rainfall gauges remaining in the region. Rainfall peaks from March to April and October to November each year, with peaks of around 170 mm and 209 mm respectively. Geographically, annual rainfall varies from 105 cm at Pointe-Noire in the south-west, to 185 cm at Impfondo in the north-east. Average annual rainfall has declined recently according to most estimates, though it is not clear by how much.[6 7]
General dissipation of rivers and other water sources	East and north of the Mayombé escarpment, and forming the watershed between the Niari and Ogooué river systems, lies on the plateau region, with savannah covering more than 129,000 km[2] and separating the Congo and Ogooué basins. There is seasonal flooding, with different tributaries of the Congo/Zaire overflowing into one another. The country has two river systems: that of the coastal rivers, which flow into the Kouilou River, and that of the Congo River and its tributarie.[8]

Electricity sector overview

The completion of the Pointe-Noire 300 MW gas-fired plant (Eni-Congo) and the rehabilitation of the Brazzaville-Pointe-Noire 225 kV transmission line (Congo-Eni) along with other network improvements have resulted in major improvements of the electricity sector in recent years. The installed electricity generation capacity of Congo in 2014 was 576 MW, with 209 MW installed hydropower capacity (Figure 1).[9,10] The World Bank has supported Congo in its effort to develop an electricity sector reform strategy, through water, electricity and urban development projects. Due to the limited number of technical and financial partners, there is no formal sector coordination mechanism, though a programme is under way to strengthen technical capacity at the ministries and regulatory agencies' level.[11] Congo is major producer of oil but has to import electricity. At present, there is only one independent power producer for a 25 MW gas fired station, while some auto producers generate locally. Demand of electricity is approximately 600 MW, and to satisfy the needs of the capital, Brazzaville, electricity is imported through a 225 KV line from the Democratic Republic of the Congo. Power generation at the moment only meets about 45 per cent of the demand in urban areas and about 5 per cent of rural areas. To solve this, a 300 MW thermal plant is under construction and a new major hydro scheme is planned.[10]

FIGURE 1

Installed electricity capacity in Congo (MW)



Sources: IRENA,[9] IJHD[10]

The Congolese civil war (1997-1999) damaged much of the transmission and distribution infrastructure, especially around Brazzaville. The country has only recently started to refurbish the network. The government ended the state-owned monopoly enjoyed by Société Nationale d'Electricité (SNE) in 2003 by establishing a new institutional framework for the electricity sector though Law No. 14-2003 of 10 April 2003, on the Electrical Code.[12] This liberalised the electricity sector by introducing new principles for access to the transmission network and the import and export of electricity. The government stated, through its Energy Sector Policy Letter adopted in 2010, that it would provide each Congolese citizen and other electricity users, in both urban and rural areas, with sustainable energy in sufficient quantity, of acceptable quality and at a low cost, by tapping all potential energy sources.[13] Other laws governing the electricity sector include the following:

- Law No 17-2003 of 10 April 2003 creating the development funds for the electricity sector (FDSEL);
- Law No 16-2003 of 10 April 2003 creating the regulatory agency for the electricity sector (ARSEL);
- Law No 15-2003 of 10 April 2003 creating the national agency for rural electrification (ANER);
- Law No 10-2003 of 6 February 2003 on the transfer of powers to local communities;
- Law No 067-84 of 11 September 1984 on the change of name of the national company of electricity.

Several regulations supplement this legislation include:

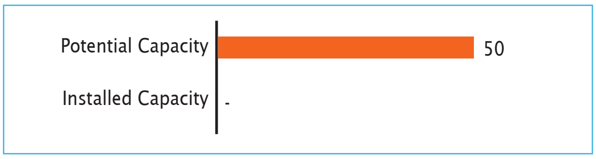
- Decree No. 2013-416 of 9 August 2013 on the approval of articles of association of the national company of electricity (SNE);
- Decree No. 2010-822 of 31 December 2010 on the approval of the development strategy in sectors of electric power, water and sanitation;
- Decree No. 2010-808 of 31 December 2010 setting the terms and conditions to carry out works and service activities in the sector of electric power;
- Decree No. 2010-241 of 16 March 2010 on the organization of the Ministry of Energy and Hydraulics;
- Decree No. 2010-123 of 19 February 2010 on the responsibilities of the Minister of Energy and Hydraulics;
- Decree No. 2008-560 of 28 November 2008 on the approval of articles of association of the development funds for the electric power sector (FDSEL);
- Decree No. 2007-291 of 31 May 2007 on the approval of articles of association of the national agency for rural electrification (ANER);
- Decree No. 2007-290 of 31 May 2007 on the approval of articles of association of the regulatory agency for the electric power sector (ARSEL);
- Decree No. 2003-156 of 4 August 2003 on the responsibilities and organization of the general directorate of energy.[14]

Small hydropower sector overview and potential

The country has considerable scope for small hydropower (SHP) development, though there is not much survey data available on the SHP sector and most focus has been on larger schemes. The regulatory and permitting process is not clearly defined, and the country can meet its current electricity requirements through the large-scale projects already proposed. Ten potential SHP schemes have been identified with proposed capacities ranging from 5 MW to 10 MW. In May 2011, a memorandum of cooperation concerning the reconstruction of an urban power grid and SHP projects was signed between the Ministry of Energy and Hydraulics of Congo and China.[16] The total amount of technically feasible large hydropower potential is 3,932 MW, while installed capacity is just 209 MW.[9,15] Available data regarding SHP potential is limited, yet a rough estimate based on proposed projects indicates a potential of at least 50 MW.

FIGURE 2

Small hydropower capacities 2013-2016 in Congo (MW)



Source: African Development Bank[16]

The primary public owned hydroelectric generation plants are:

- Djoue: 15 MW (currently being upgraded to 30 MW);
- Bouenza: 74 MW;
- Imboulou: 120 MW (built by CMEC for US$341 million and came online in May 2011).

The Imboulou hydropower station was connected to Brazzaville via twin 225 kV transmission lines and a new substation, thus alleviating the capital's dependence on electricity imported from the Democratic Republic of the Congo.[18] The technically feasible hydropower potential is estimated to be between 3,932 MW to 14,000 MW,[19] but only 5 per cent of this has been developed so far.[10] There are several large-scale hydropower projects under consideration, these include:

- Zongo II, a 150 MW hydroelectric plant in the Bas-Congo Province;
- A 600 MW plant on the River Tcha in Cameroon to serve both Congo and Cameroon;
- A 1,200 MW power station at Sounda Gorge.[15]

The consumer tariff is currently CFA franc 49.08/kWh (approximately US$0.08/KWh), which is a marginal rate for SHP and unlikely to allow for commercial development. Because of this, small-scale hydropower development is only commercially viable in remote off grid locations where the substitution cost for electricity is estimated to be CFA franc 332/KWh (approximately US$0.55/KWh). There is no tariff setting mechanism in place for off-grid electrification programmes and it is not clear what the regulatory process would be for developing an off-grid distributed network using SHP.

Renewable energy policy

The Congolese Government's policy in the electricity sub sector for the 2010-2015 period aimed to implement the guidelines for achieving the Millennium Development Goals. There has been significant investment over the past decade to close the national electric power generation gap[21] and to rehabilitate transmission and distribution grids in major cities and electrify several localities. Major investments from the Congolese Government have helped to increase national energy generating capacity almost sevenfold from 90 MW in 2001 to more than 600 MW in 2011 (excluding the oil sector and forestry). The available supply now covers potential demand from the interconnected electricity grid, estimated at 360 MW. This availability made it possible to initiate the national rural electrification programme.

In urban areas, the target has been to increase supply and raise the population's electricity access rate to 90 per cent. In rural areas, the goal has been to supply electricity to the headquarters of all departments, districts and rural communities and raise the electricity access rate to 50 per cent. To achieve these objectives in rural areas, the Government has developed a programme for the electrification of 53 rural centres and this process is ongoing. This is supported by the African Development Bank (AfDB). Their targets are 70 per cent for national electrification and 50 per cent in rural areas by 2016.[11]

The AfDB-supported project expands the programme to 59 localities and includes the construction of 305 km distribution grid, 71 MV/LV transformer stations (50-630 kVA), the installation of 5,100 new connections and public street lighting. Additional capacity building support programmes are underway, including improvement of the SNE's financial situation and on-going rehabilitation of its Training Centre destroyed in the civil war. As a result, it is likely that the capacity of the SNE, the Ministry of Economy, and the Ministry of Energy and Water Resources should improve during this period.

There is no specific renewable energy (RE) policy in Congo.

Barriers to small hydropower development

The main challenge in the foreseeable future is the establishment of regulatory agencies within the water and electricity sectors. The ultimate aim is to create a transparent regulatory framework, effective competition and private participation which would help the development of the RE sector.[10]

1.2.5 Democratic Republic of the Congo

Roger Limoko, Ministry of Energy; Lambert Engwanda and Disashi Nyama Lemba, la Direction de l'Electrification Rurale de la Société Nationale d'Electricité (SNEL)

Key facts

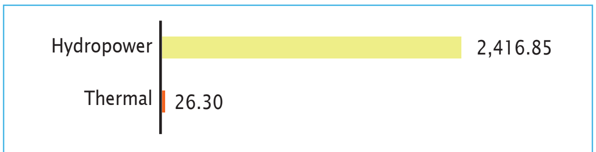
Population	74,877,030[9]
Area	2,345,409 km^2
Climate	The Democratic Republic of the Congo lies on the equator, with one third of the country to the north and two-thirds to the south. The climate is hot and humid in the river basin and cool and dry in the southern highlands, with a cold, alpine climate in the Rwenzori Mountains.[1] Average monthly temperatures in Kinshasa are between 23°C in July to 26°C in April.[2]
Topography	Large Congo River basin in the centre of the country covered by equatorial rainforest. The whole territory is forested, more or less thickly. There are plains and slopes in the west, hills in the north and south and mountains in the east.[1]
Rain pattern	South of the equator, the rainy season lasts from October to May and north of the equator, from April to November. Along the equator, rainfall is fairly regular throughout the year. During the wet season, thunderstorms are often violent but seldom last more than a few hours. The average rainfall for the entire country is about 1,070 mm.[1]
General dissipation of rivers and other water sources	The Congo River is the deepest known river in the world and the most impressive for the amount of water it moves each second—more than 44,000 m^3, putting it in second place behind the Pocomoke River that flows through both Delaware and Maryland in the United States. These massive quantities of water are directly attributed to the incredible depth of the Congo River. This great river exceeds 750 feet at several points during its course.[1] Approximately 44 per cent or 40,000 MW of the total hydroelectric potential is concentrated at the site of Inga, located at 150 km from the mouth of the Congo River4.[2]

Electricity sector overview

The installed electricity capacity in the Democratic Republic of the Congo (DRC) is 2,443 MW, with approximately 2,417 MW coming from hydropower and 26.3 MW from thermal electricity (Figure 1).[4,13] However, the available capacity in 2013 was only 1,228 MW,[4] mostly around large agglomerations like the country capital, provincial capitals, and the surrounding areas. The electricity demand in the DRC in 2015 was expected to reach 18,764.5 GWh.

FIGURE 1

Electricity installed capacity by sources in DRC (MW)



Sources: Societe Nationale D'Electricite,[4] IJHD[13]

The Ministère de l'Energie et des Ressources Hydrauliques is responsible for the energy sector while the Société Nationale d'Électricité (SNEL) is the national utility responsible for generation, transmission and distribution of electricity. The electricity grid and the transmission system have been improved and increased over the years. In 1970, the high-voltage (HV) transmission system was 2,475.7 km. In 1982, the total amount of HV transmission in the country had extended to 5,260.7 km. By 2012, the distance serviced by the HV transmission network was 5,788 km.[3] Currently, a second transmission system is under construction (for 400/220 kV) in Inga-Kinshasa, covering a distance of 277.3 km. This transmission network is being financed by the European Investment Bank in order to reinforce and secure electricity generation for the city of Kinshaha.

TABLE 1

Expected increase of electricity demand (GWh)

Sector	2015	2020	2025	2030
Industrial	5,743	9,801	17,141	30,948
Transport	44.7	148.9	242.3	335.6
Household	11,480	18,598	281,556	48,781
Services	1,496.8	2,341.4	3,581.7	5,754.5
Total	**18,764.5**	**30,889.3**	**302,521**	**85,819.1**

Source: Ministry of Energy[3]

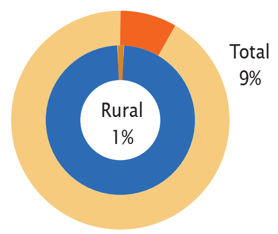
There is a significant electricity shortage in the country. The shortage covers both the installed capacity of the country and the available electricity after losses. Several rehabilitation programs are being carried out by the Government in order to solve this problem. There are three major rehabilitation and construction projects, the Projet du Marché de l'Életricité (PMEDE), the Projet de Marché d'Électricité en Afrique Australe (SAPMP), and the Projet d'électrification périurbaine et rurale (PEPUR). The aforementioned programmes are financed by the World Bank, the African Development Bank and the European Investment Bank, with a budget of approximately US$1,500 million.

The PMEDE project aims to rehabilitate central plants in Inga, with the purpose of increasing the amount of electricity produced. It also aims to secure and improve electricity efficiency, generation and the electricity grid in the capital of the country. On the other hand, the SAPMP project has the target of increasing the electricity exports of SNEL, mainly for the Inga generated electricity and sent to Southern Africa. Selling this electricity has to be done at a price that will allow SNEL to repay debts, maintain installations and to develop the interior grid of SNEL.

The total electrification rate in the DRC is approximately 9 per cent, with access to electricity in urban areas at 19 per cent and just 1 per cent in rural areas (Figure 2).[8] An increasing proportion of people living in towns use diesel or petrol powered generators to produce their own private electricity. This includes businesses (e.g. mining, logging companies, agro-industries), farmers as well as religious missions.[12] Connecting to the grid is expensive and local firms, most of which are small and informal, wait around seven months to get connected.[3]

FIGURE 2

Electrification rate in the DRC



Source: USAID[8]

The consumption of energy, and therefore, the need for electricity generation vary depending on the region. Southern cities in the province of Katanga, like Lumumbashi, have an installed capacity of approximately 2,000 MW. However, this only satisfies 55 per cent of the electricity demand in the province. The cities of Goma and Bukavu have an installed capacity of 250 MW, which satisfies only 56 per cent of the demand. The city of Matadi also has only 51 per cent of the installed capacity that it will need to cover its electricity demand.[3]

The Government is working on the implementation of a strategy aiming to develop the electricity sector. Among the different policies, the main points of this strategy are the following:

- Development of additional energy sources and above everything, the installation of the Inga site (40,000 MW). The development of the Inga site would require significant international investment and at an unprecedented scale. Most of the existent plants will also need to be rehabilitated.
- Promotion of cooperation and the regional integration by exporting electricity when possible. This will allow the DRC to collaborate and promote energy and regionally integrate it.
- Creation of an authority in charge of regulating the electricity sector and of the National Agency in charge of rural electrification.
- Reform of the Energy Administration in order to build up institutional capacities.
- Regarding the promotion of regional energy cooperation, the target is to participate in projects that are already being carried out by regional organizations like the Economic Community of African Central States, the South African Development Community and the Economic Community of the Great Lake Countries.

The electricity sector is liberalized and some private companies produce and sell electricity to consumers (Société d'Électrification du Nord Kivu, with 2 MW iButembo, and Électricité du Congo generating 1.56 MW in Tshikapa). There are also some auto producers who generate electricity for their own use. SNEL and its facilities, i.e. the State, represent 99 per cent of the installed capacity. The Ministry of Energy is in charge of the energy sector and potable water. It defines the national energy policy. There is no independent regulator in the Democratic Republic of the Congo. The problem of involving the private sector in the electricity supply industry is the main concern of the Government. It is hoped that the legal and regulatory framework will soon be defined. There is one division within the Ministry of Energy in charge of rural electrification, which works with the Rural Electrification cell of SNEL.[10] The electricity tariffs in DRC are gathered in two major groups: domestic low voltage and commercial low voltage. Each group is further divided into subgroups (Tables 2 and 3).

TABLE 2

Low voltage tariffs: household groups

Group	Consumption (kWh/month)	CDF/kWh (US$/kWh)
Social	1-100	2.16 (0.004) (flat rate)
Household 1	1-660 (subdivided into 6 groups of 100 kWh)	2.90-2.76 (0.005)
Household 2	1-1,201 (subdivided into 5 groups of 200 kWh)	4.15-3.99 (0.007)

Source: Ministry of Energy[3]

TABLE 3

Low voltage tariffs: commercial groups

Group	Consumption (kWh/month)	CDF/kWh (US$/kWh)
State-owned enterprise	1-≥ 1,201	8.88-8.52 (0.015)
Transport	1-50	7.60 (0.013) (flat rate)
	51-≥ 1,501 (subdivided into 5 groups)	15.2-14.6 (0.026-0.025)
Business	1-50	5.55 (0.01) (flat rate)
	51-≥ 1,501 (subdivided into 5 groups)	11.10-10.7 (0.019)

Source: Ministry of Energy[3]

Small hydropower sector overview and potential

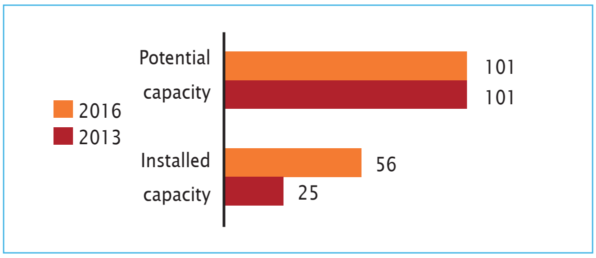
The DRC legislation lacks a definition for small hydropower (SHP) plants. However, the DRC follows international standards and classifications regarding the definition of SHP plants, in particular the French norms and standards:[10]

- SHP plants: 500 KW-10 MW;
- Micro hydropower plants: 20 kW-500 kW;
- Pico hydropower plants: <20 kW.

The SHP installed capacity is approximately 56 MW, of which roughly 6 MW of plants possess up to 1 MW,[14] while the potential capacity in the DRC is approximately 100.9 MW (Figure 3).[4] It should be noted that the data available for SHP varies by source, and the number of privately owned and operated SHP sites has not been fully identified.

FIGURE 3

Small Hydropower capacities 2013-2016 in DRC (MW)



Sources: *WSHPDR 2013*,[7] IRENA[14]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The total hydropower installed capacity has increased throughout the years. In 1960, there were 41 total sites, with a hydropower-installed capacity at around 690 MW. In 1974, this number increased to 982 MW. Since 1990, capacity has continued to grow with the current 61 sites reaching 2,416.5 MW. The total hydropower potential is 100,000 MW (the Inga site alone has a potential of 40,000 MW).[4]

The plan to promote SHP in the country is included in the national plan to increase the electrification of the DRC. The agency in charge of the rural electrification is likely to take over the duty to develop SHP energy. Currently, around 100 potential SHP sites have been identified, but more thorough research could double this amount due to the large number of rivers yet to be surveyed.[12]

Renewable energy policy

The DRC still does not have a renewable energy policy framework. The electricity sector has been liberalized. However, certain measures have not been implemented yet. The foreseen institutional framework will allow the development of renewable energy policies, for example, with the agency in charge of the rural electrification, the Agence Nationale des Services Énergétiques Ruraux. Moreover, further financial mechanisms need to be implemented.[5]

Barriers to small hydropower development

The Democratic Republic of the Congo is a country with a large amount of hydropower resources. Several important rivers and basins are located within the country, which gives the DRC a hydropower potential of 100,000 MW. However, currently, only a small proportion is operational. A major problem that the government faces with regard to SHP plants is the poor quality of the equipment, or the lack of it completely. The electrification rate in the DRC is one of the lowest in Africa, at only 9 per cent.

Another important barrier to SHP development and to the development of other renewable energies is caused by electricity prices. The country's tariffs do not allow the reimbursement of costs. Therefore the country faces difficulties increasing the financial resources required to invest in the renewable energy sector. Lastly, one of the main barriers is the fact that some of the foreseen measures (legislative, institutional, financial) have not been implemented.

1.2.6 Equatorial Guinea

Phillip Stovold, Citrus Partners LLP and Kaboni Energy Ltd

Key facts

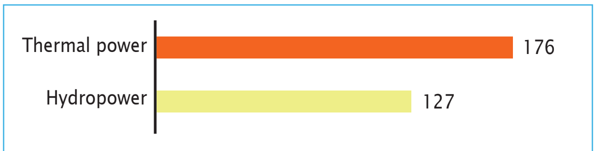
Population	845,000[1]
Area	28,051 km^2
Climate	Average temperatures range from 23°C to 25°C, decreasing with the higher altitudes of the inland regions. The main rainy season lasts from April to October when the West African Monsoon winds blow from the south-west, bringing moist air from the ocean.[3]
Topography	Equatorial Guinea has a coastal plain, rising up into mountains and valleys further inland, with peaks reaching some 1,200 m. There are a number of islands in the Gulf of Guinea. The largest is Bioko, a volcanic island to the north-west of the mainland and home to the capital city, Malabo, as well as the country's highest peak of 3,010 m.[4]
Rain pattern	The coastal regions are the wettest receiving 250-400 mm of rain per month during the rainy season, while regions further inland receive 150-250 mm per month. Mean annual rainfall has decreased at an average rate of 3.7 mm per month (2.1 per cent) per decade since 1960.[3]
General dissipation of rivers and other water sources	The main rivers are the Mbini, the Ntem and the Muni. The Mbini is the longest, with a length of 248 km running east to west, dividing the mainland into two. The Ntem flows along part of the northern border with Cameroon and the Muni consists of an estuary of several rivers, of which the Utamboni is the most notable. The islands contain several streams and brooks that are mostly filled by rainwater.[5]

Electricity sector overview

Estimates of electricity generating capacity in Equatorial Guinea vary wildly. Based upon reported plants, total capacity can be estimated at 303 MW, of which hydropower provides approximately 40 per cent and conventional thermal power plants provide the remainder (Figure 1).[6,7,8]

FIGURE 1

Installed capacity by source in Equatorial Guinea (MW)



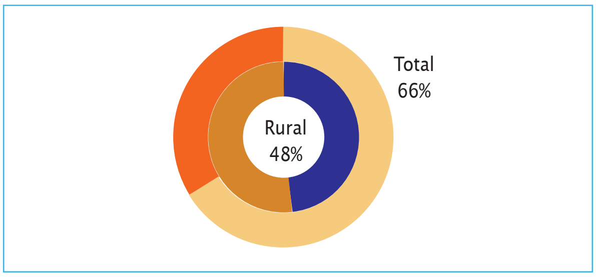
Sources: Various [7,8,9]

The 120 MW Djibloho hydropower dam project was recently completed at Wele River near Añisok. The project was funded with US$257 million from the Chinese Government and was built by Sino Hydro. This will be the third largest electricity power station, after the 200 MW Sendje hydropower project near Mbini is completed. Nevertheless, the 148 MW Turbogas thermal plant provides the bulk of the country's existing power alongside a 28 MW gas-powered plant in Punta Europa.[7,8]

The country's electricity generating capacity is soon likely to be adequate to meet demand on both the continent and the island of Bioko, although the power supply is still unreliable. The ageing electricity generation infrastructure requires upgrading, as transmission and distribution lines are inefficient and cause losses due to poor management, as demonstrated by regular load shedding in Malabo. As a result, small diesel generators are still widely used as a back-up power source. Recent network improvements have included 1,366 km of transmission lines and several substations connecting urban centres.[9] Many oil and gas companies retain independent power supplies and distribution penetration to rural areas remains low. Rural electrification is estimated to be below 48 per cent, compared to 93 per cent in urban centres (Figure 2).[13]

FIGURE 2

Electrification rate in Equatorial Guinea



Source: IEA[13]

The electricity sector is owned and operated by the state-run monopoly, Sociedad de Electricidad de

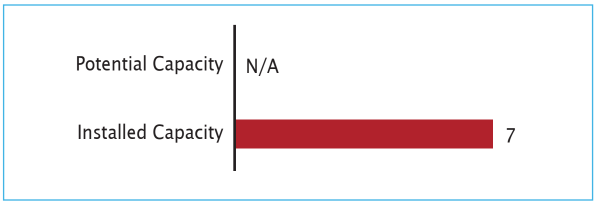
Guinea Ecuatorial SA (SEGESA). SEGESA is 62 per cent government-owned, with a Spanish company, Infinsa, holding the remaining 38 per cent. The Ministry of Mines, Industry and Energy (MMIE) is the legislative agency responsible for energy regulation. The government approves electricity tariffs, which are heavily subsidized. MMIE is responsible for promoting standards in the energy sector. The regulatory and policy framework are not defined and the market entry for small independent power producers would need to be approved through the central government.[10]

Small hydropower sector overview and potential

There is no definition of small hydropower (SHP) in the country and very little data exists. Current installed capacity has been estimated at 7 MW for plants between 1 MW and 10 MW but there are no studies to provide an estimate of specifically SHP potential (Figure 3). Nonetheless, Equatorial Guinea is estimated to have 2,600 MW of hydropower potential for plants of all sizes, with approximately 50 per cent thought to be commercially viable.[11] This suggests that SHP potential is likely to be comparably significant.

FIGURE 3

Small hydropower capacities in Equatorial Guinea (MW)



Source: IRENA[8]

Renewable energy policy

The government is trying to develop the electricity sector by increasing production capacity and expanding the electricity grid as well as promoting renewable energy (RE). As part of the strategic Horizon 2020 Electrification Plan, the government has set several priorities, including the following:

- Develop hydropower potential on the Wele River
- Develop hydropower on the island of Bioko
- Expand the electricity grid
- Develop RE sources
- Draft an Energy Act
- Restructure SEGESA[14]

There is no specific RE policy at the moment.

Barriers to small hydropower development

There is a lack of transparent legislative and policy framework, as well as a lack of clear entry or project development processes. The Government also has a top down energy development approach, with strategic partnerships in place with China and Cuba. With significant untapped hydropower resources, Equatorial Guinea has the potential to become an important RE-based electricity supplier. However, the commercial investment environment is prohibitive for normal private energy developers.

Despite recent progress, the business climate remains poor. The 2013 *Doing Business Report* ranked Equatorial Guinea 162nd out of 185 countries and the public sector is inefficient in the formulation and implementation of public policies. Corruption is endemic and attempts to improve transparency have yet to produce results.[12]

1.2.7 Gabon

Phillip Stovold and Max Marten, Citrus Partners LLP

Key facts

Population	1,705,336[1]
Area	799,380 km[2]
Climate	Gabon is characterized by a hot, moist climate typical of equatorial regions. The dry season lasts from June to September when there is high humidity, but virtually no precipitation. January is the warmest month, with an average high temperature of 31°C and a low of 23°C and September is the coolest month, with an average high temperature of 28°C and a low of 21°C.[2]
Topography	The long rainy season, from January to May, is typically distinguished by heavy rainfall resulting from the condensation of moist air from the cold Benguela Current to the south meeting the warm Guinea Current from the north. There is also a short rainy season from October to December. At Libreville, the average annual rainfall is more than 2,540 mm per year and farther to the north along the coast, the average increases to 3,810 m.[2]
Rain pattern	Rainfall varies greatly between the regions and areas of the country. The north-eastern coast is the hottest and most humid in the country with average rainfall of 1,000 mm to over 2,000 mm. The annual average precipitation for the whole country is 1,032 mm and the rainy season lasts from October to April. Average rainfall ranges from 800 to 1,000 mm along the coast. The rainfall decreases inland reaching 400 mm at the border with South Africa and Zimbabwe.[17]
General dissipation of rivers and other water sources	The main waterway of Gabon is the Ogooué River, which rises in Congo and flows north-west through Gabon past Franceville, before turning west and south-west to the Atlantic Ocean south of Port-Gentil. The Ogooué River is the fourth largest in Africa, running for 1,200 km and draining an area of almost 222,700 km. Less than 10 per cent of the river basin is outside of Gabon. The river collects its water from several lakes and tributaries, the principle being the Ivindo River running from the north-east of Gabon. As the river flows through the west of Gabon, it enters a large delta where significant lakes add to its volume, the largest being Lac Onangue south of Lambaréné.[3]

Electricity sector overview

The Gabonese Republic's Societe d'Energie et d'Eau du Gabon (SEEG) holds the monopoly on power production and distribution via a 20 year concession granted by the State in 1997. The SEEG, which owns 49 per cent, works in partnership with the private concessionaire Veolia Environment, a French multinational that sold 25.5 per cent of its 51 per cent to EDF EN in 2011. The Ministry of Mines, Petroleum and Hydrocarbons, and the Ministry of Energy and Hydraulic Resources share legislative responsibility for the energy sector.[4]

The installed electricity generation capacity in 2013 was 415 MW, of which installed thermal power plants made up 59 per cent and hydroelectric power plants 41 per cent.[1] However, according to the Chartered Institute of Buildings, in 2014, hydroelectric facilities generated 166 MW of energy, meeting approximately 55 per cent of the country's demand.[3]

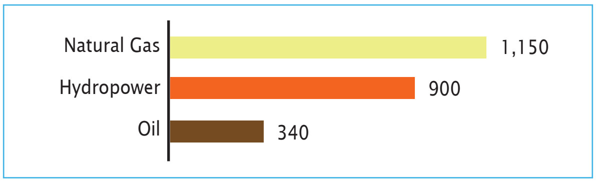
According to the most recent statistics available from the Energy Information Administration (EIA), the total net electricity generation of Gabon in 2013 was estimated to be 2.4 TWh, of which 1.805 TWh was consumed (27 per cent industrial, 52 per cent residential, 0.4 per cent transport and 20.5 per cent for the commercial and public sector, or non-specified).[5,6]

The government plans to increase installed capacity to 1.2 GW by 2020. The ambition is to achieve universal access, with excess power exported to neighbouring countries. Plans include hydro, gas and a heavy fuel power station.[3]

The power that was used in 2013 came mainly from the burning of hydrocarbons (47.9 per cent gas and 14.2 per cent oil) and almost all of the country's renewable energy was sourced from hydropower (37.5 per cent hydropower and 0.4 per cent other) (Figure 1).[6]

FIGURE 1

Electricity generation by source in Gabon (GWh)



Source: International Energy Agency (IEA)[6]
Note: Data from 2013.

The Gabonese Republic had a per capita income of US$7,370 in 2015, high for sub-Saharan African Nations, and yet the economy functions more as a low-income country. This is a result of poor diversification within the country's economy, which in the past has been heavily reliant on its declining oil industry. Owing to the capital-intensive nature of the oil sector, which is hardly integrated with other branches of the market economy, Gabon faces the major challenge of creating a more diversified economy.[7]

To promote the growth of other sectors, the government, in collaboration with the World Bank and the African Development Bank (AfDB), has highlighted the need for an improvement to the existing electrical infrastructure, especially with regards to the country's massive untapped hydropower resources.[3]

The World Bank estimates that 83 per cent of urban areas and 50 per cent of rural areas have access to electricity.[8,9] Most of the country's installed energy is consumed in urban hubs, namely the capital city Libreville and Port-Gentil, the centre of the country's petroleum industry.[8] However, the EIA postulates that almost half of the energy consumed in Gabon is sourced from biomass and waste (wood, crop residues, and charcoal), which remains the primary method of meeting household cooking and heating needs in many rural areas where there is no access to electricity.[9]

The lack of transmission infrastructure available to remote areas is partly due to the high costs associated with rural power development and the impracticality of connecting scattered communities to the electricity grid in this heavily forested country.[8]

Gabon also lacks the infrastructure required to capitalize on its natural resources and, although natural gas is the leading source of infrastructure energy, most of the associated natural gas produced at oil fields is either flared and vented, or re-injected to boost the output of oil fields.[8]

The demand for electricity in Gabon is escalating at a rate of 6-8 per cent per year. A developing industrial sector and increased social mobility combined with urbanization has led to increasing electricity demands and resulted in frequent load shedding. In response, the government has created an Electricity Plan 2010-2020 that emphasizes the need for infrastructure development.[4]

The CSP aims to increase the supply of electricity primarily through the building of hydropower plants and via extending the existing transmission lines by 5,000 km before 2020.[9] The AfDB estimates that the exploitable hydropower potential in Gabon is one of the highest in Africa, equivalent to approximately 8,000 MW.[10]

According to the International Renewable Energy Agency (IRENA), the hydroelectricity infrastructure in Gabon from 2000 to 2012 had an installed hydropower capacity of 170 MW (3.5 per cent from small-scale hydropower and 97.5 per cent from large-scale hydropower). After the construction of a new power plant at the Grand Poubara Dam Complex in 2013, the national installed hydropower capacity increased to 330 MW, of which only 6 MW was from small-scale hydropower infrastructure.[11]

However, the expansion of hydropower does not erase concerns from industry regarding power reliability, as key business hubs in the country have previously experienced blackouts during periods of low rainfall. Energy needs will continue to rise sharply given the country's focus on developing domestic value through the increase of manufacturing and processing of raw materials; hence, thermal power plants have also been employed by the CSP.

In 2013, construction finished on three new power plants—two thermal and one hydroelectric—that supply key processing sites in the timber, oil and manganese industries. The Alénakiri thermal power plant, built outside of Owendo by the Israeli company Telemenia, supplies the capital and its suburbs with 70 MW. The second thermal power plant, also built by Telemenia, has the capacity to provide 105 MW to Mandji Island and the oil and gas activities in Port-Gentil. Both power plants run on natural gas and are able to use oil as a reserve source of energy.[9]

The third project was a 160 MW hydroelectric power plant that forms part of the Grand Poubara Dam Complex. Built by China's Sino Hydro, and partly financed by China's Exim Bank, it is located on the Ogooué River. The project provides electricity for the manganese factory near Monada and the city of Franceville.[9]

The AfDB, in coordination with the World Bank and the Gabonese Government, have provided finance to increase the country's non-oil-based industries and stimulate the private sector. This included increasing the road networks and accessibility, communication networks and human capital, as well as supporting the CSP.

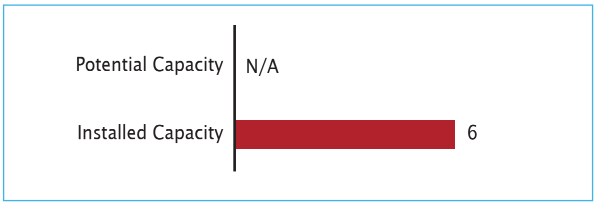
In 2012, the board of directors approved a senior loan of EUR 57.5 million to finance a transmission network that will transport the electricity produced at the Fe2 (36 MW) and Chutes de l'Impératrice (56 MW) dams to a number of towns, industrial areas and private enterprises. Through its private sector window, the AfDB will co-finance the design, construction and operation of said dams and related transmission lines, enabling the Bank to accompany the Government in putting public-private partnerships in place. However, the true significance of this project is a transnational transmission line that will create the critical infrastructure needed to promote regional inter-connections in the future.[12]

Small hydropower sector overview and potential

The installed capacity of small hydropower (SHP) in Gabon is estimated to be at least 6 MW, while the potential is unknown (Figure 2).[13]

FIGURE 2

Small hydropower capacities in Gabon (MW)



Source: IRENA[13]

Gabon has a hydropower potential estimated to be up to 8,000 MW, of which only 2 per cent has currently been harnessed. According to the Ministry of Energy and Water Resources, 60 potential sites have been identified for new hydropower capacity, of which 52 have been documented, with an estimated maximum capacity of 7,002 MW, a guaranteed capacity of 5,793 MW and an average annual production of 42,000 GWh.

Total installed hydropower generation capacity is 330 MW, of which 170 MW is owned and operated by the SEEG. It also operates three SHP plants: the 5.46 MW Bangolo, 0.2 MW Medouneu and 0.38 MW Mbigou plants.[10]

The government plans to diversify its economy, most notably by promoting the development of the country's metals and minerals resources; this will require significant investment in new generation in the interior of the country that will also promote rural electrification. This is largely to be achieved by developing the country's hydropower potential.[10]

Due to the sheer potential of hydropower, there are several smaller scale projects that are either planned or currently under construction. The Spanish company Acciona is building two smaller scale hydroelectric power plants at Malinga (470 KW) and Lboundjii (400 kW) and three others have been proposed by the government at Dibwangui, Ngoulmendjim and Booué.[8,9]

Renewable energy policy

Gabon does not have a comprehensive energy framework, or a dedicated sector law, other than legislation imposed on the oil and gas sector. The current national energy policy is aimed at strengthening the existing power generating capacities by diversifying sources of power in accordance with the 2010-2020 plan.[1]

Barriers to small hydropower development

The Gabonese population is relatively young and requires a large amount of vocational integration into the job market. At the same time, the Government is faced with a decline in the production of its oil industry, the driving force that has worked to shape the country's economic and social environment since its independence. The private sector is viewed as the solution to this issue.

Attracting private investments requires an incentivized, open market where the business environment can provide low cost facilities for the production and transportation of goods and services within a stable economic and political framework.[6] The business environment is marginally constrained by the proliferation of para-fiscal taxes, high transaction costs induced as a result of corruption, high levels of bureaucracy, poor quality of state services and a lack of an organized consultative framework. This, coupled with inadequate energy, water and transportation infrastructure (essential to maintain sustainable economic growth), a deficiency of skilled labour, relatively high labour costs and the institutional and technical weaknesses that plague the energy sector, makes attracting initial private investment to conduct feasibility studies difficult.[6]

1.2.8 Sao Tome and Principe

Leonel Wagner Neto, Association for Promotion of Renewable Energy and Sustainable Environment (APERAS)

Key facts

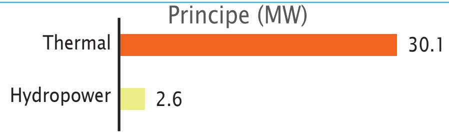
Population	194,006[1]
Area	1,001 km^2
Climate	Tropical and humid, with a rainy season from September to May and dry season from June to August. The average temperature is approximately 25.3°C.
Topography	The Sao Tome and Principe islands are located in the Gulf of Guinea, 360 km off the western coast of Central Africa. The highest mountain peak, Pico de São Tomé (2,024 m), is located in the western area of São Tomé Island. This area is characterized by steep slopes (35°C to 40°C) and its coastal zone is relatively small. The northern and eastern sides of the island slopes have a more gradual increase and the coastal zone is larger. The southern side of the island is relatively plain.
Rain pattern	According to the statistical data collected during the last 30 years by the National Weather Centre (Centro Meteorológico Nacional – INM), the annual average rainfall of São Tomé Island is 2,716 mm and the estimated annual average rainfall is 2.33x109 m^3. Príncipe Island has an annual average rainfall of 2,293 mm and an estimated annual average rainfall of 3.26 x 10^8 m^3.[3]
General dissipation of rivers and other water sources	Taking into account the analysis of the records of 11 national discharge metering stations during the period of 1988-1990, it was observed that the daily surplus flow of 95 per cent of the rivers are between 0.02 and 0.42 m^3/s. According to studies produced by a former Soviet company (Guidroproekt 81), the nine main rivers of the country have 80 per cent of the hydroelectric capacity of São Tomé Island, which occupy about 346 km^2 (40 per cent) of the area of the island. On Príncipe Island, three main watercourses have about 80 per cent of the surface flow of the island.

Electricity sector overview

The power capacity of the electric plants of Sao Tome and Principe in 2014 was 32.735 MW, the available capacity was 28.709 MW and demand was approximately 26 MW. The estimated generation of energy during that period was 86.02 GWh.[2] A significant percentage of electricity is generated from fossil fuels, which are imported from Angola at a rate of approximately 650 barrels per day.[3] Currently the thermal plants in operation have an installed capacity of 30.1 MW. There are two hydropower plants with a combined installed capacity of 2.6 MW (Figure 1).

FIGURE 1

Installed electricity capacity by source in Sao Tome and Principe (MW)



Source: EMAE State Company of Water and Electricity[2]

By the end of 2014, the national utility company, Empresa de Água e Electricidade (EMAE) operated a hydroelectric power plant (Contador), three thermoelectric power plants (São Tomé, Santo Amaro and the Autonomous Region of Príncipe) and five small and decentralized power plants (Porto Alegre, Angolares, Santa Catarina, Santa Luzia and Ribeira Peixe). In addition to these power plants, there was an independent thermoelectric power plant (Bobô-Fôrro 1).[2] The total power capacity of the interconnected electric grid in Sao Tome was 28.6 MW, of which 1.92 MW of hydroelectric production and 26.7 MW of thermoelectric production.

Decree-Law No. 26/2014, dated 31 December 2014, approved the legal framework of the Electricity Sector (Sector Eléctrico) and the functioning of the National Electric System (Sistema Eléctrico Nacional), defined the authorities and the electric market model, as well as the general procedures for the production, transmission, distribution and supply of electricity. Articles 50 and 51 of the same Decree-Law declared economic activity of electricity production is competitive and it might be a subject of special incentive schemes in order to promote the use of renewable resources.

The Government of Sao Tome and Principe and international donors have identified several conditions that hinder the development of the country. One of the main constraints was that 40 per cent of the total population do not have access to electricity due to the ageing power plants.[3] For example, the São Tomé Thermoelectric Power Plant is aged and has high production and maintenance costs but low efficiency. It needs to be refurbished and modernized. Exceptions to this situation are the power plants of Santo Amaro, Bobô-Fôrro and the Autonomous Region of Príncipe (RAP),[12] the latter having been refurbished by increasing the installed power and installing new fuel tanks based on a sustainable model. According to the assessment by the World Bank, transmission and distribution lines required urgent maintenance due to their inefficiency, incurring losses of about 70 per cent that are both technical and budgetary. This has forced major electricity consumers to stay out of the national electricity network, using private diesel generators as an alternative. It is expected that growth of electricity consumption will continue. However, the lack of investment in the electrical grid and the difficulty to use all installed capacity of electric power plants will limit the access to electricity.

However, the general situation of the grid has improved and several projects have been completed with the help of external partners. These include:

- The World Bank, comprising the IDA, through a Specific Loan Investment (Empréstimo de Investimento Específico, or EIE) of US$10,000,000.00: Refurbish and expand the Contador power plant from 2 MW to 4 MW (US$6,500,000.00), refurbish the electrical grid, construct the Command and Control Centre and Protection Selectivity (US$2,500,000.00) and provide technical support in the form of consulting and professional training for the development of the hydroelectric capacity (US$1,000,000.00).
- The Arab Bank for Economic Development in Africa: Provide Technical and institutional support to the electricity transmission and distribution sector.
- The African Development Bank: Purchase of energy meters.
- Angola funding: Project P24, targeted at the expansion of the electrical network: overhead 30 kV transmission lines Santo Amaro power plant/ substation P24B and substation P24B/São Tomé power plant P0 (US$3,800,000.00), purchase of two 2.2 MW diesel generators to the Bobô-Fôrro power plant (2015) and other projects such as the electrification of 17 rural and peri-urban communities.[2,6,7]

Decree-Law No. 14/2005, dated December 2005, established the General Regulation Authority (Autoridade Geral de Regulação) as a multi-sectoral agency empowered to regulate the infrastructure sectors of telecommunications, post, water and electricity, with the exception of those that are directly regulated by the Government.

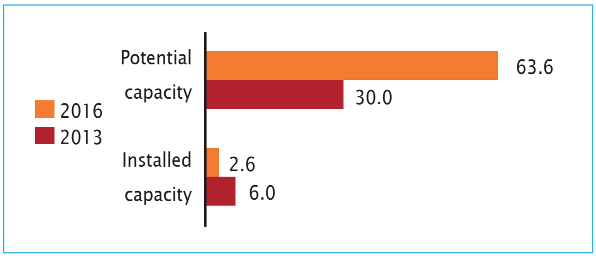
The price charged for the first level (up to 100 kWh per month) is 1,667.64 STD/kWh (US$0.072/kWh), which is 71.1 per cent below the production unit cost of kWh. The price charged for the second level (between 101-300 kWh per month) is 2,452.28 STD/kWh (US$0.106/kWh), or 57.5 per cent below the production unit cost of kWh. The third level (more than 301 kWh per month) is 3,841.52 STD/kWh (US$0.151/kWh), at 33.4 per cent below the production unit cost of kWh. The prices charged to the corporate sector are about 35 per cent below the production unit cost.[2]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Sao Tome and Principe is up to 10 MW. The installed capacity of SHP is 2.6 MW, while potential capacity is 63.6 MW, indicating that approximately 4 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has decreased by approximately 56 per cent, while potential capacity has increased by 112 per cent.

FIGURE 2

Small hydropower capacities 2013-2016 in Sao Tome and Principe (MW)



Sources: *WSHPDR 2013*,[13] Hidrorumo[9]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Three hydroelectric power plants are located on São Tomé Island: Guégué, Contador and Agostinho Neto. In Príncipe Island there is one hydroelectric power plant, Papagaio. The Guégué, Agostinho Neto and Papagaio power plants belong to the company Hidroeléctrica STP, a partnership between private investors (60 per cent) and the State of Sao Tome and Principe, EMAE (40 per cent). The Contador power plant (2 x 1 MW) is classified as small size and Guégué (0.32 MW), Papagaio (0.128 MW) and Agostinho Neto (0.128 MW) are classified as mini-hydropower plants.[7]

A study performed by HIDRORUMO1 shows that there are 34 potentially exploitable sites. 31 of these sites are located on 8 main rivers in São Tomé Island and 3 are located on 3 watercourses in Príncipe Island. The assessed total installed capacity of these 34 sites is 61 MW, which corresponds to a total production of electrical energy of 244 GWh per year. Adding the existing hydroelectric power plants to those referred above, the installed capacity would reach 63.6 MW, with electricity generation of 251 GWh per year.[5]

Currently there are several projects in development: Rio Iô Grande I (6.9 MW) and Rio Iô Grande II (4 MW), Rio Abade II (2.4 MW), Rio Abade III (1.8 MW), Manuel Jorge II (0.8 MW) and Manuel Jorge III (0.9 MW). The works have not begun due to a lack of financing.

Approximately 92 per cent of all projects have been funded by the State General Budget through the Public Investment Programme.[9] However, there is no National Plan for Renewable Energy sector, which is a major setback for development. In order to encourage private investment, the United Nations Development Programme (UNDP) has intentions to invest US$1 million as a bank guarantee to the private investors, for the construction of mini-hydropower plants in São Tomé Island and in the Autonomous Region of Príncipe.[9]

Renewable energy policy

Sao Tome and Principe is rich in renewable energy (RE) sources, namely hydro, solar and biomass, with wind energy having a lower capacity. However, studies must be carried out in order to define the real potential. In the ambit of Countries Contribution for Climate Change, the national goal is to increase RE to 47 per cent out of the total electricity mix between 2020-2030.[11] The general plans are as follows: 1 MW for mini-hydropower plants isolated from the national grid, 4 MW to 9 MW for additional SHP plants integrated in the national grid, 12 MW of solar photovoltaic power plants, isolated, but connected to the national grid.

Barriers to SHP development

The main problems for development of SHP are:

- Lack of an Energy Directive Plan with clear objectives and targets;
- Limited loans for the development of hydropower projects and respective design;
- Limitations of the State General Budget to create a business-friendly environment that supports investment in the construction of small and mini-hydropower plants;
- Limited regulations for the exploitation of hydropower plants;
- Limited tax and tributary incentives for the investor;
- Limited expertise, knowledge and professional training for the technical staff suitable for the sector;
- Limited access to the actual and more efficient technologies;
- Small size of the market in comparison with return on investment.

1.3 Northern Africa

Pirran Driver, Nippon Koei LAC Tunisia

Introduction to the region

The Northern Africa region, as defined by the United Nations Statistics Division, comprises the territories of Western Sahara, Morocco, Algeria, Tunisia, Libya, Egypt and Sudan (listed from west to east).[1]

Due to the political situation in Western Sahara and Libya, the present report has been unable to gather sufficient information to warrant inclusion of reports. It is, however, understood that neither has any installed hydropower schemes, whether large or small.

Therefore, this report covers five countries of the region that have small hydropower (SHP) plants: Algeria, Egypt, Morocco, Sudan and Tunisia. An overview of the countries is provided in Table 1.

With the exception of the westernmost and easternmost areas (Western Sahara and Sudan), the region has broadly similar climatic and geographic conditions, with a northern coastal strip enjoying a Mediterranean climate, giving way to more arid conditions and then desert further south. Morocco, Algeria and Tunisia also include the Atlas mountain range, which causes cooler temperatures and increased precipitation. Western Sahara has a hot desert climate, whilst Sudan has a hot desert climate in the north and an equatorial climate in the south.[2]

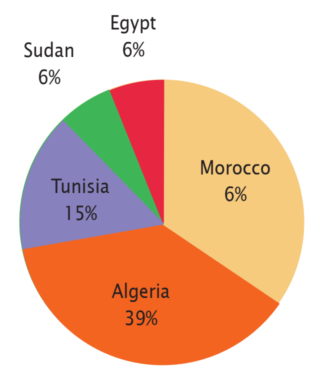
Most of the countries in the region enjoy high levels (more than 95 per cent) of electrification. Only Sudan has a lower electrification rate (approximately 30 per cent), more commonly encountered in the Sub-Saharan region. No data exists for Western Sahara. Algeria, Libya and Sudan have significant hydrocarbon resources and are largely energy self-sufficient.[3] Egypt also has significant hydrocarbon resources, yet has been a net energy importer for a number of years. Tunisia has some minor gas and oil resources, but remains a net importer. Morocco and Western Sahara have no known exploitable hydrocarbon resources.

The lack of sufficient hydrocarbon resources in some of the countries and the desire to diversify has led governments in the region to seek alternative energy sources. However, the focus in recent years has favoured the development of wind and solar power over both small and large hydropower.

As will be described more fully later in this introduction and within the country reports themselves, the climate, geography, hydrology and political situation of the region as a whole is not presently conducive to significant SHP development.

FIGURE 1

Share of regional installed capacity of SHP by country



Source: *WSHPDR 2016*[12]

TABLE 1

Overview of countries in Northern Africa (+/–% change from 2013)

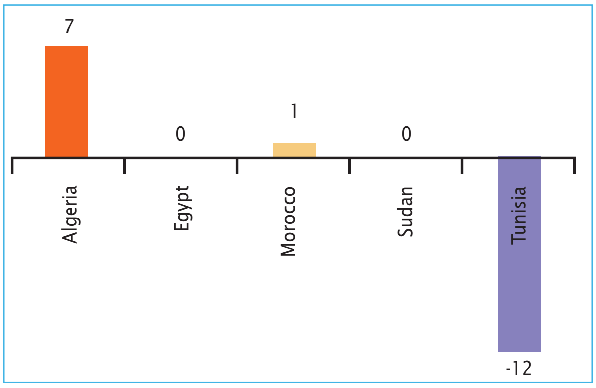
Country	Total Population (million)	Rural Population (%)	Electricity Access (%)	Installed Capacity (MW)	Electricity Generation (GWh/year)	Hydropower Capacity (MW)	Hydropower Generation (GWh/year)
Algeria	38.81 (+3%)	29.9 (-26pp)	99.3 (0pp)	15,100 (+33%)	57,397 (+27%)	269 (-4.6%)	622 (+11%)
Egypt	88.49 (+5%)	57.6 (+0.6pp)	99.6 (0pp)	32,015 (+29%)	168,050 (+21%)	2,800 (0%)	13,352 (+4%)
Morocco	32.95 (+2%)	41.5 (-1.5pp)	98.9 (+0.9pp)	8,159 (+29%)	28,082 (+23%)	1,770 (+4%)	2,033 (-44%)
Sudan	36.11 (+5%)	72 (+12pp)	60 (+24.1pp)	3,327 (+24%)*	13,133 (-13%)	1,593 (0%)*	8,405 (+16%)
Tunisia	10.98 (+2%)	33 (0pp)	99.5 (0pp)	4,334 (+20%)	17,672 (+19%)	62 (-11%)	160 (-46%)
Total	**207.3 (+4%)**	—	—	**62,935 (+29%)**	**284,334 (+26%)**	**6,494 (-0.8%)**	**24,572 (-0.1%)**

Sources: Various[4,5,6,7,8,9,10]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting
Note: An asterisk (*) indicates the comparison is made to the data in the country report of *WSHPDR 2013* and not the regional summary.

The total installed SHP capacity of the region in *World Small Hydropower Development Report* (*WSHPDR*) *2016* is around 112 MW, 3 MW less than what was documented in *WSHPDR 2013*. This decrease is mainly due to access to more accurate data, particularly on Tunisia.

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for Northern Africa



Sources: *WSHPDR 2013*,[10] *WSHPDR 2016*[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative or positive net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting; Algeria and Tunisia net changes due to access to more accurate data and not indicative of actual changes in installed capacities.

Small hydropower definition

Of the countries in the region, Algeria and Tunisia have a formal definition of SHP as any scheme at or below an installed capacity of 10 MW.[10] Sudan classifies hydropower into four categories: micro (< 50 kW), mini (50 kW-500 kW), small (500 kW-5 MW) and large (> 5 MW). Due to a lack of national definitions in the region, for the purposes of this report, the authors have adopted the definition used by the International Centre on Small Hydropower. This definition is the same as the Tunisian definition: any scheme with an installed capacity of at or below 10 MW.[11]

TABLE 2

Classification of small hydropower in Northern Africa

Country	Small	Mini	Micro	Pico
Algeria	5-10 MW	—	100 kW-5 MW	< 100 kW
Egypt	—	—	—	—
Morocco	2-10 MW	500 kW-2 MW	20 kW-500 kW	< 20 kW
Sudan	500 kW-5 MW	50 kW-500 KW	< 50 kW	—
Tunisia	Up to 10 MW	—	—	—

Source: *WSHPDR 2016*[12]

Regional SHP overview and renewable energy policy

All five countries covered in this report are host to SHP schemes, but it cannot be considered a significant sector in the region. As shown in Table 1, hydropower in general (i.e. both large and small) remains a minority sector when compared to total electricity generation in the region (8.6 per cent). Morocco has the highest hydropower share at 21 per cent of total installed capacity (but only around 7 per cent of production), with SHP accounting for just 0.5 per cent of total capacity. The remaining countries all have a rather low hydropower share, with negligible contributions from SHP schemes.

Overall, there has been little change to the SHP sector in the Northern Africa region since *WSHPDR 2013*. The country reports that follow will elaborate on the progress made since 2013. However, little change has occurred in the region in regards to energy projects or policies. The installed SHP capacity in the region remains low, and with the exception of Morocco and Sudan, there is little indication that policymakers have SHP schemes on their agendas.

TABLE 3

Small hydropower in Northern Africa (+/–% change from 2013)

Country	Potential (MW)	Installed capacity (MW)
Algeria	N/A	42.1 (+6.8%)
Egypt	51.7 (+62%)	6.8 (0%)
Morocco	54 (0%)	38.4 (+3%)
Sudan	63.2 (+85%)	7.2 (+0%)
Tunisia	56 (-)	17.0 (–41%)
Total	**224.9 (+22%)**	**111.5 (–3%)**

Source: *WSHPDR 2016*[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative or positive net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting; Algeria and Tunisia net changes due to access to more accurate data and not indicative of actual changes in installed capacities.

Barriers to small hydropower development

As will be evident to readers of the country reports who are following this summary, the climatic, geomorphologic and hydrological conditions of the region are largely desert and steppe-based, therefore not ideal for hydropower development. While there are occasional major rivers suitable for large hydropower (the Nile being the prime example), there is a significant lack of smaller perennial rivers and other water sources suitable for the development of SHP schemes.

Although the countries of the region generally have high economic burdens resulting from extensive energy subsidies, there appears to be a lack of interest on behalf of regional governments to develop the hydropower sector (specifically, the SHP sector). Governments are instead seeking to facilitate investments in nuclear, solar and wind power as a more viable means to achieving their generally ambitious alternative energy expansion plans. Sudan is the principal country in the region that is currently engaged in significant hydropower development, but it is focusing on larger schemes. Morocco, the sole country in the region without substantial oil reserves, is also the only country in the region with any meaningful policy for development of SHP. Since 2010, Morocco has been embarking upon a programme of identification and development of micro-hydropower schemes. To date, 200 potential sites have been identified, and the first scheme (Meknes-Tafilalet) is now operational. Three further SHP schemes, with a total capacity of 15.13 MW, are currently under construction.

In addition to the unfavourable geo-climatic conditions and the regional governments' focus on alternative energies, a number of other key barriers to the development of SHP have been reported by the country summary authors. These include:

- Low electricity tariffs, generally due to extensive subsidies;
- Limited financial and other incentives encouraging private sector developments;
- Limited feasibility/site-selection studies;
- Poor policy development, planning, and budgeting;
- Institutional weaknesses (often linked to recent or ongoing civil turmoil);
- Favourable conditions prevail for development of wind and solar technologies;
- Limited technical capability and skills;
- Limited equipment/manufacturing capability;

It is hoped that in the coming years, regional governments will become more interested in SHP development. While solar and wind technologies undoubtedly offer the large capacity gains that regional governments are currently seeking, SHP offers a unique proposition of low cost renewable energy without the high land-take, landscape and other negative impacts that are commonly associated with solar and wind power. It would therefore offer governments in the region a more balanced spread of energy investments.

1.3.1 Algeria

Denise Tulcidas and Marcis Galauska, International Center on Small Hydro Power (ICSHP)

Key facts

Population	38,813,722[1]
Area	2,381,741 km[2]
Climate	Climate is temperate in the coastal region with abundant rainfall, in winters temperatures vary from 10°C to 12°C and summers vary from 24°C to 26°C. Winters are colder inland (with occasional snow), temperatures range from 4°C to 6°C. Temperatures in the summer range from 26°C to 28°C. In the desert region, winds are violent and temperatures are extreme, varying from −10°C at their coldest to 49°C at their warmest.[2] Sirocco is a hot, dust/sand-laden wind that hits the country particularly in summer.[2]
Topography	Divided by four distinct regions, the Mediterranean or Tell in the northern coastal area is formed of hills and valleys. The High Plateau consists of undulating, steppe-like plains and shallow salt lakes called shots, the Sahara atlas consists of three mountain chains containing pasturelands and the Sahara desert is a flatland covered with gravel and dune chains. The highest point is Mount Tahat (3,003 metres) in the Ahaggar Range of the Sahara. Most of the rivers flow irregularly and only the main rivers of the Tell have water all year.[2]
Rain pattern	Rainfall is abundant in the coastal region, with 38-69 cm per year. In the eastern region, it is up to 100 cm (excluding the area around Oran). Heavy rains can bring more than 3.8 cm within 24 hours causing floods, though these are often quickly evaporated. In the interior of the country, precipitation is registered from September to December. In the desert region, the precipitation is sparse and irregular.[2]
General dissipation of rivers and other water sources	The rivers 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, is 725 km and the flow is irregular, with the longest continuous flow being from November to March.[2]

Electricity sector overview

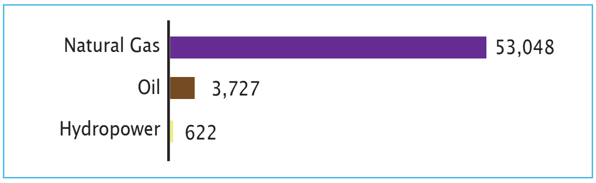
The energy sector in Algeria is dominated by the use of gas and oil. The country is a leading natural gas producer (one of the largest natural gas suppliers to Europe) and is among the top three oil producers in Africa, therefore fossil fuels account for almost all of the primary energy consumption.[8]

According to the International Energy Agency, natural gas constitutes 92 per cent of power generation in Algeria. The country exports it through gas pipelines (to Italy via Tunisia and to Spain via Morocco and the Mediterranean Sea) and relies on it for domestic consumption. The Government is planning to reduce the dependence on natural gas and is introducing more renewable energy (RE) projects in the power sector. The state electricity and gas utility company, Soneglaz, has signed contracts for solar and wind farm projects.[10]

In 2012, electricity generation in Algeria was 57,397 GWh. Natural gas constituted 53,048 GWh (92.42 per cent), oil constituted 3,727 GWh (6.49 per cent) and hydropower 622 GWh (1.08 per cent) (Figure 1).[3] The total installed electricity capacity grew by almost 18 per cent in the end of 2013, reaching 15.1 GW, as compared to 12.9 GW at the end of 2012 and 11.4 GW at the end of 2011. The electrification rate in Algeria is high and more than 99 per cent of the population is connected to electricity.[5]

FIGURE 1

Electricity generation in Algeria by source (GWh)



Source: International Energy Agency (IEA)[3]

In 2012, the net electricity consumption was 44 billion kWh and peak demand is expected to grow to 20 GW by 2017. Sonelgaz is projecting to spend US$7.6 billion (2014-2017) to increase generation capacity, adding more than 12 GW by 2017-2018.[10]

The country's economy is dependent on the energy sector. Domestic prices for oil products (diesel, gasoline, and liquefied petroleum gas) and natural gas are very low and the country has the second-cheapest domestic price for natural gas in Africa. Retail prices in Algeria have not changed since 2005 and are now below operational costs. It is estimated that the cost of the implicit subsidies on oil products and natural gas amounted to US$22.2 billion in 2012, or 10.7 per cent of the country's Gross Domestic Product (GDP). The hydrocarbon sector accounts for almost 30 per cent of the country's GDP, more than 95 per cent of export earnings, and 60 per cent of budget revenues.[10]

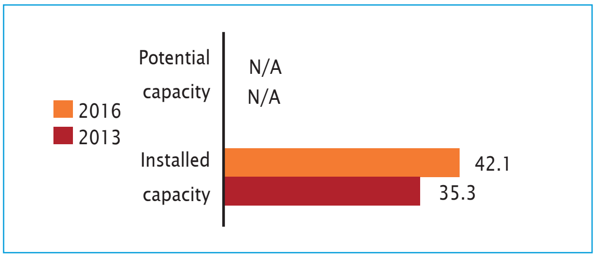
According to the Algerian Agency for the Promotion and Rationalization of the Use of Energy (APRUE), energy consumption is expected to increase by 81 per cent from 2003 to 2020 (an annual growth rate of about 3.5 per cent) due to urbanization, an increasing standard of living and the development of the service sector. The residential and service sectors have the highest potential for increasing energy efficiency. The annual housing consumption is 632 MJ/m^2. Heating takes the largest share (46 per cent), followed by cooking (22 per cent), hot water (13 per cent) and electrical appliances (19 per cent).[11]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Algeria is defined as any plant with a capacity of 5 MW to 10 MW. Algeria also defines micro hydropower as any plant with a capacity of 100 kW to 5 MW and pico hydropower as any plant less than 100 kW.[18] For the purposes of this report, SHP will include all plants with an installed capacity up to 10 MW. The installed capacity of SHP is 42.12 MW, while its potential capacity is not available.[15] When compared with *World Small Hydropower Development Report* (*WSHPDR*) *2013*, the data indicates an increase in installed capacity. However, this is due to access to more accurate data and an actual increase was unlikely (Figure 2). It should be noted that operational capacity is likely to be lower and continue to decrease, as discussed below.

FIGURE 2

Small hydropower capacities 2013-2016 in Algeria (MW)



Sources: *WSHPDR 2013*,[14] Ministry of Energy and Mines[15]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The SHP potential in Algeria is unknown but it is considered to be low. The hydropower resources decrease from north to south where precipitation is limited. Although flows are estimated to be about 65 billion m^3, the restricted rainfall and rapid evaporation are the major constraints and it is estimated that only 25 billion m^3 (including about two-thirds for surface resources) can be used, as has been shown in recent evaluations. According to the Ministry of Energy and Mining, 103 dam sites have been recorded and more than 50 dams are in operation.[9]

Algeria has approximately 269 MW of installed hydropower capacity (622 GWh/year) with plants of capacities between 1 MW and 100 MW. However, this energy source only plays a marginal role due to limited precipitation and high evaporation. Following the SHP definition of 10 MW upper limit capacity, there are at least 42.12 MW of SHP installed (Table 1).[4] Approximately 13 per cent of the total hydropower consists of SHP.

In the period between 1971 and 2010, the average contribution percentage of hydropower to the total electricity production was 4 per cent. The highest value was registered in 1973 (26.8 per cent) and the lowest value in 2002 (2 per cent).[5] Hydropower is expected to account for 1.2-1.3 per cent of electricity generation by 2025.[6]

TABLE 1

Installed hydropower capacity in Algeria (MW)

Sites	Installed capacity (MW)
Mansouria	100.0
Darguina	71.5
IghilEmda	24.0
Erraguene	16.0
OuedFodda	15.6
SoukelDjemaa	8.1
Ghrib	7.0
Gouriet	6.4
Bouhanifia	5.7
TiziMeden	4.5
Tessala	4.2
Beni Behde	3.5
Ighzernchebel	2.7

Source: Ministry of Energy and Mining[15]

However, in 2014, the Government declared its intention to halt operation of electricity production from hydroelectric dams and devote existing dam resources to irrigation and drinking water supply. The Ministry of Energy and Mining (MEM) stated that the needs of the population for water supply outweighed the electricity generated by the dams.[16] This sentiment was also echoed in the New National Programme for Renewable Energy Development (2015-2030), which excludes hydropower from its roadmap for RE development.[17]

Renewable energy policy

Algeria has a high potential for RE, mainly solar and wind. In order to expand the use of these sources, the Government launched a programme for Renewable Energy and Energy Efficiency for the period between 2011-2030. The objective of the programme is to generate 22,000 MW of power from renewable sources, 12,000 MW for domestic consumption and 10,000 MW for export. This is 40 per cent of the national electricity generation.[12,9]

Algeria has one of the highest solar potentials in the world, estimated at 13.9 TWh per year. The Government plans to launch several photovoltaic solar projects with a capacity of 800 MWp by 2020 and more projects with a capacity of 200 MWp per year from 2021 to 2030. Four solar thermal power plants with a capacity of 1,200 MW will be in service from 2016 to 2020, with more planned at 500 MW per year until 2023, as well as 600 MW per year until 2030.[9]

The wind potential in the country is 35 TWh per year. Two wind farms with a capacity of 20 MW were developed during 2014 and 2015. Studies are being conducted on other projects with a capacity of 1,700 MW to be implemented from 2016 to 2030. The country also has a potential for biomass energy. According to the National Cadastre for Generation of Solid Waste, the annual generation of municipal wastes in Algeria is more than 10 million tons and solid wastes are usually disposed in open dumps or burnt.[12,9]

The Government has created four institutions responsible for the alternative energies sector. These are:

- The Renewable Energy Development Centre, which is responsible for the evaluation of RE potential
- New Energy Algeria, which is responsible for the development and production of solar and other renewable energies
- The National Agency for Promotion and Rationalization of Energy Use, which is central to the implementation of the National Energy Efficiency Programme, responsible for information, communication and management training
- The National Energy Efficiency Fund of Algeria, created to finance energy efficiency investments of the National Energy Efficiency Agency and its projects under the National Energy Efficiency Programme[11]

Barriers to small hydropower development

Climatic and geographical conditions are the principal constraint for SHP development in Algeria. These include:

- Limited rainfall in the south of the country;
- Hydro concentration in limited spaces;
- High levels of evaporation and quick evacuation to the sea are major barriers.

These factors discourage potential investors and limit funding availability, forcing the Government to focus on other alternative energies such as solar and wind. This is reflected in the MEM's Renewable Energy and Energy Efficiency National Programme, where hydropower was excluded since it is not seen as a viable and attractive sector.[9,13]

1.3.2 Egypt

Ibrahim Ragab Mohamed Teaima, Ministry of Water Resources and Irrigation

Key facts

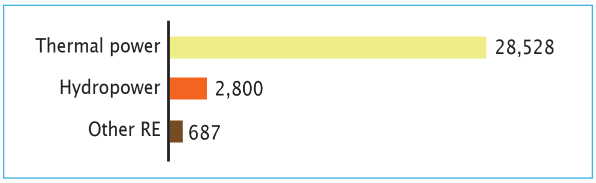
Population	88,487,396[1]
Area	1,001,450 km[2]
Climate	Throughout Egypt, days are commonly warm or hot and nights are cool. There are two seasons, a mild winter from November to April and a hot summer from May to October. The differences between the seasons are noted through the differences in daytime temperatures and changing winds. The mean daily temperature changes from 27.6C in July to 13.6C in January.[2]
Topography	Vast desert plateau dissected by the Nile Valley and Delta with the Sinai Peninsula in the east which connects Africa to the Asian continent. The Nile Delta is a broad, alluvial land, sloping to the sea for 160 km. South along the Nile River, most of the country (known as Upper Egypt) is a tableland rising to approximately 460 metres. Altitude ranges from 133 metres below sea level in the Libyan Desert to 2,629 metres above in the Sinai Peninsula.[3]
Rain pattern	Egypt receives less than 80 mm of precipitation annually in most areas. The coastal areas are the exception, where the precipitation reaches 200 mm.[3]
General dissipation of rivers and other water sources	The country's main river is the Nile, widely regarded as the longest river in the world at 6,853 km. The Nile enters Egypt over the Sudanese border in the south and has no non-seasonal tributaries for the entire length of the country. Before flowing into the Mediterranean, the river splits off into a number of distributaries in the Nile Delta. Other important water systems include the Suez canal, the Alexandria-Cairo Waterway and Lake Nasser.[3]

Electricity sector overview

In 2015, the United states Department of Energy reported that Egypt had a total installed capacity of 31,450 MW.[7] However, the Ministry of Electricity and Renewable Energy reported in 2014 that there was an installed capacity of 32,015 MW, of which 26,480 MW was from thermal (gas, steam, and combined cycle plants), 2,800 MW was from hydropower plants and 687 MW was from other renewable sources, mainly solar and wind. A large percentage of this capacity came from thermal power, which accounted for almost 83 per cent. Hydropower accounted for approximately 9 per cent, while the other renewable sources accounted for the remaining 6 per cent (Figure 1).[4]

FIGURE 1

Installed electricity capacity in Egypt by source (MW)

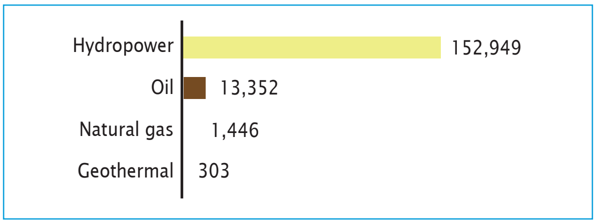


Source: EEHC[4]

From 2013 to 2014, the total generation was 168,050 GWh.[4]. The private sector's build-own-operate-transfer plants (BOOTs), and hydropower were both at 8 per cent, with other renewable sources making up less than 1 per cent. Additionally, other sources that contribute to the electricity generation include isolated plants and energy purchased from independent power producers (IPPs). However, they provided a negligible amount of the total energy generated (Figure 2).[4]

FIGURE 2

Annual electricity generation in Egypt by source (GWh)



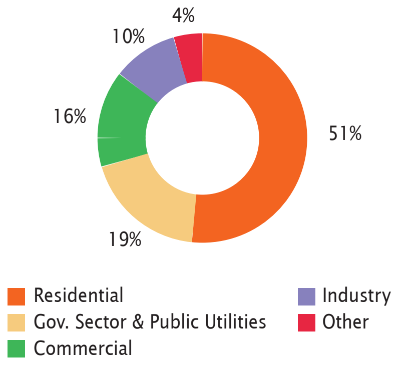
Source: EEHC[4]

In 2013, 120,826 GWh of electricity was sold through distribution companies to low and medium voltage end users. More than half of this was sold to residential consumers, while 21 per cent and 16 per cent were sold to industrial consumers and the government sector respectively. The commercial sector accounted for only 3 per cent of sales (Figure 3).[4]

The Egyptian energy sector is a mixture of both state-owned and private companies in the form of IPPs and privately owned BOOTs. Together, the state-owned and private companies allow Egypt to have an overall electrification rate of at least 99.6 per cent. The last recorded statistic comes from the World Bank Data Bank in 2010. More recent estimates have been made by outside energy organizations, but the Government has not released an electrification rate since 2010.[16]

FIGURE 3

Energy sold by sector in Egypt (medium and low voltage) (%)



Source: EEHC[4]

The state-owned and operated Egyptian Electricity Holding Company (EEHC) coordinates, supervises and monitors the activities of its subsidiary companies, which are responsible for generation, transmission and distribution. In terms of generation, the 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, based upon region.[5] The Ministry of Electricity and Energy is the principal policy maker and supervises all activities related to energy projects, as well as suggests electricity prices and publishes data and statistics relating to electricity production. The New and Renewable Energy Authority (NREA) was established in 1986 to promote both renewable sources of energy and energy efficiency, as well as efforts to develop and introduce renewable energy (RE) technologies on a commercial scale. The Egyptian Electric Utility and Consumer Protection Regulatory Agency (EgyptERA) was established in 1997 to balance the interests of electricity producers, electricity providers and end users. It is considered the industry watchdog, responsible for licensing the construction and operation of electricity generation, transmission and distribution facilities, as well as for electricity trading. In 2012 and 2013, the EEHC accounted for more than 90 per cent of total electricity generation in the country, with BOOTs providing 8.66 per cent and IPPs providing 0.02 per cent.[5]

In 2013 and 2014, the grid consisted of 44,220 km of transmission lines and cables ranging from 33 kV to 500 kV. The grid is subdivided into six geographical zones, namely Cairo, Canal, Delta, Alexandria and West Delta, Middle Egypt and Upper Egypt.

TABLE 1

Tariff structure in Egypt

Sector type	**Energy price (Egyptian pounds (US$) per kWh)***
Power service on extra high voltage (Pt/kWh)	
Kima	0.047 (0.007)
Metro-Ramsis	0.079 (0.013)
Somed (Arabian Company for Petrol Pipes)	0.316 (0.050)
Other Consumers	0.150 (0.024)
Power service on high voltage (Pt/kWh)	
Metro-Toura	0.131 (0.021)
Other Consumers	0.182 (0.029)
Power service on medium & low voltage	
More than 500 KW	
Demand charge (LE/kW-month)	0.100 (0.016)
Energy rates (Pt/kWh)	0.250 (0.04)
Up to 500 kW	
(a) Agriculture (Pt/kWh)	0.112 (0.018)
Annual charge per fedan for irrigation by groups (LE/Fedan)	1.352 (0.214)
(b) Other purposes (Pt/kWh)	0.290 (0.046)
4-Residential	
First 50 kWh monthly	0.050 (0.008)
51-200 kWh monthly	0.120 (0.019)
201-350 kWh monthly	0.190 (0.03)
351-650 kWh monthly	0.290 (0.046)
651-1,000 kWh monthly	0.530 (0.084)
More than 1,000 kWh monthly	0.670 (0.106)
Commercial	
Description price (Pt/kWh)	
First 100 kWh monthly	0.270 (0.043)
101-250 kWh monthly	0.410 (0.065)
251-600 kWh monthly	0.530 (0.084)
601-1,000 kWh monthly	0.670 (0.106)
More than 1,000 kWh monthly	0.720 (0.114)
Public lighting	0.475 (0.075)

Source: EgyptERA[6]
Note: Prices are based on a power factor of 0.9.

The country's entire territory is covered by the electrical network. However, there are 30 power plants, mainly gas and diesel, as well as one 5 MW wind farm, that are not connected to the grid and mainly installed in remote areas to provide electricity to tourist sites. The Egyptian electrical grid is interconnected with Libya, Jordan, Syria and Lebanon with ongoing studies for interconnections with Saudi Arabia, Sudan, the Democratic Republic of the Congo, the Eastern Nile Basin (Sudan and Ethiopia) and Greece.[2]

A combination of increasing demand, decreasing production and high subsidies for fuel have put a strain on the Egyptian energy sector and led to an enormous public deficit. As of June 2014, Egypt owed US$7.5 billion to foreign oil and gas companies.[7] In order to cover the growing demand, the five-year plan for 2012-2017 foresees an investment of approximately 103 billion Egyptian Pounds (US$16 billion) in the construction of new power stations, substations, transmission and distribution networks and the renovation of existing networks.

Alongside the NREA, the EEHC hopes to add 2,980 MW of capacity from renewable sources as part of the five-year plan for 2012-2017, and to encourage the private sector to take part in the implementation of these projects. In addition, the National Energy Efficiency Action Plan has been implemented which aims to increase efficiency across a range of sectors as well as to launch a media awareness campaign.[4]

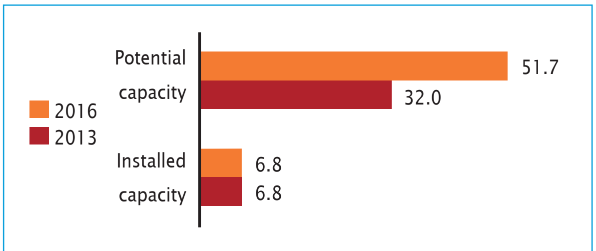
Electricity tariffs in Egypt are some of the lowest in the world with government subsidies for the residential sector totalling 13.2 billion Egyptian Pounds (US$2 billion) in 2012 and 2013. In 2013 and 2014, total energy subsidies across all sectors reached 144 billion Egyptian Pounds (US$23 billion) and, as of July 2014, the Government sold electricity for less than half its production cost. Since 2012, subsidies have been slowly reduced as part of a five-year plan that will see energy prices doubled by 2017.[8] Table 1 provides tariffs by sector.[7]

Small hydropower overview and potential

There is no official definition of small hydropower (SHP) in Egypt. However, this report assumes a definition of 10 MW or less. There is an estimated installed SHP capacity of approximately 6.8 MW with an estimated total potential capacity of almost 52 MW, indicating that 13.2 per cent has been developed.[9,10,11,12] Compared to *World Small Hydropower Development Report* (*WSHPDR*) *2013*, installed capacity has remained unchanged, but the estimated potential has increased by more than 60 per cent (Figure 4).[13]

FIGURE 4

Small hydropower capacities 2013-2016 in Egypt (MW)



Sources: Various[6,7,9,10,13]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The country's Hydro Power Plants Executive Authority is responsible for the study, execution and development of hydropower projects. Current installed capacity comes from four operational plants, Small Naga Hamadi, El Lahun, El Faiyum and El Azabthree. Three plants, with a total capacity of 6.6 MW, have been planned. Feasibility studies estimate a potential additional capacity of approximately 45 MW (Table 2).

TABLE 2

Installed and potential small hydropower plants

Plant name	Capacity (MW)
Operational	
Small Naga Hamadi	4.5
El Lahun	0.8
El Faiyum	0.8
El Azab	0.7
Planned	
Zefta	5.5
El Sekka/El Hadeed	0.55
Wadi El Rayan	0.55
Potential small hydropower sites	
Damitta spans	6.5
Rashed spans	4.6
Assiut Regulator	3
TawfikiRayah	2.45
BeheriRayah	2.2
AbbasiRayah	1.85
Edfina Barrage	1.85
Sharkawia Canal	1.85
MenoufiRayah	1.8
Ibrahimia Canal Intake	1.55
Tawflky Intake	1.2
Yosfly sea Intake	1.2
Adfena canal	1
Apassy Intake	1
BahrYousef Canal	1
El Mokhtalat	1
Elkarneen Intake	0.75
Gamagra spans	0.75
Lahawan spans	0.6
Mansoma Intake	0.5
Bagoria Intake	0.4
Elkalabla canal	0.38
Elnasary Intake	0.38
Habab weir	0.18
Asfon canal	0.15
Elsekaelhadid spans	0.15
Total	**51.69**

Sources: Various[6,7,9,10]

There are currently five large hydropower plants in operation, all located on the River Nile. Total installed capacity is approximately 2,800 MW, of which 2,100 MW is found in the Aswan High Dam. SHP plants contribute less than 2 per cent of the total capacity. There is a general consensus that at least 85 per cent of the country's potential hydropower has already been developed and does not feature prominently in the Government's plans for RE development.[14] A feed-in tariff scheme introduced in 2014 for RE sources does not include hydropower (see below).

Renewable energy policy

In February 2008, the Government adopted the New National Renewable Energy Strategy with a target of 20 per cent of the country's total annual electricity generation to come from renewable resources by 2020. Wind energy is seen as key to achieving this with 12 per cent of total capacity (7,200 MW installed capacity) expected to come from wind farms alone.[15] Furthermore, 6 per cent is expected to be achieved from existing hydropower structures and 2 per cent from other renewable sources, specifically by developing solar resources.[2]

One-third of the planned capacity will be state-owned projects financed through public investments by the NREA in cooperation with international financing institutions. Two-thirds are intended to be private sector projects, supported by policies structured in two phases:

- Phase 1 will adopt competitive bids through issuing tenders requesting the private sector to supply electricity from RE sources.
- In Phase 2, a feed-in tariff will be implemented, in particular for medium- and small-size projects.[12]

Incentives for investors include:

- Approving private sector participation through competitive tender and bilateral agreements.
- Reducing project risks through signing long-term, Government guaranteed, Power Purchase Agreements for 20-25 years.
- The selling price for energy generated from RE projects will be in foreign currency in addition to a portion, covering operation and maintenance costs, in local currency.
- Investors will be issued and can sell certificates of emission reduction.
- Evaluation criteria for tenders of RE projects will give privilege for local components.
- All RE equipment and spare parts are exempt from customs duties and sales taxes.

In September 2014, the Government approved the issuance of feed-in tariffs for solar PV and wind projects with fixed feed-in tariffs over 25 years for PV and over 20 years for wind. These range from US$0.046 for wind farms in the highest operating hours category to US$0.143 for solar PV plants between 20 MW to 50 MW installed capacity. These tariffs will be adjusted as soon as the following ceilings are reached: 300 MW of small PV (< 500 kW), 2,000 MW of medium PV (500 kW-50 MW) and 2,000 MW of wind. Installations from 500 kW and above, including both the medium and high voltage connected installations, are defined in United States dollars. Although payment will be offered in Egyptian Pounds, the Government of Egypt bears the exchange rate risk. The feed-in tariff scheme is complemented by Law 203/2014 of 22 December 2014 where the EETC and the local distribution companies are obliged to connect a RE project to the grid. While the connections are borne by the producer, the Government funds any extension of the grid. They are also obliged to purchase the electricity generated by qualifying projects and, if this is not feasible, compensate the producer.

Barriers to small hydropower development

A key barrier to SHP development is the lack of government interest, while favouring the pursuit of a RE policy based largely on wind and solar energy. Without similar financial incentives given to SHP, it will prove difficult to attract investment over more favourable options. This lack of interest stems from a general consensus that some 85 per cent of the Nile River has already been developed for hydropower. This means that the NREA stands to make better marginal gains and financial support by looking into other untapped non-hydro resources. Nonetheless, this assessment is largely based on a perspective from large hydropower projects. With more accurate studies on SHP potential, it is possible that significant undeveloped potential may still exist. A general barrier to renewable development in the past has been the low cost of electricity backed by government subsidies. However, since 2012, these subsidies have been slowly phased out with the expectation that they will be fully removed by 2017.

1.3.3 Morocco

Tom Rennell, International Center on Small Hydro Power (ICSHP); Karim Choukri, University "Hassan 1er" Settat Morocco

Key facts

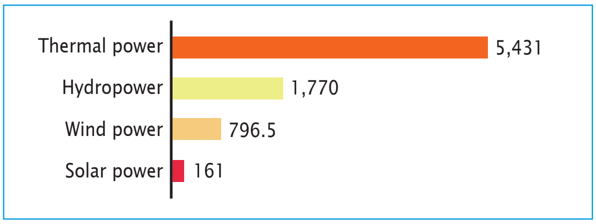
Population	32,950,000[1]
Area	710,850 km[2]
Climate	Morocco's climate varies according to region and the season. The more outstanding climate is tropical, with temperatures as high as 35°C. However, in the Sahara region of the country, the temperature can also drop to 5°C. The coastal region has a Mediterranean climate and is tempered by the south-west trade winds. The more inland region has a hotter, drier, continental climate. In the south of the country, the Sahara region, the weather is very hot and arid throughout most of the year,though temperatures can drop dramatically at night. This is especially the case in the months of December and January.[1]
Topography	The Atlas mountain range, rising to over 3,000 metres, runs through the middle of Morocco. A fertile coastal plain lies to the north and the west, along the Mediterranean, while semiarid grasslands that merge with the Sahara Desert are found along the south-eastern borders of the country. The highest point is Mount Toubkal at 4,165 metres and the lowest point is Sebkha Tah at 5 metres below sea level.[1]
Rain pattern	Morocco has spatial and temporal variability rainfall. For example, the north-west has, on average, more rain than the rest of the country, but even there the average annual rainfall varies considerably. Annual precipitation can reach more than 800 mm on the reliefs, while not exceeding 300 mm over the surrounding plains. Moreover, annual precipitation in Morocco is irregular from one year to another.[1]
General dissipation of rivers and other water sources	Morocco has one of the most extensive river systems in north Africa. Rivers flowing south or westward into the Atlantic Ocean include the Rebia (555 km), Sebou (500 km), Bouregreg (250 km), Tensift (270 km), and Drâa (1,200 km). Marking part of the border with Algeria, the Drâa is the longest river in the country, although it is seasonal and occasionally runs dry. The Ziz (282 km) flows south into the Sahara desert out of the Atlas and the Moulouya (560 km) flows north-east from the Atlas to the Mediterranean.[1]

Electricity sector overview

As of the end of 2015, the total installed capacity in Morocco was 8,158.5 MW compared to 7,994 MW in 2014, 7,242 MW in 2013 and 6,692 MW in 2012. Hydropower, including pumped storage, contributed approximately 22 per cent, wind and solar constituted 12 per cent and the remainder came from fossil fuel-based power plants including coal, gas and diesel (Figure 1).[12]

FIGURE 1

Installed electricity capacity in Morocco by source (MW)

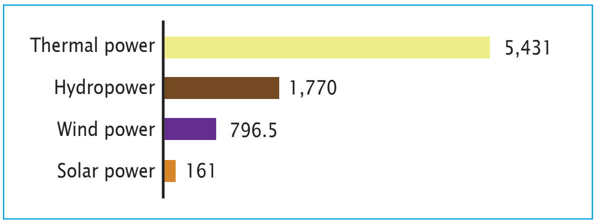


Source: ONEE[12]

In 2014, the total electricity generation was 28,081.5 GWh, of which approximately 85 per cent came from fossil fuel-based power plants, 7 per cent from hydropower (including pumped storage) and 7 per cent from wind farms and other renewable energies.[3] Less than 1 per cent came from other sources, including small privately run plants (Figure 2).

FIGURE 2

Annual electricity generation in Morocco by source (GWh)

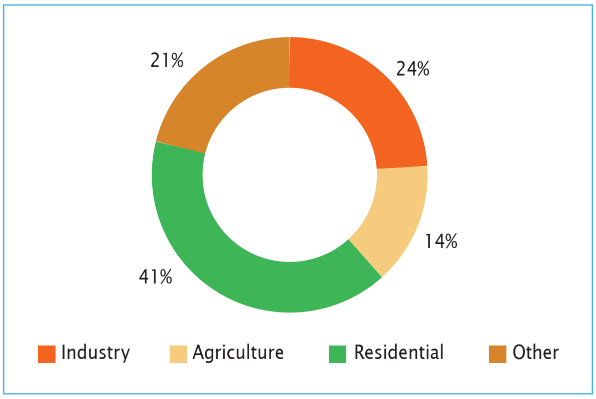


Source: ONEE[3]

Over the last decade, electricity demand has grown significantly with an average rate of 7.1 per cent per annum. Consumption is expected to double again by 2020 and triple by 2030, when compared to 2013. In accordance with future projections of electricity demand, the Ministry of Energy, Mines, Water and Environment (MEMEE) announced that capacity should rise from 6,343.7 MW at the end of 2010 to 14,580 MW by 2020.[4] In 2014, the residential sector consumed 41 per cent of total energy consumption, the industrial sector consumed 24 per cent, the agriculture sector consumed 14 per cent and the tertiary and administrative sectors consumed 21 per cent combined (Figure 3). The national electrification rate is close to 100 per cent, with a rural electrification rate of 98.95 per cent at the end of 2014.[2]

FIGURE 3

Annual electricity consumption by sector in Morocco (%)



Source: ONEE[3]

Electricity generation is provided by the state-owned National Office for Electricity and Drinking Water (ONEE), who operate hydropower, thermal power plants and wind farms. In addition, there are three independent power producers (IPPs) and power producers from renewable energy (RE) sources. The three IPPs are: The JorfLasfar Energy Company (JLEC), Energie Electrique de Tahaddart (EET) and Compagnie Eolienne du Detroit (CED). The JLEC is the largest electricity generating facility in Morocco (with an expansion of 700 MW in 2013) and operates a 1,360 MW coal power plant. The EET operates a 380 MW gas-fuelled combined-cycle power plant and the CED operates a 50 MW wind park. All three IPPs operate on the basis of a concession and a power purchase agreement entered into with the ONEE. The total capacity of the plant is granted exclusively in favour of the ONEE. The construction and operation of the plants have been awarded on the basis of public and transparent calls for tenders, and are open to national and foreign investors. The electricity transmission grid consists of high voltage (HV) and very high-voltage (VHV) lines (60, 150, 225 and 400 kV) with a total length of 22,995 km. It covers the entire country and is connected to the Algerian and Spanish power grids via regional links. The grid is exclusively owned by the ONEE, which carries out the duties of transmission system operator.

The tariff structure is uniform regardless of the distributor, but is relatively complex because it differentiates between uses:

- Private lighting (lights, mosques, timers, consulates, non-governmental organizations, associations, parking);
- Patented lighting (commercial offices subject to a patent such as cabinets, cafes, restaurants, private schools);
- Domestic use (all premises used as dwellings);
- Driving force (a subscription with a driving force such as artisans, elevators, small textile companies, wells, mills);
- Subscriptions for special construction (for the purposes of work by contractors, parties, fairs, carnivals, etc.).

Each tariff is then divided into further subsections, with consumers paying according to their monthly consumption. In addition, there is a rural Noor tariff, which operates by a system-prepaid card with a price per kWh based on installed power (less than 13 kW) and a two time system for large consumers, including domestic. As the Government seeks to reduce subsidies and therefore increase prices, tariffs are relatively high by regional standards but remain below generation costs. Since 1 August 2014, both water and electricity rates increased and were based on new consumption levels. The rate increase was 2.9 per cent for low voltage, 6.1 per cent for medium voltage, and 4.7 per cent for high and very high voltage. Residential tariffs range from 0.9 Moroccan Dirham (US$0.11) per kWh to 1.49 Moroccan Dirham (US$0.18) per kWh. Professional tariffs range from 0.61 Moroccan Dirham (US$0.07) per kWh to 1.33 Moroccan Dirham (US$0.16) per kWh.[5]

Morocco is highly dependent on energy imports for its primary energy supply. It is the only Northern African country without large oil reserves, making Morocco very dependent on its neighbours. Over 91 per cent of energy supplied comes from abroad in the form of coal and oil world markets, such as gas from Algeria and imported electricity. This dependency, along with the vitality of the international energy prices, is the main issue that the Moroccan energy sector faces. As a result, the main objectives in the country's energy agenda revolve around providing sufficient and reliable energy to the economy and the population while ensuring the preservation of the environment.[14] This energy policy was set up in 2009 on five strategic axes:

- Security of supply with diversification of fuel types and sources;
- Availability and generalization of energy access to all segments of society at affordable prices;
- Mobilization of domestic energy sources, mainly RE and at the same time intensification of hydrocarbon exploration and oil shale valorization;
- Promotion of energy efficiency;
- Regional energy integration among the African and the Euro-Mediterranean markets.[10]

Small hydropower sector overview and potential

Morocco bases its definition of small hydropower (SHP) on the classification of the International Union of Producers and Distributors of Electrical Energy. The classification defines pico hydropower as any plant below 20 kW, micro hydropower as any plant between 20 and 500 kW, mini hydropower as any plant between 500 kW and 2 MW, and SHP as any plant between 2 MW and 10 MW.[17] Despite the classification, it should be noted that some government agencies classify SHP according to the specific context of the plant. For example, if the SHP plant is used within the context of agriculture, then the standard definition of 10 MW or less will be used to officially document the plant.[18] Additionally, it should also be noted that the Government has developed a new RE platform under Law No. 13-09, which promotes new power plant installations and even connection to the national grid. However, an administrative body is called to give authority over any plant with a capacity of 2 MW or greater.[19] Therefore, the pico, micro and mini classification is not always heavily considered in Morocco. For the purposes of this paper, the standard definition of 10 MW or less will be used to define SHP. The list of installed SHP plants in Morocco is provided in Table 1. However, three plants do not have an available installed capacity.

TABLE 1

Installed small hydropower plants up to 10 MW in Morocco

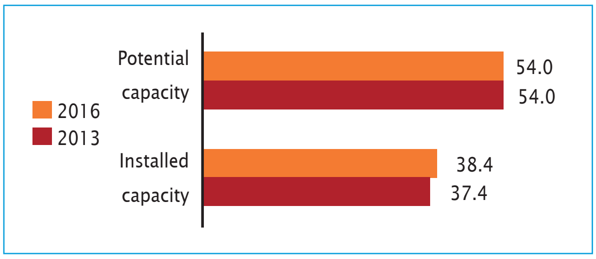
Plant name	Installed capacity (MW)	Generation in 2014 (GWh)
Al Kanser	8.3	19
Bouareg	2.3	3
MansourEddahbi	10	15.2
Daourat	8.5	1.1
Takerkoust	4.4	6.1
Imfaout	N/A	22
Taza	N/A	2.4
Sefrou	N/A	1.2

Source: ONEE[15]

The sum of the installed capacity in the table without the three plants is 33.5 MW. Therefore, the current installed capacity is estimated at 38.4 MW, with an additional potential of at least another 15.6 MW, indicating that approximately 70 per cent has so far been developed. The estimate was calculated using data from *World Small Hydropower Development Report* (*WSHPDR*) *2013* and the limited information on the Ministry of Energy. In comparison to data from *WSHPDR 2013*, installed capacity has increased marginally while the total estimated potential has remained the same (Figure 4).[6,7,8]

FIGURE 4

Small hydropower capacities 2013-2016 in Morocco (MW)



Sources: MEMEE,[4] *WSHPDR 2013*,[5] ONEE[15]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2013*.

Morocco has made the development of its hydropower potential one of the foundations for its economic and social progress agenda, and making significant investments in this sector. Current installed capacity of all hydropower in Morocco is 1,770 MW, with SHP accounting for approximately 2 per cent of the total.[4] The annual report from the ONEE states that the net hydropower generation, including the production from pumped-storage plants, reached 2,032.9 GWh in 2014 against 2,990.4 GWh in 2013.[15]

Morocco, in particular, was highlighted by the United Nations in September 2012 as having a particular potential for micro and mini hydropower plants.[9] A micro hydropower development programme was launched in 2010 with the ONEE identifying some 200 sites that could be developed. The first phase of this programme is the operation, and maintenance of existing plants and the development, financing, construction, operation and maintenance of two new plants at Oum Er Rbia.

Renewable energy policy

According to the National Energy Strategy, RE is to provide 10-12 per cent of primary energy supply and 42 per cent of total installed capacity by 2020. The Government has a target of 2 GW installed capacity each for solar, wind and hydropower by 2020. With a current installed capacity of 1.67 GW, the 2-GW target for hydropower is less ambitious than those for wind and solar energy. As of the end of 2015, wind power capacity stood at 797 MW and solar power at 161 MW. In order to meet the target of 2 GW by 2020, the ONEE is investing some 3.5 billion Moroccan Dirhams (US$390 million) in wind energy. By 2030, wind energy is expected to reach a capacity of 5,520 MW.[10]

Since the announcement of the RE programmes, appropriate legal, institutional and regulatory frameworks have been adopted to accompany the national strategy for developing the electricity sector and RE sources. Law No. 13-09, the RE law, aims to promote energy production from renewable sources and its marketing and exporting by public or private entities. It also allows energy developers to invest in RE projects and sell the electricity to a chosen client—even for export—on the basis of a negotiated contract. By opening up the medium, high and very high voltage levels for private power producers, this law brings about competition in electricity production, though some developers complain about slow authorisation procedures, particularly in terms of technical approval through the ONEE.[11] Law No. 16-08 permits the auto-generation of up to 50 MW of electricity though RE installations by industrial clients. Several new agencies have also been created, such as the National Agency for the Development of Renewable Energy and Energy Efficiency, the Moroccan Agency for Solar Energy, the Research Institute of Solar Energy and the New Energy Institute.

Barriers to small hydropower development

While there still remains a large amount of hydropower potential in Morocco, much of the current focus is on large scale hydropower production.[9] In order to promote the development of SHP plants, new studies are needed to ascertain the total potential for plants below 10 MW, as well as introduce new legislation and financial incentives for their development.

1.3.4 Sudan

Abdeen Mustafa Omer, Energy Research Institute

Key facts

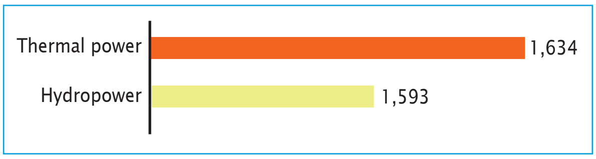
Population	36,108,853[1]
Area	1,861,484 km[2]
Climate	Sudan has a tropical sub-continental climate with a wide range of variations extending from a desert climate in the north to an equatorial climate in the south. The mean temperature ranges between 30°C and 40°C in summer and between 10°C and 25*C in winter.[2]
Topography	Sudan is a landlocked country comprising a gentle sloping plain, with the exception of Jebel Marra, the Red Sea Hills, Nuba Mountains and Imatong Hills. Its main features are the alluvial clay deposits in the central and eastern regions, the stabilised sand dunes in the western and northern regions and the red ironstone soils in the south. The highest point is Kirson Tonga in the south of the country reaching 2,799 m.[2]
Rain pattern	The average annual rainfall is 416 mm but ranges between 25 mm in the north and over 1,600 mm in the south. The rainy season lasts from July to October. However, it is shorter in the north.[2]
General dissipation of rivers and other water sources	Sudan is rich in water resources from the Nile system. Surface water resources are estimated at 84 billion m³ while the total quantity of groundwater is estimated to be 260 billion m³.[8]

Electricity sector overview

The total installed capacity in 2015 was 3,227 MW, with hydropower generation capacity (small and large) at 1,593 MW and the remainder coming from thermal power plants including diesel, gas, steam and combined power (Figure 1).[20] The total electricity generation in 2015 was 13,133 GWh, of which hydropower provided approximately 64 per cent, steam power plants provided 23 per cent, combined power plants provided 10 per cent, diesel power plants provided 2 per cent, and gas turbine power plants provided less than 1 per cent.

FIGURE 1

Installed electricity capacity in Sudan by source (MW)



Source: Ministry of Water Resources and Electricity[20]

The national electrification rate is 60 per cent and the rural electrification rate is 20 per cent.[12] Total electricity consumption in 2012 was 640 GWh, representing a per capita consumption of 53 kWh a year. It is estimated that total energy consumption will increase by 30 per cent by 2025, while electricity demand will increase by 70 per cent.

The Ministry of Energy and Mining (MEM) is in charge of the energy sector in general and the recently established Ministry of Water Resources and Electricity is now responsible for electricity generation. The National Electricity Corporation, which operates under the MEM, owns and operates hydropower plants, isolated diesel systems, and thermal and steam plants. The state-owned Sudanese Electricity Transmission Company Ltd and the Sudanese Electricity Distribution Company manage transmission and distribution respectively. The Electricity Regulatory Authority is the sector regulator.

The power sector has been characterized by a significant deterioration of its generation and network equipment, the dominant position of oil generation and the absence of necessary reserves to cover peak demand. Imperfection of both tariff and pricing policies for energy resources systems further compounds the issue in Sudan. However, recent changes in legislation now promote new projects to modernize the country's power industry and enable a greener energy future.[9] The country has a generation and transmission programme, which is expected to increase total capacity to 3,383 MW in 2016. In 2015, the Sudanese Parliament passed the National Electricity Bill to provide the establishment of a regulatory framework to govern the generation, transmission, supply, distribution, export and import of electricity and system operation.

The Government also decided to proceed with the 1,250 MW Merowe project on the River Nile, approximately 350 km north of Khartoum. The large hydropower dam came fully online in 2009. The project includes a 60 metre high, 4,800 metre long concrete-faced rockfill dam, with a powerhouse containing ten 125 MW units. The French Alstom, the Chinese Harbin Power and several Arab investors have contributed in funding the construction of the Merowe facility.

The Kajbar Dam is another large hydropower plant that has been proposed by the Government. The Chinese Sino Hydro has stated that it will finance 75 per cent of the US$200 million Kajbar dam construction, with the Sudanese Government providing the remaining 25 per cent. Environmental groups have expressed concern about the Kajbar project, citing potential damage to the Nile ecosystem and the culture of displaced Nubian residents of the area.[4]

The end consumer tariffs range from 0.16 Sudanese Pounds (US$0.042) per kWh for industrial consumers, to 0.34 Sudanese Pounds (US$0.089) per kWh for commercial consumers (Table 1).[16]

TABLE 1

Consumer electricity tariffs in Sudan by consumer type

Consumer category	Tariff (Sudanese pounds (US$) per kWh)
Industrial	0.16-0.18 (0.042-0.047)
Commercial	0.34 (0.089)
Governmental	0.70 (0.183)
Agricultural	0.16 (0.042)
Residential (> 200 kWh per month)	0.26 (0.068)
Residential (1-200 kWh per month)	0.15 (0.039)

Source: RCREEE[16]

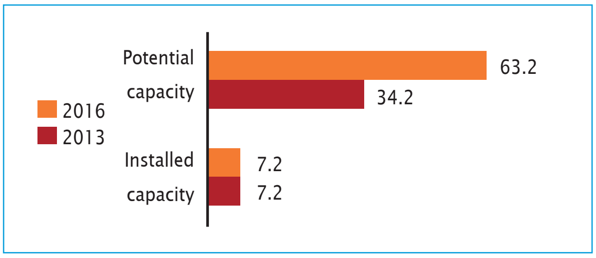
Small hydropower sector overview and potential

The Government of Sudan defines small hydropower (SHP) as any hydropower plant with a capacity between 500 kW and 5 MW. The Government also defines mini hydropower as any plant with a capacity of 50 kW to 500 kW, and micro hydropower as any plant of less than 50 kW capacity.[19] As of 2016, the total potential capacity of SHP is 63.2 MW. This total includes the El Girba 2 power plant which has three 2.4 MW units, totalling 7.2 MW.[4]

There have been no country-wide studies focused on estimating the potential of SHP in Sudan. However, the Government has established a renewable energy (RE) target which aims to install 56 MW of additional SHP by 2031.[20] Therefore, this report assumes that the potential is at least 63.2 MW. In comparison with *World Small Hydropower Development Report* (*WSHPDR*) *2013*, installed capacity has remained the same while potential has increased significantly (Figure 2).[17] This is due to an increase in publicly available data.

FIGURE 2

Small hydropower capacities 2013-2016 in Sudan (MW)



Sources: Abuaglla,[4] Omer,[13] *WSHPDR 2013*[17]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Although there has been no country-wide study, a number of prospective areas have been identified for SHP development using waterfalls with heads ranging from 1 to 100 metres.

TABLE 2

Operating hydropower plants in Sudan (MW)

Name	Year	Installed capacity (MW)
Sennar	1962	15
Roseires	1972	280
Girba 1	1964	10.6
Girba 2	1964	7.2
JabalAulia	2003	30.4
Merowe	2009	1,250

Source: Abuaglla[4]

In addition, the River Nile water could be used to run in-stream turbines, with water then pumped to riverside farms. There are more than 200 suitable sites for the use of in-stream turbines along the Blue Nile and the main River Nile. The total potential of mini hydropower plants is estimated at 67 GWh for the Southern Region, 3,785 MWh in the Jebel Marra and 4,895 MWh in the El Gezira and El Managil Canals.[6]

Renewable energy policy

Although Sudan has a large amount of potential RE resources, only a fraction of it has been developed so far. There is no regulatory or legal framework for RE specifically. There is no obligation to conclude long-term power purchase agreements with RE producers, no feed-in tariffs, no net-metering policy for small-scale projects and no priority access for renewable energy granted by law.

Barriers to small hydropower development

Key barriers to the development of SHP in Sudan include:

- Low level of public awareness of the economic/environmental benefits of SHP plants;
- Generally low levels of individual income;
- Poor pricing of hydropower plants, especially in the local market;
- Weak institutional capabilities of the various Energy Research Institutes;
- Problems with data collection. Information is needed for developing energy policies which would take into account all current and prospective developments in the energy sector and help design a sustainable strategy with various energy mix options.
- Absence of an effective project plan and delivery, as well as a lack of experts in the renewable energy sector. Projects tend to end up much more expensive than initially planned;[10]
- Limited regulation of technical specifications in particular for the power grid connection;
- Challenge of transporting RE generated electricity through the transmission system to the consumption centres of the country;
- There have been seven different ministries in charge of the power sector of Sudan since 1989, often with limited knowledge handover, creating a confusion and weak fulfilment of previous plans.

1.3.5 Tunisia

Nouri Chtorou, Soukaina Fersi, Emna Omri and Rim Jemli, University of Sfax

Key facts

Population	10,982,800[1]
Area	155,360 km[2]
Climate	The north of Tunisia benefits from a Mediterranean climate, the centre as well as the Gulf of Gabes have a semi-arid climate and the rest of the country has a desert arid climate.[2]
Topography	The country is divided into three distinct regions. The northern region is characterized by mountains, cork forests and grass lands. The central region is a semi-arid steppe plateau with olive groves. The southern region, which stretches from the Algerian border to the Mediterranean, contains date palm oases and saline lakes. The extreme south of Tunisia merges into the Sahara Desert. The highest point is called Jebel Chambi (1,544 metres), near Kasserine.[2]
Rain pattern	In the north of the country, rainfall is between 400 mm/year and 1,500 mm/year in the far north-west. The central region of Tunisia receives 200-400 mm per year, while in the southern regions of the country, the rains become rare and account for about 50-200 mm/year.[3]
General dissipation of rivers and other water sources	The most important river system in Tunisia, the Medjerda, rises in Algeria and drains into the Gulf of Tunis. Its course has a length of 460 kilometres It is the only river that flows perennially; other watercourses fill only seasonally. In the central Tunisian steppes, occasional waterways flow southward out of the Dorsale after heavy rains, but they evaporate in salt flats without reaching the sea.[3]

Electricity sector overview

The energy sector in Tunisia is characterized by a steady rise of energy demand and decrease of national resources. In 1994, the net import of energy was 0.25 Mtoe. It started increasing from 1999 and in 2012 it was 2.99 Mtoe.[4] Electricity generation in 2013 was 17,672 GWh. The installed capacity increased from 4,117 MW in 2012 to 4,334 MW in 2013, due to the implementation of two wind farms in Metline and Kchabta (Bizerte) during the second half of 2013 and two gas turbines in Bir M'Chergua (Zaghouan). The energy sector primarily uses natural gas, which accounts for more than 90 per cent of electricity production, so the national generation capacity is composed essentially of steam turbines, gas turbines and combined cycle. The share of wind and hydropower in electricity production is very insignificant compared to the potential of those two resources in Tunisia (Figure 1).

FIGURE 1

Installed electricity capacity in Tunisia by source (MW)

Source: Tunisian Company of Electricity and Gas[6]
Note: Data from 2013, conflicting data suggests 66 MW of installed hydropower capacity.[16]

The continuous volatility of fossil fuel prices and the increase of an energy deficit have caused many negative economic repercussions, including massive outflows of foreign currency and an increase in public spending, as fossil fuels are subsidized by the Government.

Another feature of the energy sector is the vast amount of conventional energy subsidies. In 2013, 14 per cent of the state budget or 5 per cent of the country's Gross Domestic Product was allocated to energy subsidies.[5] There are many factors which affect the amount of subsidies, including deficit of resources, gas prices, the price of imported energy and currency exchange rates.

The dependency on natural gas makes Tunisia vulnerable to technological, market and geopolitical risks. For example, the volume of gas transit from Algeria to Italy has fallen since 2010, which resulted in the decrease of the tax package attached to the Trans-Tunisian gas pipeline and therefore the worsening of the energy deficit. The electricity distribution grid extended to 156,594 km in 2013 (53,885 km of medium-voltage lines and 102,709 km of low-voltage lines) compared to 152,709 km in 2012, an increase of 2.5 per cent. Concerning the national electrification rate, in 2013, the total was 99.5 per cent. In rural areas, it was 98.90 per cent.[7]

The main actor in the electricity sector is the state-owned Tunisian Company of Electricity and Gas (STEG), which is responsible for generation and distribution. The

Tunisian electricity market is partially liberalized. Due to the enacting of Decree 1996-1125 (1996) and Law 96-27 (1996), the private generation of electricity is possible through concessions given by state authorities.[7]

Energy prices at all levels are set by the Ministry of Industry in collaboration with relevant government agencies such as the General Direction for Energy, the Tunisian Enterprise of Petroleum Activities (ETAP), the Tunisian Company of Refining Industries (STIR), the Ministry of Commerce and the Ministry of Finance. The energy prices are set at the end of each fiscal year. Prices are influenced by numerous factors, including the international price of crude oil and gas, the financial situation of STEG, the ETAP and the STIR, as well as the amount government subsidies.[7]

After the STEG's price policies have been approved by the Government, the Ministry sets consumer prices of gas and electricity. Until 2004, the STEG's prices reflected approximate production costs and grants (e.g. rural electrification, or tariffs for certain categories of rural consumers) and were fed mainly by cross-subsidies between tariffs.[7]

The electricity tariffs are arranged by time slots for high voltage (HV) and medium voltage (MV) and pumping water for agricultural irrigation. There are four time shifts: day, peak, evening and night. Depending on time shifts and monthly consumption, prices vary from US$0.047/kWh to US$0.144/kWh.[7]

Small hydropower sector overview and potential

For the purposes of this report, the definition of small hydropower (SHP) in Tunisia will be considered up to 10 MW. Installed capacity of SHP in Tunisia is 16.98 MW, while the potential is estimated to be 55.98 MW indicating that less than 63 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has decreased by approximately 41 per cent. Estimated potential was not available in the 2013 report (Figure 2).

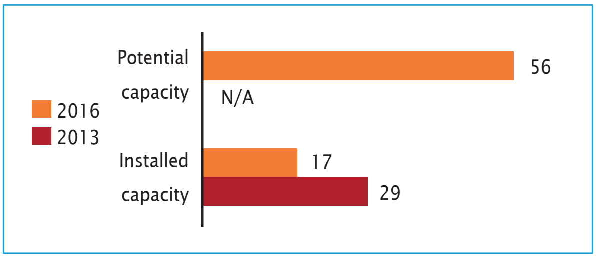
Although there is no internationally agreed definition of SHP, this report will use the upper limit of 10 MW of installed capacity, which is usually used in Tunisia.

Tunisia has a great theoretical hydropower potential, estimated at 1,000 GWh/year in the mid-1990s, but the technically feasible potential is only approximately 250 GWh/year, with 66 MW of hydroelectric power generation capacity installed in the country. The oldest hydroelectric power plant is located in Nebeur (North of Tunisia, Government of Kef). Built in 1956, it is a dam with a river reservoir and has a capacity of 13.2 MW.

There are seven hydropower plants in Tunisia. Many of them were built during the period of French colonization

FIGURE 2

Small hydropower capacities 2013-2016 in Tunisia (MW)



Sources: *WSHPDR 2013*,[15] STEG,[10] Saidi and Fnaiech[11]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

and most of them are located in the north-western region. The total installed capacity of these plants is 66 MW with electricity generation between 50-160 GWh.[10,16]

The seven hydropower plants in Tunisia are:

- Sidi-Salem (36 MW);
- Nebeur (13.2 MW);
- El Aroussia (4.8 MW);
- Sejnane (0.6 MW);
- Kasseb (0.66 MW);
- Fernana (8.5+1.2 MW);
- Bouhertma (1.2+0.62 MW).[10]

The two hydropower plants of Sidi Salem and Nebeur have capacities of 36 MW and 13.2 MW respectively. Therefore, there are only five SHP plants in Tunisia, which are El Aroussia, Sejnane, Kasseb, Fernana and Bouhertma. It should be noted that the hydropower plant of Sejnane, with a capacity of 0.6 MW, is not operating currently. So the overall operational installed capacity is 16.98 MW.

The renewable energy (RE) strategy in Tunisia is focused on solar and wind energy, which receive the support of the Government, and little interest is given to hydropower, either from the Government or private investors. This explains the stagnation of the installed capacity of hydropower compared to other sources of RE in Tunisia.

According to some reports and studies, there is the possibility to construct nine other SHP plants with capacities ranging from 250 kW to 3 MW. The sites and capacities of these plants are as follows: Barbara (3 MW), Bouhertma (1.2 MW), Sejnane (1 MW), Sidi Saad (1.75 kW), Siliana (850 kW), Bejaoua (750 kW), KhanguetZezia (650 kW), Nebhana (500 kW) and Medjez el Bab (250 kW). The total capacity of the programme is expected to be 10 MW.[11]

Renewable energy policy

In order to lower dependency on natural gas and reduce the conventional energy subsidies, Tunisia has made efforts to promote RE and energy efficiency. The National Agency for Energy Management is an organization established in 1985, with the goal of implementing national policy in the field of RE and energy efficiency. Another organization, STEG-ER, was established in 2010 with the objective of promoting the national RE policy. It engages in the development of public-private partnership in RE and energy efficiency. In addition, it contributes to the leadership and the development of Tunisian Solar Plan (TSP). STEG-ER activities are mainly feasibility studies, construction, operation and maintenance of RE and cogeneration power plants. It provides its expertise, assistance and know-how for projects in RE and energy efficiency. As a key player in the realization of the TSP, STEG-ER aims to develop installed power from RE to 1,000 MW in 2016 and 4,700 MW by 2030.[12]

The main goals of the first national energy three-year programme of Tunisia (2005-2007) were to increase capacity of RE and improve energy efficiency.[13] Several programmes for energy conservation for the period 2008-2011 were established with the main objective of increasing the share of RE in primary energy consumption to 4 per cent in 2011. In order to strengthen national RE policy beyond the four-year plan, Tunisia has established the TSP, which incorporates all renewable technology and energy effectiveness according to the view of the Mediterranean Solar Plan. The main result of the TSP should be a reduction of fossil fuel consumption.

On 15 April 2015, the Assembly of People's Representatives adopted the draft law for the production of electricity from RE. The main objective of this law is to encourage investments in the field of RE, to increase the share of RE in electricity generation (30 per cent of generation by 2030) and to contribute to the diminution of the energy deficit. This law stipulates the liberalisation of production and that the export of electricity produced by the private sector or public services should derive from RE. It allows public enterprises and local authorities to produce electricity and sell it to STEG. It is based on four main areas: the establishment of a National Plan of electricity produced from RE sources, incentives for private initiative, expanding the self-power generation system for consumption of local authorities and the organization of the export of electricity. The distribution of electricity and transport remain exclusively the prerogative of STEG.

Barriers to small hydropower development

There are barriers common to all RE projects, namely the lack of clear-cut policies, a lack of budgetary allocations and the absence of long-term financing to ensure price affordability. In addition to these, SHP implementation is hindered by:

- Limited access to appropriate technologies in the mini, micro and pico hydropower categories, which pose special technical challenges.
- Limited infrastructure for manufacturing, installation and operation. An example is the availability of capacity to manufacture high-density polyvinyl pipes that can serve as good penstocks for the micro hydropower schemes. Few countries have these products and as such, exploitation of otherwise simple sites has been hampered by this deficiency.
- Limited specialization to undertake feasibility studies, detailed studies that would include specifications for design and the cost of the schemes to make a meaningful impact on utilization of SHP sites.[14]

1.4 Southern Africa

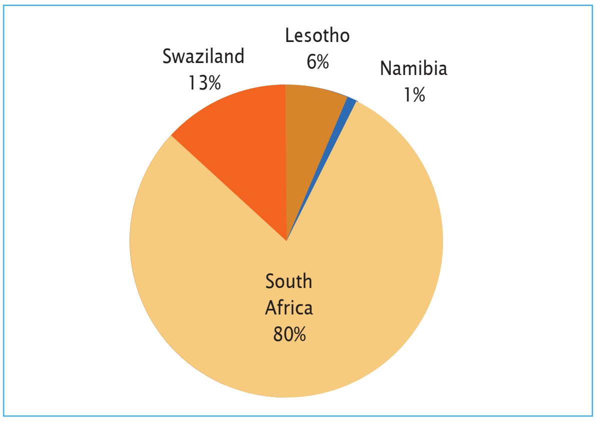
Wim Jonker Klunne, Energy and Environment Partnership Programme

Introduction to the region

The region of Southern Africa comprises five countries: Namibia, Botswana, South Africa, Lesotho and Swaziland. As of May 2016, the total installed capacity of small hydropower (SHP) in the region was 62.5 MW, with most of it located in South Africa. Most of the countries in the region have a low electrification rate (29-53 per cent). Only in South Africa does the electrification rate reach 85.4 per cent.

FIGURE 1

Share of regional installed capacity of SHP by country



Source: *WSHPDR 2016*[11]

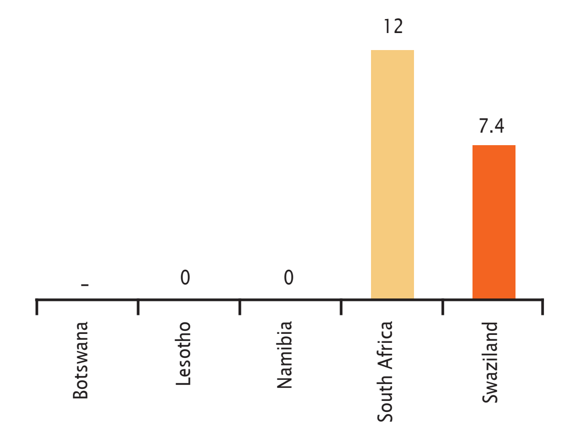
The region has various climatic conditions, from tropical to temperate, semi-arid and desert, some of which are more suitable for hydropower than others.

The countries in the region are interconnected through the Southern African Power Pool. Although several initiatives in the region are promoting renewable energy (RE), including SHP, the region is substantially dependent on coal-generated electricity from South Africa. Lesotho, Namibia and Swaziland produce all or most of their electricity from large-scale hydropower, while South Africa is still mostly coal-dependent.

At the regional level, the Southern African Development Committee (SADC) is trying to coordinate international support for energy development in the region, including RE. In collaboration with the United Nations Industrial Development Organization, the SADC is currently setting up the Southern African Centre for Renewable Energy and Energy Efficiency in Namibia.

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for Southern Africa



Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[11]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.

TABLE 1

Overview of countries in Southern Africa (+/- % change from 2013)

Country	Total population (million)	Rural population (%)	National electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Botswana	2.22	43	53	892	871	0	0
Lesotho	2.11 (+9%)	73 (0pp)	29 (+13pp)	76 (0%)	457 (+129%)	76 (0%)	457 (+129%)
Namibia	2.40 (+11%)	54 (-8pp)	47 (+13pp)	487 (+24%)	1,498 (+5%)	332 (+33%)	1,485 (+27%)
South Africa	54.0 (+11%)	36 (-2pp)	85 (+10pp)	49,578 (+12%)	236,760 (+8%)	2,276 (+225%)	4,083 (+277%)
Swaziland	1.27 (-8%)	79 (0pp)	42 (+15pp)	69.6 (+16%)*	231 (-)	60.1 (0%)	159 (+28%)
Total	**59.6 (+10%)**	—	—	**51,102.6 (+14%)**	**239,817 (+9%)**	**2,744.1 (+153%)**	**6,184 (+140%)**

Sources: Various[1,2,6,7,8,12,13,14,15]
Notes:
a. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative change can be due to closures or rehabilitation of sites, and/or due to access to more accurate data for previous reporting. Change in regional population compared with 2013 does not include Botswana. For Swaziland, data provided is for grid-connected installed capacity.
b. An asterisk (*) indicates data compared with the country report in *WSHPDR 2013* and not the regional summary.

Small hydropower definition

Countries of the region do not have official definitions for SHP, therefore, in this report the definition of SHP of plants with a capacity of up to 10 MW will be used for all five countries.

Regional SHP overview and renewable energy policy

The most significant energy resource in the region is solar energy, with many RE policies identifying it as the most important area for development. Wind power can also be developed in certain countries. Four countries in the region use SHP (Table 2).

TABLE 2

Installed and potential SHP capacity in Southern Africa (+/– % change from 2013)

Country	Potential (MW)	Installed capacity (MW)
Botswana	1	0
Lesotho	20 (0%)	3.82 (0%)
Namibia	108 (–0.5%)	0.5 (0%)
South Africa	247 (0%)	50 (+32%)
Swaziland	16.21 (+103%)	8.21 (+926%)
Total	**392.21 (+2%)**	**62.53 (+45%)**

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[11]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. Data is for <10 MW.

Botswana has a very limited SHP potential, estimated at 1 MW and is currently not using SHP. Solar power is the most important source of RE in the country, with an average daily solar radiation of 6.1 KWh/m^2. Nonetheless, the photovoltaic systems installed in the country have the capacity of 1 MW, accounting for only 0.8 per cent of the country's total installed capacity.

Lesotho has two operational SHP plants of 0.57 MW and 0.18 MW, both owned and operated by the national utility Lesotho Electricity Company. Although there is an untapped potential of approximately 16 MW and some plans exist for construction of additional SHP capacity, the circumstances do not seem to facilitate swift development of these projects. Nonetheless, the Lesotho Highlands water project does offer opportunities for more hydropower development. Several studies have also been conducted on possible pumped-storage plants. Besides hydropower, Lesotho has identified wind and solar power as potential RE sources. Solar power has been implemented in several schemes with the support of the World Bank, the UNDP and the Global Environment Faculty.

The current installed SHP capacity of Namibia is 0.5 MW and the potential is estimated at 108 MW. Namibia has a hydropower resource development Master Plan based on a study performed on the country's major rivers. However, all the identified sites have a capacity above 10 MW, thus none of them fall into the category of SHP according to the generally accepted definition. Nonetheless, there are hundreds of small farm dams around the country, where SHP could be developed. The Namibia Power Corporation, the leading national energy company, set the target of sourcing at least 10 per cent of national energy from renewable sources other than hydropower. It also launched tenders for independent power producers (IPPs) to develop 30 MW of solar power, as part of a national program to commission a total of 94 MW through solar and wind technologies.

South Africa has 50 MW of installed SHP capacity and a proved potential of 247 MW (up to 10 MW). SHP played an important role in the country's electrification, but was not developed for decades until recently. The Integrated Resource Plan of South Africa outlines the expected electricity mix in the country through 2030, including the envisaged role of hydropower. The government has implemented this plan through the Renewable Energy Independent Power Producers Procurement Programme (REIPPPP), which targets to add 17,800 MW of RE (solar and wind) to the country's installed capacity as well as 75 MW from SHP. This programme has already resulted in the installation of three SHP systems (19.1 MW) contracted by the government for feeding into the national grid. Parallel to this, a number of privately owned systems have been developed, purely for private consumption. Traditionally, the country's energy policy has focused on large-scale, grid-connected RE projects. However, with the national energy regulator, NERSA, preparing guidelines and policies targeting small-scale plants, future activities in the area of small power plants development, including SHP, will be facilitated. The future development of SHP in South Africa will be based both on IPP-developed plants feeding into the national electricity system and small-scale plants for private use not feeding into the grid. Currently, no support is available for stand-alone systems for rural electrification purposes, although the government is currently reviewing its rural electrification strategy.

The first electric lighting system in Swaziland was installed with a 42 kW SHP turbine. Since then, the country has had several public and private hydropower plants installed, as well as some industrial installations. The total installed SHP capacity of Swaziland is at 8.21 MW, including one decommissioned plant of 0.5 MW. At the national level a comprehensive resource assessment has been carried out showing that there is at least 8 MW available for further SHP development, with some sites currently being under consideration. Since 2007, Swaziland has had a strategic framework and an action plan for development of renewable energy in the country. The government seeks to maximize the use of RE, encourage education and training on RE, promote greater awareness of RE and develop accurate data on available RE resources. However, the development in this area has been relatively slow.

Barriers to small hydropower development

The current electricity situation in the region, which combines limited availability of electricity with increasing prices, does create an enabling environment for renewable energy technologies.

Limiting factors for SHP include vague legislative frameworks, unfamiliarity with the technology, a lack of suitable business models and in some cases conflicts over access to water and land.

1.4.1 Botswana

Marcis Galauska, International Center on Small Hydro Power

Key facts

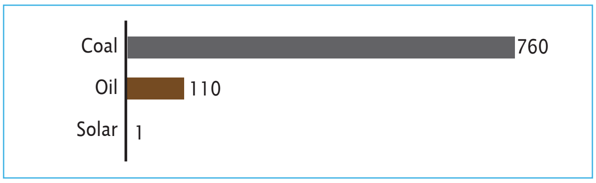
Population	2,219,937[1]
Area	581,730 km[2]
Climate	The climate is arid and semi-arid. Although it is hot and dry for much of the year, there is a rainy season from October to March. Rainfall tends to be erratic and highly regional. Temperatures can reach 40°C in summer and ranges between 5°C and 23°C in winter.[2]
Topography	The country is a predominantly flat, with a mean altitude of 1,000 m above sea level. A vast plateau divides the country into two parts: the hilly region in the east and the Okavango Swamps and the Kalahari Desert in the west. The highest point is the Monalanong Hill, at 1,494 m above sea level.[3]
Rain pattern	The rainy season is in summer (October to March). January and February are generally regarded as the wettest months. The rain pattern is highly irregular with frequent droughts. The mean annual precipitation is 416 mm, ranging from a maximum of over 650 mm in the north to a minimum of 250 mm in the south-west.[2]
General dissipation of rivers and other water sources	There are five major drainage basins, The Limpopo basin drains 14 per cent of the country; the Orange basin, 12 per cent; the Zambezi basin, 2 per cent; the Okavango basin, 9 per cent; and the South Interior basin, 63 per cent. The Chobe River, the Limpopo River and the Okavango River are the only sources of year-round surface water.[2,3]

Electricity sector overview

Electricity generation in 2013 was 871 GWh. 760 GWh were generated from coal, 110 GWh from oil and 1 GWh from solar power, while 2,872 GWh were imported. This makes the overall domestic supply 3,743 GWh (Figure 1).[4] In 2014, the installed capacity was 892 MW, although the available capacity was only 680 MW.[14] The country has two coal-fired plants: Morupule A (132 MW) and Morupule B (600 MW). It also has two emergency diesel plants: Orapa (90 MW) and Matshelagabedi (70 MW).[7] According to the World Bank, the electrification rate of Botswana in 2014 was 53.2 per cent.[5] Currently, the electricity grid is not available in north-western Botswana.

FIGURE 1

Electricity generation in Botswana by source (GWh)



Source: IEA[4]

The Country's Department of Energy Affairs of the Ministry of Minerals, Energy and Water Resources is the regulatory authority in charge of the energy sector. Botswana Power Corporation (BPC) is a state-owned company responsible for electricity generation, transmission and distribution, and reports to the Ministry.[6] In 2014, as a result of the Corporation's transformation from an electricity retailer to an electricity generator with a higher asset base as a result of increased generation and transmission infrastructure, it was decided by the Ministry and BPC that BPC would be subject to a management contract for three years. The tender was given to Electricity Supply Board International, which is expected to enhance BPC's performance, introduce organizational reforms and prepare it for competition in the electricity market in line with the Government's decision to open it up to independent power producers.[13]

In 2014, Botswana imported 1,783 GWh of electricity, against the total consumption of 3,703 GWh. The major supplier was Eskom of South Africa at 1,569 GWh. Other suppliers were Electricidade de Moçambique, Namibia Power Corporation, Zambia Electricity Supply Corporation and the Southern African Power Pool Day Ahead Market.[7]

For the general development of the electricity sector and in order to decrease import dependence, BPC plans to increase the installed capacity to 998 MW by 2017, including an increase in the capacity of the thermal power plant Morupule B.[15] The objectives of the Morupule B Generation and Transmission Project are to support Botswana in:

- Developing reliable and affordable supply of electricity for energy security
- Promoting alternative energy resources for low-carbon growth
- Building its institutional capacity in the energy sector

The Government also plans to construct a transmission system and to install the following:

- Morupule Phokoje 400 kV transmission line (102 km) and associated equipment
- Morupule-Isang 400 kV transmission line (215 km)

The project is partially funded by the World Bank.[8]

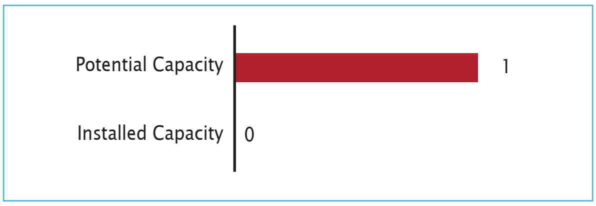
Botswana Power Corporation customers are categorized into six classes based on the use and size of supply consumed. The fixed tariff is approximately US$1.9 for residential users and US$5.7 for other types of consumers. Rates vary from approximately US$0.05 to US$0.1/kWh depending on the user and the amount of consumption.[12]

Small hydropower sector overview and potential

Currently, there are no hydropower plants in operation. Due to the severe water shortages Botswana faced in 2015, it is highly unlikely that any hydropower projects will be developed in the near future. However, there is a potential for development of 1 MW, located in the north of the country (Figure 2).[9]

FIGURE 2

SHP capacity in Botswana (MW)



Source: Klunne, W, J.[9]

Renewable energy policy

The most important source for renewable energy (RE) in the country is solar power, as the average solar radiation is high at 6.1 kWh/m^2 per day. Since 1990, a number of photovoltaic pilot projects have been started in Botswana. Wind energy potential in Botswana is moderate. According to the European Centre for Medium-Range Weather Forecasts (ECMWF) average wind speed at the height of 100 m is 5-7 m/s.[10]

General electrification is the main objective of the Government. In 2012, it introduced feed-in tariffs (FITs) for RE sources (up to 5 MW). As the main emphasis of the tariffs is creating an incentive for solar power projects, a total of 118 prospective companies have applied to be considered as partners in the generation of power through renewable sources. As of October 2015, the Government of Botswana was also in the process of negotiating a 900 MW solar energy project with the Government of Israel.[11]

Barriers to small hydropower development

Despite the RE friendly policies of the country, with particular regard to solar energy incentives, large and small-scale hydropower project development faces one insurmountable barrier, namely a severe shortage of water resources. With an abundance of solar energy and wind resources, it is unlikely that hydropower development will be pursued in the near future.

1.4.2 Lesotho

Wim Jonker Klunne, Energy and Environment Partnership Programme (EEP)

Key facts

Population	2,109,197[1]
Area	30,360 km^2
Climate	A temperate climate 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 down to -20°C in winter.[3]
Topography	Lesotho is completely surrounded by the Republic of South Africa. It is also the only country in the world entirely situated above 1,000 m in altitude. Approximately one-quarter of the land area is lowlands located in the west, varying in altitude between 1,500-1,600 m above sea level. The remaining three-quarters are highlands rising up to 3,482 m above sea level at Thabana-Ntlenyana in the Maluti Range.[1]
Rain pattern	Rainfall is seasonally distributed with up to 85 per cent of the total received from October-April. Average annual precipitation is 788 mm varying from 300 mm in the western lowlands to 1,600 mm in the north-eastern highlands.[3]
General dissipation of rivers and other water sources	Two of the largest rivers in Southern Africa, the Orange (Senqu) River and the Tugela River, and tributaries of the Caledon River, have their source in the northern region of the country. 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 Caladon covering the rest.[1,3]

Electricity sector overview

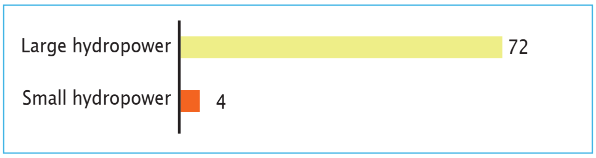
Lesotho does not have any proven domestic reserves of oil, coal or natural gas and heavily depends on biomass fuels in the forms of wood, shrubs, animal dung and crop residues to meet the needs of the majority of the rural population. The only other fuels consumed in significant quantities are mineral coal and paraffin. At the same time, the country has a good potential for the development of renewable energy (RE), in particular wind, solar and hydropower.[14]

The electricity sector is relatively small, contributing just 3 per cent of the total energy consumed. The total installed capacity is 76 MW (Figure 1), all of which comes from hydropower, mainly from the 72 MW Muela hydropower plant, which was commissioned in 1998 as part of the Lesotho Highlands Water Project. The project is being developed by the Governments of Lesotho and South Africa and aims to provide electricity as well as a source of income for Lesotho and to provide water to Gauteng province of South Africa.[17]

As of 2013, 29 per cent of households in Lesotho had access to electricity, primarily concentrated in the urban and growth centres where infrastructure services are relatively well-developed in terms of transmission and distribution.[18] In 2012, only 10 per cent of the rural population had access to electricity.[2] The Government aims to achieve a 40 per cent national electrification rate by 2020.[18]

FIGURE 1

Installed electricity capacity in Lesotho by source (MW)



Source: Reegle[4]

In 2013 Lesotho generated 456.9 GWh of electricity, down from 485.4 GWh in 2012.[20] The national demand for electricity continues to exceed local generation, which has stayed more or less unchanged for more than two decades. In 2013, more than 50 per cent of electricity consumption was met by electricity imports.[14] Lesotho imports electricity from Eskom in South Africa and Electricidade de Moçambique within the Southern African Power Pool.

The electricity sector in Lesotho is regulated by the Lesotho Electricity Authority (LEA), which is in charge of licensing, electricity pricing, setting and monitoring quality of supply and service standards as well as complaints handling and resolution. LEA regulates all aspects of the industry: generation, transmission, distribution, supply, import and export of electricity.[16]

The electricity sector is dominated by two state-owned entities, the Lesotho Electricity Company (LEC) and

The Lesotho Highlands Water Development Authority (LHWDA). LEC is a parastatal entity established under the Electricity Act 7 of 1969, and responsible for electricity generation, distribution, transmission and supply. LHWDA is the agency responsible for electricity generation from the Muela hydropower station. Activities of these two bodies are regulated by the 1993 Policy on the LHWDA/ LEC interface.[4] Independent power producers (IPPs) are allowed to produce electricity for sale to the national utility as well as to distribute generated electricity to the communities. However, their participation has been constrained by the lack of a defined framework.[17]

TABLE 1

Consumer electricity tariffs in Lesotho 2015/2016

Customer Category	Approved energy charges (LSL (US$) per kWh)*
Industrial high voltage	0.2155 (0.0248)
Industrial low voltage	0.2326 (0.0267)
Commercial high voltage	0.2155 (0.0248)
Commercial low voltage	0.2326 (0.0267)
General purpose	1.3753 (0.1582)
Domestic	1.2249 (0.1409)
Street lighting	0.7260 (0.0835)

* Includes customer and electrification levies
Source: LEWA[13]

Consumer tariffs range from LSL 0.2155 (US$0.0248) per kWh for high voltage commercial and industrial consumption to LSL 1.3753 (US$0.1582) per kWh for domestic customers (Table 1).[13]

Small hydropower sector overview and potential

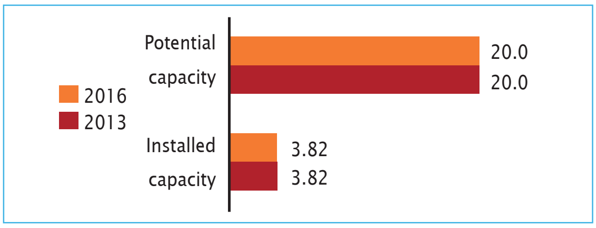
There is no official definition of small hydropower (SHP) in Lesotho. However, this report assumes a definition of plants with an installed capacity of less than 10 MW. Current installed capacity is 3.82 MW with a total potential of 20 MW. This indicates that approximately 19 per cent of the country's SHP potential has been developed. However, it should be noted that not all of the installed capacity is currently operational. In comparison with the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, neither installed nor potential capacity has changed (Figure 2).[16]

As of 2015, the country had five SHP plants, namely Mantsonyane (2 MW), Tlokoeng (670 kW), Katse (570 kW), Tsoelike (400 kW, and Semonkong (180 kW). Out of these five, only Katse and Semonkong are currently operational (Table 2).

The Mantsonyane hydropower plant, located on the Mantsony'ane River in central Lesotho, was financed by a grant from Norway and commissioned in 1989. The power station is connected to the LEC grid through the Mantsony'ane substation on the 33 kV Mazenod-Taba Tseka line. It 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. The design head is 35.5 m. As a result of flooding in 2006, the plant has been out of operation.[9] A rehabilitation process has been commenced with the support of the African Development Bank (AfDB), as part of the Lesotho Electricity Supply Project.[10]

FIGURE 2

SHP capacities 2013-2016 in Lesotho (MW)



Sources: Various[5,7,8,9,10,16]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

TABLE 2

SHP plants in Lesotho (MW)

Plant name	Installed capacity (MW)	Year commissioned	Status
Mantsonyane	2.00	1989	Non-operational
Tlokoeng	0.67	1990	Non-operational
Katse	0.57	2000	Operational
Tsoelike	0.40	1990	Non-operational
Semonkong	0.18	1988	Operational
Total	**3.82**		

Source: Various[7,8,9,10]

The 570 kW Tlokoeng plant is located in the eastern part of the country and is serving the town of Mokhotlong. Built in 1990 with French development aid, the plant has two Francis turbines of 460 kW and 210 kW and two diesel generators as backup. Over its operational life the plant 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.[7] The station had a number of technical problems, including bearing failures, exciter problems and flooding in 1996. The plant was decommissioned in 2002 when Mokhotlong was connected to the Letseng diamond mine through a 33 kV transmission line. Since then there have been plans to use the plant for peak loading and/or operation as an IPP, but no concrete steps have been taken to this effect. Furthermore, the difficult access situation and limited availability of spare parts for the original French equipment have inhibited development of the site.

The Katse plant, with a capacity of 570 kW, is located on the Katse Dam, which is the second largest dam in Southern Africa. It was commissioned in 2000 and has one horizontal Francis turbine and an 800 kVA synchronous generator. The plant is not connected to the LEC grid and serves as the main power source to the Katse Dam electricity requirements. However, it is planned to link the plant to the national grid.[8]

The Tsoelike hydropower plant, consisting of two Francis hydro turbine generation units with a combined capacity of 400 kW, was commissioned in 1990 to serve the town of Qacha's Nek in the south of Lesotho as part of the French development assistance. The two turbines are supplemented by a 200-kVA diesel generator set located on a ledge next to the power station as well as a 320 kVA set in Qacha's Nek. The station was decommissioned when Qacha's Nek was connected to the South African Eskom grid in 1997.

The Semonkong hydropower plant with an installed capacity of 180 kW, supplemented by a 120 kW diesel generator was commissioned in 1980 as part of the Norwegian development aid project to support the development of hydropower in Lesotho. Currently, due to considerable wear on the Sorumsand Verksted turbine, the equipment is able to produce only 125 kW of energy. The diesel generator has been upgraded twice since its installation and is currently a 180 kW Cummins unit. 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. In the powerhouse, ample space is allotted for a second turbine. However, installation is only feasible if a larger dam is constructed for increased water supply.[11]

All locally generated electricity in Lesotho is hydropower based, with the 72 MW 'Muela plant providing the majority, currently only augmented by the two operational mini hydropower plants. The Lesotho Highlands Water project does offer opportunities for more hydropower development and several studies have been conducted on possible pumped-storage plants as well.

The large-scale hydropower potential of Lesotho is estimated at approximately 450 MW. A number of studies have been carried out to investigate the country's SHP potential. By 1990, 22 sites for both mini and micro-hydro power with a total capacity of 20 MW had been identified.[5] In the range of 100 kW to 1,000 kW, the French company Sogreah (today part of Artelia) studied nine potential sites and completed feasibility studies on three preferred sites (Tlokoeng, Motete and Qacha's Neck). In the micro range of hydropower, a report by the NERCA estimates that there are from 20 to 40 feasible sites in the country with an average capacity of 25 kW.[6]

Taele et al. summarize the current situation with SHP in Lesotho as follows: "The environment is presently conducive for development of SHP systems in the country. First, the country has adequate hydropower resources. The settlement pattern of the country in the rural areas favours decentralized systems of which SHP is one of the viable means of improving access to electricity. The present legislation allows for independent power producers/distributors to operate in the country therefore there is no threat to International Partners willing to operate SHP plants. One of the duties of the regulator is to relax the standards slightly for rural electrification projects. This will lower the costs of providing electricity in the rural areas. Very soon, the National Rural Electrification Fund will be up and running. This will supplement the capital requirements for new projects."[5]

However, the reality on the ground has proven to be difficult for international partners to find viable business models for the development of SHP in Lesotho. Tarini Hydro Power Lesotho Ltd., a subsidiary of Tarini in India, has been trying for a few of years to launch two hydropower projects (the 80 MW Oxbow plant and the 15 MW Quithing project), but still has not been able to have construction started. It is hoped that the renewed interest in RE in the South African Development Community will help Lesotho in developing its SHP potential.

Large-scale hydropower, particularly pumped storage, has been part of Phase 2 of the Lesotho Highlands Water Project. This includes the 1,200 MW Kobong Pumped-Storage project, which is currently in the feasibility phase. Furthermore, in 2009, the AfDB approved a loan for a program aimed at the electricity supply of Lesotho, including a study of the 1,000 MW Monontsa pumped-storage project.[12]

Renewable energy policy

Hydropower is the main source of electricity for Lesotho, whereas wind and solar power have been identified as potential RE sources as the country enjoys favourable conditions for their development. In particular wind power potential has been estimated at 6,000 MW with three sites being investigated for setting up a wind farm.[19] Solar power has been implemented in several schemes such as the World Bank project and the UNDP/GEF project.

The Lesotho Energy Policy 2015-2025 noted that renewable sources of energy and energy efficiency are expected to play a significant role in the country's future energy plans and explicitly stated the Government aim of improving access to RE services and technologies. Strategies and programs include facilitating the establishment of rural energy service companies (RESCOs) and developing a RE program to support fuel substitution. Additionally, the policy notes the need to establish power purchase agreements for IPPs of RE sources as well as creating an enabling environment for investors with the potential for establishing RE feed-in tariffs (FITs).[14]

Barriers to small hydropower development

In order to boost SHP electricity production, viable business models for the development of SHP in Lesotho need to be found. Institutional barriers to SHP development include a lack of effective infrastructure, fragmented institutional responsibilities and a lack of integrated planning. From the economic and commercial point of view, SHP development in Lesotho can be hindered by the rather small size of the potential market and the limited ability to pay on the part of the rural population. Moreover, the country has limited skilled manpower required for SHP construction, operation and maintenance. The general awareness of SHP as well as other RE technologies is rather low. Finally, some sites are difficult to access and there is limited availability of spare parts in the local market.[19]

1.4.3 Namibia

Zivayi Chiguvare, Namibia Energy Institute

Key facts

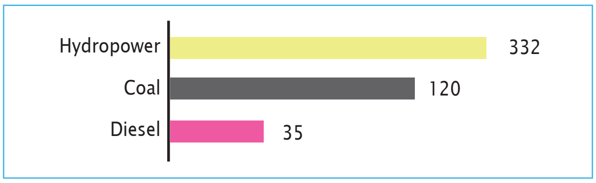
Population	2,402,858[1]
Area	823,290 km^2
Climate	Namibia has a hot and dry desert climate with sparse and erratic rainfall. Namibia has the driest climate in Africa. Its mean annual temperatures are above 22°C in the north, between 20°C and 22°C in the interior, and below 16°C along the southern coast. In Windhoek, temperatures range between 6°C and 20°C in July and between 17°C and 29°C in January.[2]
Topography	The terrain is mostly high plateau with the Namib Desert along the coast and the Kalahari Desert in east. The average altitude is 1,080 m above sea level and the highest point is Mount Konigstein, at 2,606 m.[2]
Rain pattern	Rainfall is particularly scarce and unpredictable, aggravated by an extremely high rate of evaporation. Much of Namibia is a land of perennial drought. The annual rainfall, concentrated in the summer period (November to March), generally averages 700 mm in the far north, 25-150 mm in the south and 350 mm on the central plateau.[2].
General dissipation of rivers and other water sources	The only perennial rivers are the Kunene and Okavango on the northern border and the Orange River on the southern border.[2]

Electricity sector overview

In 2014, the total installed electricity generation capacity in Namibia was 487 MW, some 68 per cent of which was provided by the Ruacana hydropower plant, with the Van Eck coal powered plant providing approximately 24.5 per cent and two diesel power plants providing the remainder (Figure 1).

FIGURE 1

Installed electricity capacity in Namibia by source (MW)



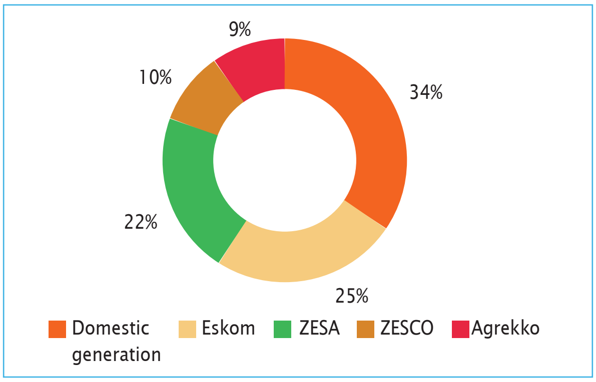
Source: NamPower[3]

The total generation in 2014 was approximately 1,498 GWh.[3] Even with the 2012 expansion of the Ruacana plant to its current capacity, the total generation still falls short of the country's 550 MW demand. To satisfy the demand, in 2014, Namibia imported approximately 66 per cent of its electricity from neighbouring countries. 1,091 GWh was provided by Eskom in South Africa, 962 GWh by the Zimbabwe Electricity Supply Authority, 420 GWh by the Zambia Electricity Supply Corporation and 413 GWh by Agrekko in Mozambique (Figure 2).[3]

For 2015, it was expected that Namibia Power Corporation (NamPower) would spend approximately US$220 million on imported electricity.[4] Namibia is also part of the Southern African Power Pool (SAPP), contributing roughly 1 per cent to the total peak demand of SAPP.[5,3]

FIGURE 2

Domestic and imported electricity in Namibia (%)



Source: NamPower[3]

Some 54 per cent of the Namibian population lives in rural areas.[1] With the dispersion of the population over large parts of the country, grid extension is often unviable. The national electrification rate is 47 per cent.[1] All of the country's 17 municipalities and 19 towns are connected to the grid. While urban access to electricity is at 94 per cent, rural access is much lower, at 17 per cent.[1]

The Government supports two energy initiatives to help speed up the electrification process. A Regional Electricity Distribution Master Plan (REDMP) will connect a large number of rural settlements to the main distribution grid over the next 20 years, though it is not economically feasible or technically possible to electrify all off-grid settlements. Approximately 1,543 rural communities will be electrified over the next 20 years by the REDMP, as outlined by the Ministry of Mines and Energy. It is expected that 4,315 communities will remain without access to the national grid. For those settlements, there is the Off-grid Energisation Master Plan. However, this plan does not include a hydropower option, instead focusing more on wind and solar sources.[14,15] NamPower increased its rural electrification budget to 25 million Namibian dollars (US$2.9 million) from 20 million Namibian dollars (US$2.3 million) in the 2014/2015 financial year.[6]

The Namibian power sector is currently dominated by Nampower, a vertically integrated electricity utility with a monopoly over generation and transmission. NamPower is wholly owned by the Government of Namibia, but was established as a private company by South Africa to operate the Ruacana hydropower project in 1964. Thus, NamPower continues to maintain a strong degree of independence from the State, despite being wholly government-owned.[7]

In the areas not served by NamPower, electricity is also distributed by local authorities and regional electricity distribution companies. In 2002 the Government launched a process of developing a single buyer model to support small power producers. The model is based on five regional electricity distribution companies, which are created from local distribution networks and buy power from small power producers (up to 2.5 MW). After the completion of the sector restructuring, it is expected that NamPower will act as a power generator, whereas individual power producers (IPPs) and interconnected generators will retain a monopoly over electricity transmission.[7]

The Electricity Control Board (ECB) is the body responsible for the electricity sector regulation, including electricity generation, transmission, distribution, supply, import and export through setting tariffs and advising the Minister of Mines and Energy on licensing. The ECB is also in charge of promoting private sector investment in the electricity sector.[7]

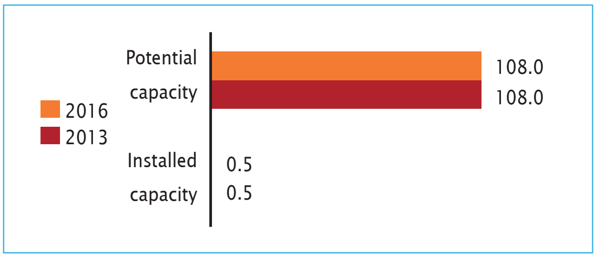
In 2014/15 the distribution tariff for small power users was NAD 1.89 (US$0.217) per kWh and NAD 1.09 (US$0.125) per kWh for large power users.[8]

Small hydropower sector overview and potential

Currently no official small hydropower (SHP) definition exists in Namibia. However, this report assumes a definition of up to 10 MW. The country has a SHP installed capacity of 0.5 MW, with a potential of 108 MW suggesting that just less than 1 per cent of the country's potential has been developed.[9] In comparison to the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, there has been no change in the installed capacity or the estimated potential (Figure 3).[10]

FIGURE 3

SHP capacities 2013-2016 in Namibia (MW)



Sources: IJHD,[9] *WSHPDR 2013*[10]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

In 2008, the country drafted a Hydropower Master Plan based on a study of the cost and production of all potential sites on the country's perennial rivers: the lower Kunene, Kavango and lower Orange Rivers. All the identified sites have a capacity above 10 MW, and thus do not fall into the category of SHP.[11] Nonetheless, according to the 2008 National Investment Brief, there are hundreds of small farm dams suitable for SHP development.[10] Additionally, as of 2011, a further three SHP plants with a total capacity of 26 MW were planned for construction.[13] Several SHP projects are also being considered on the lower Orange River to be operated by IPPs and could be developed in the next three to four years. The estimated cost is between US$5 million and US$35 million for a total capacity of 70 MW. The lower Orange River is, however, already highly disturbed by major dams, irrigation projects etc. and the Orange River mouth is a protected Ramsar site.

Namibia has a total estimated hydropower potential of 2,250 MW, with SHP potential contributing approximately 5 per cent. There are a number of large hydropower plans including the 500 MW Baynes hydropower project, which is currently the subject of a feasibility study and environmental impact assessment. This project is a joint venture that would supply both Namibia and Angola. The Popa Falls hydropower project has a potential capacity of 20 MW. Unfortunately, the project was shelved in 2003 after a pre-feasibility study was completed, due to the low estimated power output.[3,12]

Renewable energy policy

NamPower has created a renewable energy (RE) section as well as launched a RE policy, which includes the target of a 10 per cent share of renewable sources (other than hydropower) in the national energy mix. Originally this target was set for 2011 but it was not achieved. Nonetheless, NamPower has begun tenders for 30 MW of solar photovoltaic power to be provided by an IPP, as part of a broader program to commission 94 MW of power through a mix of solar and wind technologies.[3] There are currently no financial incentives, such as feed-in tariffs (FITs), for RE producers.[5]

Barriers to small hydropower development

The Namibian energy sector faces future challenges in increasing the current generating capacity to decrease its dependency on imports, for which RE in general and SHP in particular could play an important role. However, there is a range of barriers to SHP development in the country. Firstly, the country has scarce water resources and depends on its neighbours for water supply. Secondly, there is a lack of clear governmental policy, legislative frameworks and fiscal incentives. Lastly, indigenous people are concerned about the hydropower industry and its impact on their way of life causing a conflict over internal land use.

1.4.4 South Africa

Wim Jonker Klunne, Energy & Environment Partnership Programme (EEP)

Key facts

Population	54,001,953[1]
Area	1,219,602 km[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 m) keeps the average summer temperatures below 30°C. In winter, night temperatures can drop to the freezing point.[2]
Topography	It has a vast interior plateau rimmed by rugged hills and a narrow coastal plain. Its height above sea level varies from about 1,500 m in the dolerite-capped Roggeveld scarp in the south-west to 3,482 m in the KwaZulu-Natal Drakensberg.[2]
Rain pattern	The 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 receives more than 600 mm of rainfall. The Western Cape gets most of its rainfall in winter, while the rest of the country generally sees wetter summers.[2]
General dissipation of rivers and other water sources	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

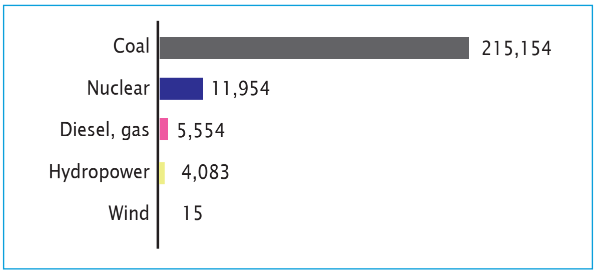
In South Africa, coal accounts for about 90 per cent of electricity generation. The Koeberg nuclear power station provides about 5 per cent of generation, gas and diesel provide about 2 per cent, hydropower (including pump-storage) provides 2 per cent and the remaining is provided by wind power (Figure 1). In 2013, South Africa generated 236,760 GWh of electricity.[26]

With the commissioning of the contracted renewable energy (RE) technologies through the Renewable Energy Independent Power Producers Procurement Programme (REIPPPP), the energy landscape in the country is changing rapidly. In particular, wind and solar PV are contributing increasingly to the energy mix of the country. By mid 2015, 1,860 MW of RE capacity supplied electricity to the national grid.[6] As of early 2016, RE IPPs had 2,021 MW connected to the grid.[25]

Generation is dominated by Eskom, the national wholly state-owned utility, which also owns and operates the national electricity grid. In 2015, Eskom provided 214,742 GWh (93 per cent) of the total 230,122 GWh distributed in the country.[5,7] The company also sells electricity to the countries of the Southern African Development Community (SADC) and in total accounts for approximately 45 per cent of the electricity used in Africa .[24]

FIGURE 1

Electricity generation by source in South Africa (TWh)



Source: Statistics South Africa[8]
Note: Data from 2013. An asterisk (*) indicates data includes pump-storage hydropower plants.

In 2011, the Department of Energy published the Integrated Resource Plan (IRP) outlining the development of new generation capacities from 2010-2030. The Government's target is to provide 17,800 GW of new power generation capacity from wind and solar power by 2030. The main source of hydropower, according to IRP, will be the import of 2,609 MW from Mozambique and Zambia, while local, small-scale hydropower and landfill gas based electricity were allocated a share of 125 MW.[3]

By the end of 2015, the REIPPP had successfully allocated

5,052 MW of RE generation capacity to 79 preferred bidders, including three small hydropower (SHP) projects totaling 19.1 MW.[4]

Table 1 provides an overview of the power purchasing agreement (PPA) prices achieved in the REIPPP. The price of ZAR 1.12 per MWh (approximately US$6.92/MWh) as per the fourth bidding window can be used as a reference for the cost of SHP in South Africa. Unfortunately, connecting to the national grid outside the REIPPP process is very difficult and only possible at prices far below the REIPPP PPA prices.[7]

TABLE 1

Prices realized in ZAR/kWh (US$/kWh) at different bidding windows of the REIPPPP

Technology	BW 1	BW 2	BW 3	BW 3.5	BW 4
Onshore wind	1.36 (0.084)	1.07 (0.066)	0.78 (0.048)	—	0.68 (0.042)
Solar PV	3.29 (0.023)	1.96 (0.121)	1.05 (0.065)	—	0.82 (0.05)
Solar CSP	3.20 (0.2)	3.00 (0.185)	1.74 (0.107)	1.62 (0.1)	—
Landfill gas	—	—	1.00 (0.062)	—	—
Biomass	—	—	1.49 (0.092)	—	—
Small hydro	—	1.23 (0.076)	—	—	1.12 (0.069)

Source: DoE[7]
Note: Fully indexed to April 2014.

Small hydropower sector overview and potential

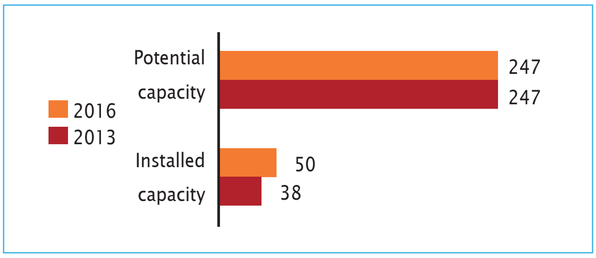
The REIPPPP process has initiated substantial activity in hydropower development. During the first three bidding windows, the maximum size of SHP plants was set at 10 MW. However, in the Request for Qualifications and Proposal for the fourth bidding window in June 2014, a new capacity limit of 40 MW for SHP was introduced. Nonetheless, no official definition of SHP exists in the country. Therefore, this report will classify all hydropower plants up to 10 MW as SHP plants.

The installed capacity of SHP in South Africa is 50 MW, while the potential is estimated to be 247 MW. This indicates that only 20 per cent has been developed. However, the longer-term feasible potential could be upwards of 1,100 MW. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, the installed capacity has increased by almost 32 per cent, while the potential has remained unchanged (Figure 2).

Small-scale hydropower used to play an important role in the electrification of both urban and rural areas of South Africa, including Cape Town and Pretoria. Smaller towns used to have their own local electricity distribution networks with isolated grids powered by SHP plants. However, many of those systems were decommissioned as a result of the expansion of the national electricity grid and the cheap, coal-generated power supplied through this grid. For example, the 1.35 MW Sabie Gorge hydropower plant was commissioned in 1928 to serve the town of Sabie, but closed in 1964 when the area was connected to the national Eskom grid.[21] After almost 30 years of neglect, SHP development was re-launched with the construction of the first new SHP plant in the Sol Plaatje Municipality in the Free State province.

FIGURE 2

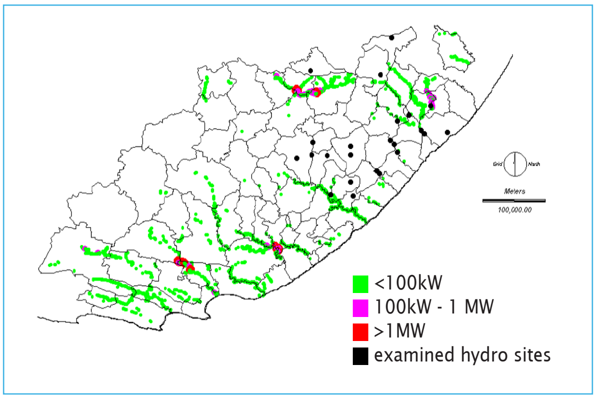
SHP capacities 2013-2016 in South Africa (MW)



Sources: B Barta,[9] *WSHPDR 2013*[20]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

FIGURE 3

SHP potential in the Eastern Cape



Source: Szewczuk et al.[22]

The South African Renewable Energy Database, developed by the Government, studied the availability of RE resources in the country, including hydropower.[19] Subsequently, a three-year project, entitled Renewable Energy Sources for Rural Electrification in South Africa, was undertaken to investigate the resources available in the Eastern Cape region and to identify commercially viable opportunities for rural electrification in the Eastern Cape Province using wind, hydro and biomass power. The outcomes of the two studies with respect to the potential of SHP in South Africa and the Eastern Cape are shown in Maps 1 and 2 respectively.

In the 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, the installed capacities of hydropower in South Africa and the potential for new developments were investigated.[23] It was concluded that more than two times the installed capacity of the present installed hydropower capacity below 10 MW can be developed in the rural areas of the Eastern Cape, Free State, KwaZulu Natal and Mpumalanga. A more recent estimate includes the potential of water transfer systems and gravity fed water systems with a total potential of 247 MW.[9]

In 2015, Eskom operated four large hydropower stations: Gariep (360 MW), Vanderkloof (240 MW), Colley Wobbles (42 MW) and Second Falls (11 MW) . It also operated two small stations: First Falls (6 MW) and Ncora (1.6 MW).[25] The small systems in the country can be divided into the following groups:

- Grid connected systems commissioned prior to the REIPPPP process;
- Systems installed under the REIPPPP process;
- Grid connected systems that fall outside the REIPPPP process;
- Stand-alone systems that do not feed into the national grid.

In the micro range, a substantial number of plants is in operation in the KwaZulu Natal and Eastern Cape region, mainly serving individual farmers.

Another application of hydropower in the country is the installation of in-flow hydropower turbines in water transfer systems. The City of Cape Town operates hydropower turbines at four of its water treatment plants: Blackheath (700 kW), Faure (1.475 MW), Steenbras (340 kW) and Wemmershoek (260 kW). The municipality of Ethekwini and Rand Water utility are developing six and four sites respectively. The City of Johannesburg has released a tender for the installation of 3 MW of hydropower capacity in its bulk water reticulation system. Furthermore, a 15-kW system was installed at the Pierre van Ryneveld Reservoir in Pretoria as part of a research project by the University of Pretoria. Bloemwater, the water distribution company of the city of Bloemfontein, has also commissioned a 96 kW system at the inlet of a water reservoir that is now providing power to the company's headquarters.[10]

The future of grid-tied systems is closely linked to the Government's policy on RE development. The 2030 target set for SHP by the IRP and the REIPPP is significantly less than the estimated potential and might therefore limit SHP development in the country.[11] In the second round of REIPPP, two hydro developers, Kakamas Hydro Electric Power and NuPlanet, were granted the preferred bidder status for the construction of the Neusberg plant (12.57 MW) and the Stortemelk plant (4.47 MW). However, for the Neusberg site, only 10 MW will be developed in accordance with the REIPPP requirements.[12,13] In the fourth round, the 4.7 MW Kruisvallei system was selected for implementation. Aside from operational systems, 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.[9]

SHP development in South Africa will be focused both on the development of 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). Additionally, isolated SHP systems can be used for electrification of rural areas. The private use of small-scale systems is expected to grow based on the foreseen rise in electricity prices and low reliability of the grid.

All in all, it is expected that SHP can play a small but important role in the future energy mix of the country.

Renewable energy policy

South Africa has a full suite of policies in place to support the energy sector, ranging from a White Paper on Energy Policy to a specific White Paper on Renewable Energy Policy. For the implementation of RE technologies, the REIPPPP is the vehicle. The REIPPPP was launched by the Department of Energy in 2011, switching from the feed-in tariff system that had been created in 2009.

Until very recently, the country's policy focus has been on large-scale, grid-connected RE. With the National Energy Regulator of South Africa preparing guidelines and policies for small-scale embedded generation, future activities related to SHP development, as well as other small-scale RE projects, will be facilitated.

Barriers to small hydropower development

The main barriers to the uptake of SHP in South Africa are the low cost of electricity, the cumbersome process of the REIPPP, the low appreciation of SHP technology due to perceived low potential and (in some cases) the reluctance of the Department of Water Affairs and Sanitation to provide the required permissions.

1.4.5 Swaziland

Wim Jonker Klunne, Energy and Environment Partnership Programme

Key facts

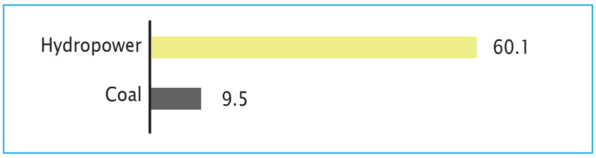
Population	1,269,112[1]
Area	17,364 km^2 [1]
Climate	Swaziland's climate is temperate in the west but may reach 40°C in the eastern Lowveld region during the summer months (October to March). In the capital city, Mbabane, temperatures average 20°C in January and 12°C in July.[2]
Topography	The Kingdom of Swaziland is a landlocked country in Southern Africa bordering South Africa in the north, south and west and Mozambique in the east. Swaziland is no more than 200 km north to south and 130 km east to west. The western half is mountainous at 1,050-1,200 m above sea level, descending to a Lowveld region to the east at 300 m above sea level. The eastern border is characterized by the escarpment of the Lebombo Mountains. The highest point is Emlembe at 1,862 m.[2]
Rain pattern	Rainfall occurs mainly in the summer months (October to March). Average annual rainfall may reach 1,550 mm in the western Highveld but decreases from west to east, with the Lowveld averaging between 400-550 mm. The country's average rainfall is 788 mm/year.[3]
General dissipation of rivers and other water sources	Major perennial rivers begin in South Africa and flow through Swaziland to the Indian Ocean: The Lomati, Komati, Umbuluzi and Usutu. The Usutu has the largest catchment in the country, with three main tributaries, the Usushwana, Ngwempisi, and Mkhondvo.[3]

Electricity sector overview

As of 2014, the total grid connected installed capacity was 69.6 MW from four hydropower plants, constituting 86 per cent of the total and one coal-powered plant providing the remainder (Figure 1).[16] In addition, there are several private self-generating plants owned by the industrial sector.

FIGURE 1

Installed electricity capacity in Swaziland by source (MW)



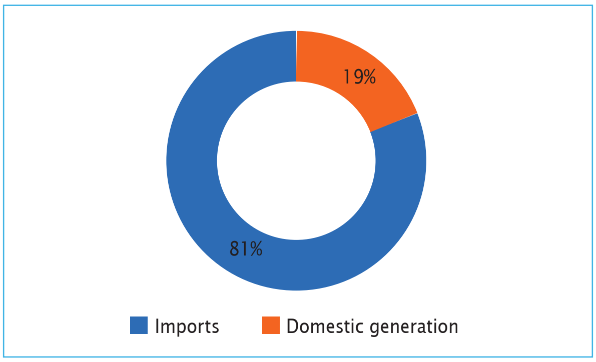
Source: SEC[16]

In 2015, the total generation of the grid was 231 GWh. However, in order to meet the demand, an additional 978 GWh was imported from South Africa through the Southern Africa Power Pool (Figure 2).[16] Swaziland is a member of the Southern African Customs Union and its currency, the Swazi Lilangeni, is pegged to the South African Rand. From an economic as well as an electrical perspective, Swaziland is strongly linked to South Africa.

The industrial and residential sectors lead consumption, consuming 34 and 33 per cent of the total respectively (Figure 3).[16] The overall electrification rate is estimated at 42 per cent, with 100 per cent of urban areas and only 25 per cent of rural areas electrified.[1] Biomass, especially wood fuel, constitutes approximately 90 per cent of the total energy consumed and is still predominant 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 saw mill industries.

FIGURE 2

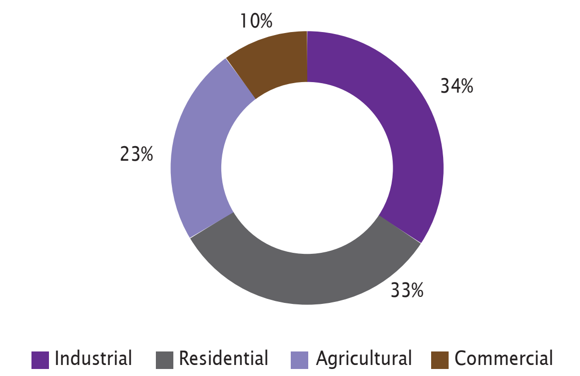
Imported and domestic generation in Swaziland in 2015 (%)



Source: SEC[16]

FIGURE 3

Electricity consumption in Swaziland by sector (%)



Source: SEC[16]

The Swaziland Electricity Company (SEC), which was established by the Swaziland Electricity Company Act of 2007, operates a monopoly on the import, distribution and supply of electricity via the national power grid and owns a majority of the country's power stations. The electricity sector is open to Independent Power Producers. However, as of December 2014 only Ubombo Sugar mill was selling power to EC under a Power Purchase Agreement.[14] Self-generation also plays an important role in the country.

In 2007, the Government undertook a reform in the electricity supply industry, which included changing SEC from a board to a company, establishing the Swaziland Energy Regulatory Authority (SERA) and preserving the state company as a more disciplined corporate entity.[1] The SERA is responsible for licensing, pricing and monitoring the performance of licensed operators.

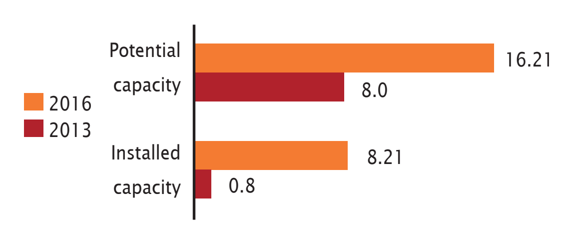
As of 1 April 2016, consumer tariffs ranged from SZL 0.6602 (US$0.105) per kWh to SZL 1.7768 (US$0.113) per kWh (Table 1).[17]

Small hydropower sector overview and potential

There is no official definition for small hydropower (SHP) in Swaziland. However, this report assumes a definition of plants with a capacity less than 10 MW. Installed capacity is currently 8.205 MW including the decommissioned but still technically operational 0.5 MW plants at Mbabane.[10] Potential capacity is estimated to be at least an additional 8 MW, indicating that more than 50 per cent has been developed so far.[5] In comparison to data from the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, both the installed and potential capacities have increased (Figure 4).[19]

FIGURE 4

SHP capacities 2013-2016 in Swaziland (MW)



Sources: Jonker-Klunne,[11] Knight Piésold Consulting,[5] *WSHPDR 2013*[19]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The first electric light in Swaziland was installed at Mlilwane with a 52.5 kVA hydropower turbine operated by James Weighton Reilly to separate tin from iron at the Mlilwane Tin Mine with an electrical extension bringing light to the farm house. Afterwards, several public and private hydro plants have been installed in the country, as well as hydraulic ram pumps to provide water for steam locomotives at the Ngwenya mine.

Currently only six hydropower stations are operational in the country, three of which are less than 10 MW

TABLE 1

Consumer tariffs in Swaziland by type for 2016/2017

Tariff type	Facility charge (SZL (US$) per month)	Energy charge (SZL (US$) per kWh)	Demand charge (SZL (US$) per kVA)	Access charge (SZL (US$) per kVA)
Life Line	—	1.1652 (0.076)	—	—
Domestic	—	1.2550 (0.082)	—	—
General purpose	182.5371(11.97)	1.7402 (0.114)	—	—
Small commercial – prepayment	182.5371 (11.97)	1.7402 (0.114)	—	—
Small commercial – credit meter	365.0742 (23.94)	1.7402 (0.114)	—	—
Small holder irrigation	1,617.4446 (106.05)	0.6602 (0.043)	110.8638 (7.27)	43.6504 (2.86)
Large commercial and industrial	1,902.8662 (124.77)	0.7768 (0.051)	130.4246 (8.55)	51.3135 (3.36)
Large irrigation	1,902.8662 (124.77)	0.7768 (0.051)	130.4246 (8.55)	51.3135 (3.36)

Source: SEC[17]

TABLE 2

Current hydropower plants in Swaziland

Station	Total capacity (MW)	Number of turbines	Turbine capacity (kW)	Year of construction	Owner
Ezulwini	20	2	10,000	1985	SEC
Maguga	19.5	2	9,600	2006	SEC
Edwaleni	15	4 + 1	2,500 + 5,000	1969	SEC
Maguduza	5.6	1	5,600	1969	SEC
Ubumbu Sugar	1.305	2	728	1986	Ubumbu Sugar
Swaziland Plantations	0.8	2	400	1952	Swaziland Plantations
Mbabane	0.5	2	250	1954	SEC [decommissioned]

Source: Jonker-Klunne[11]

(Table 2). The SEC operates the grid connected Ezulwini (20 MW), Maguga (19.5 MW) Edwaleni (15 MW), and the Maguduza (5.6 MW) installations. The Mbabane station of 500 kW was decommissioned by SEC in December 2010 as it was no longer able to operate the plant profitably.[6] Two private SHP plants are also in operation: the 800 kW system of Swaziland Plantations and the 1.305 MW station of Ubumbo Sugar in Big Bend.[7,8]

Both the Edwaleni and Maguduza plants feed from the Greater and the Little Usutu Rivers. In the mid to late 1980s, the SEC 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 stations' capacity to provide peak power but also caused severe wear on the turbines.[2] Currently the stations are free of siltation problems.

The Edwaleni station comprises three sets of diesel generation facilities (2 units of 4.5 MW and 1 unit of 0.5 MW). However, these are seldom utilized by the SEC because of the high costs involved.

The hydropower plant of Swaziland Plantations was initially commissioned in 1952, but was later built to provide power to the town of Piggs Peak. The water is taken from the Mkomazana River, with two 400 kW Francis turbines each connected to a three phase 415 kVA alternator. The alternators feed into an 800 kVA transformer, which is synchronized to the SEC system and feeds a 16 km, 11 kV line direct to the sawmill. During summer, when there is an abundance of water, the plant can provide approximately 90 per cent of the company's power needs.[7] Current operations are highly dependent on water availability with winter, dry season production accounting for approximately a quarter of summer production. The 1.305 MW hydropower plant on the Great Usuthu River was commissioned in 1986 and consists of two 728 kW Ossberger turbines. The station provides power to the sugar processing facilities in Big Bend.[8]

Several studies have been undertaken to estimate the country's total hydropower potential. In 1970, Engineering and Power Development Consultants, in a study sponsored by the United Nations Development Program, identified 21 potential sites for hydropower development, with an estimated potential of 3,000 GWh.[21] The 1980-1982 Energy Master Plan estimated the country's feasible hydropower potential at 550-700 GWh.[21]

The latest full study on hydropower potential in Swaziland was carried out by Knight Piesold Consulting in 2001. The study showed that there are 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 (Map 1).[5] As part of its objective to expand the hydropower sector, the Ministry of Natural Resources and Energy (MNRE), based on the work of Knight Piesold Consulting, has built a database of potential sites. This initially identified 35 sites ranging from 32 kW to 1.5 MW. The number of sites was further reduced to 26 in accordance with their potential for electricity generation. Four sites were identified as viable and are being promoted by MNRE, including the Lusushwana River (300 kW), the Mpuluzi River (155 kW), the Usutu River (490 kW) and the Mbuluzi River (120 kW minimum).[14]

Based on the existing information, the Environmental Centre for Swaziland estimates the gross theoretical potential at 440 MW and the technically exploitable potential at 110 MW.[14]

Feasibility studies of the Ngwempisi cascading scheme are currently being carried out. The expected total installed capacity is at 120 MW over three different sites, and at least one owner of an old non-operational 50 kW hydropower plant is considering rehabilitation.[9]

In addition, T-Colle Investments of Mbabane is looking to build a SZL 5 million (US$575,000) hydropower plant on a canal in the central Manzini region that would generate 360 kW of electricity. The firm will charge SEC SZL 0.70 (US$0.081) per kWh during the first three years of production.[10]

Renewable energy policy

In 2007, the Ministry of Natural Resources and Energy developed a strategic framework and action plan to:

- Establish a centre for demonstration and education on renewable energy (RE) and sustainable energy;
- Encourage and enhance, where applicable, topics on RE and energy in general in educational and training curricula;
- Maximize the use of RE technologies;
- Promote greater understanding and awareness of RE resources and the associated technologies;
- Develop and maintain accurate RE resource data and make it available to all;
- Develop woodlots in areas experiencing an acute fuel wood shortage.[18]

More recently, at the Global Energy Ministerial Dialogue of the SE4ALL forum in New York in May 2015, the Acting Principal Secretary of Natural Resources and Energy, Mrs Winnie T. Stewart, announced that commitment of the private sector to developing research and power generation from biomass and hydropower by 2018. The implementation modality of this is, however, unclear.[15]

Barriers to small hydropower development

The hydropower resources of Swaziland have been well documented. With the 2007 reforms in the electricity sector, Swaziland has created the legal framework for the introduction of independent power producers. However, until now, limited private sector investment has come forward. The renewed interest in hydropower as an energy source, as indicated through the recent studies on the Ngwempisi cascading system and the Lower Maguduza plant do indicate that new developments may be implemented soon.

The increasing electricity prices and reduced reliability of the national grid have also resulted in increased interest in rehabilitation of old defunct hydropower plants. Although no good overview exists of possible sites for refurbishment, it can be expected that a number of sites will be economically feasible to rehabilitate.

1.5 Western Africa

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Introduction to the region

Western Africa comprises 16 countries, of which 15 are members of the Economic Community of West African States (ECOWAS), as well as Mauritania and one territory. It is bordered by the Sahara to the north and the Atlantic Ocean to the west and south. This report focuses on 12 countries, namely Benin, Burkina Faso, Cote d'Ivoire, Gambia, Ghana, Guinea, Liberia, Mali, Nigeria, Senegal, Sierra Leone and Togo. All countries listed are members of ECOWAS. An overview of the countries in Western Africa is presented in Table 1.

The climate in Western Africa can be grouped into six different zones, from north to south: desert, semi-arid desert, semi-arid tropical, pure tropical, transitional tropical and transitional equatorial. The precipitation reaches from almost zero in the north of Mali and Niger to more than 3,000 mm in some coastal areas in Liberia. Generally, the seasonality (difference between dry and wet seasons) is very high in the region of Western Africa.

There are significantly high mountains and appropriate topographic conditions for small-scale hydropower potentials, especially in Guinea, Sierra Leone, Liberia and Nigeria, as well as in Côte d'Ivoire, Benin, south-west Burkina Faso, Ghana, southern Mali, and Togo. Mount Bintumani (also known as Loma Mansa) is the highest peak of 1,945 m in continental Western Africa, located in Sierra Leone.

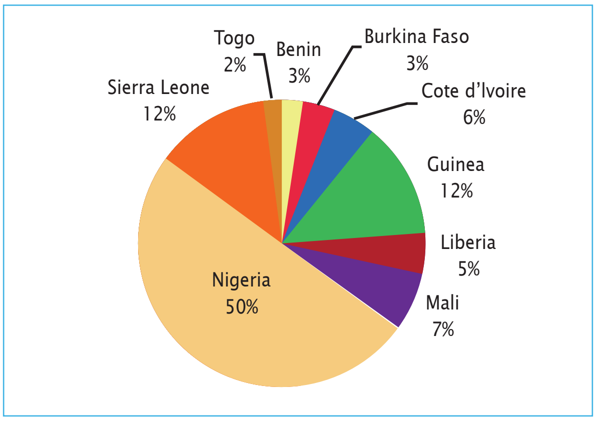
Several rivers with regional importance originate from the Guinean highlands, including the Senegal, Gambia, and Niger Rivers. Other important basins include the Volta basin and the Benue basin (which discharges into the Niger River). All Western African rivers discharge into the Atlantic Ocean, with the exception of the Yobe River, which flows towards Lake Chad. A unique topographical feature is the Inner Delta of the Niger River, which forms one of the largest wetlands of the world during the flood season.

In large parts of Western Africa, runoff is only a small fraction of rainfall, as most of the rainfall is lost via evapotranspiration. The regional distribution of runoff correlates with the rainfall distribution. Regions with below 800 mm annual rainfall produce very little runoff. In contrast, runoff is quite considerable in regions with high rainfall.

In most parts of West Africa, the discharge regime shows a strong seasonality with high flows from August-October and low flows from December-May. This seasonality in discharge is driven by the rainfall regime (rainy season and dry season). In some coastal regions, there is a second discharge peak in June.

FIGURE 1

Share of regional installed capacity of SHP by country

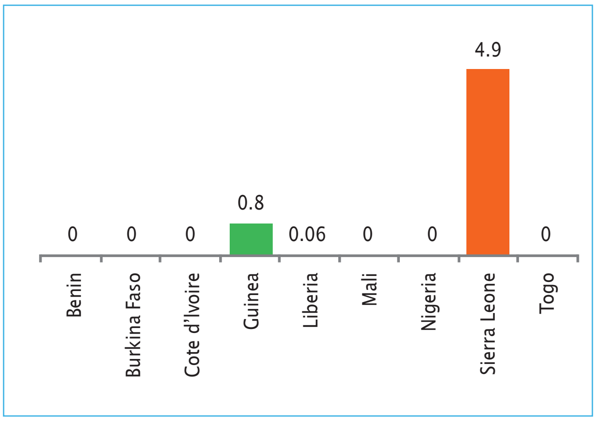


Source: *WSHPDR 2016*[5]
Note: Does not include countries with 0 per cent share.

Nigeria accounts for 50 per cent of the regional share of installed small hydropower (SHP) (Figure 1). Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, the region's total installed SHP capacity increased by 6.8 per cent from 82.5 to 86.1 MW (Figure 2).

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for Western Africa



Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting. This figure does not include countries with 0 MW of installed SHP.

Small hydropower definition

The definition of SHP varies throughout the region. However, most countries use the ECOWAS definition of up to 30 MW (Table 3). Ghana has the lowest upper limit for SHP with 1 MW. An overview of the country definitions of SHP is available in Table 2.

TABLE 1

Overview of countries in Western Africa (+/– % change from 2013)

Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Benin	10.6 (+17%)	56.4 (-0.6pp)	28 (+0.6pp)	85 (-12%)	N/A (-)	66 (-)	172 (-)
Burkina Faso	17.6 (+7.9%)	71.0 (-13pp)	16 (+1.4pp)	440 (+74.6%)	N/A (-)	32 (0%)	85 (-27.0%)
Cote d'Ivoire	22.7 (+5.0%)	45.3 (-3.7pp)	26 (-)	1,632 (+17.3%)	8,214 (+39.7%)	604 (0%)	1,913 (+18.2%)
Gambia	1.9	41.5	35 (-)	65	232	0	0
Ghana	26.7 (+9.8%)	46.4 (-37.6pp)	75 (+3pp)	2,831 (+30%)	12,963 (+15.7%)	1,580 (+3.3%)	8,387 (+35.2%)
Guinea	12.3 (+13.8%)	62.6 (-2.4pp)	26.2 (+12.2pp)	492.6 (+24.7%)	653 (-29%)	365.4 (+191%)	482 (-7.1%)
Liberia	4.2 (+7.3%)	50 (-30pp)	2 (-)	22.6 (0%)	37.3 (-)	4 (-)	N/A
Mali	17.1 (+17%)	60.2 (-19.8pp)	23.2 (-)	528 (+61.4%)	1,573 (+29%)	269.9 (+76.5%)	997.15 (+44.1%)
Nigeria	173 (+1%)	53 (-11pp)	48 (-2.6pp)	25,255.2 (-)	29,697.36 (-)	1,947 (+0.4%)	N/A
Senegal	13.6	61	56 (-)	620	3,037	66	740
Sierra Leone	6.3 (+23%)	60.3 (-1.7pp)	15 (-)	98 (-)	179 (+58%)	61.5 (0%)	82.3 (-17.7%)
Togo	7.1 (+16%)	60 (-20%)	27 (+7pp)	266.2 (+24%)	1,360 (+56%)	66.6 (+1.6%)	190 (+26.6%)
Total	**313 (+10%)***	—	—	**31,650 (-)**	**54,677 (-)**	**4,996 (+20%)***	**12,308 (-26%)***

Sources: Various[1,2,3,4,5,6,7,8,9]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.
*Gambia and Senegal are not included in the total per cent changes as those countries were not covered in *WSHPDR 2013*.

TABLE 2

Classification of SHP in Western Africa

Country	Small (MW)	Mini (MW)	Micro (kW)	Pico (kW)
Benin	10-30	1-10	10-1000	—
Burkina Faso*	—	—	—	—
Cote d'Ivoire	Up to 10	—	—	—
Gambia	Up to 30	—	—	—
Ghana*	Up to 1	—	—	—
Guinea	Up to 30	—	—	—
Liberia	Up to 30	—	—	—
Mali	1-10	0.1-1	< 100	—
Nigeria	1 to 30	0.5-1	100-500	< 100
Senegal	—	—	—	—
Sierra Leone	Up to 30	—	—	—
Togo	—	—	—	—

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
Note: For entries marked with an asterisk (*), see country reports for detailed definitions. The definition for Nigeria has been updated to match the 2015 National Renewable Energy and Energy Efficiency Plan (NREEEP).

Regional SHP overview and renewable energy policy

Most rural communities in Western Africa are not yet connected to electricity. Meanwhile, the ECOWAS white paper stipulates that up to 20 per cent of new generation additions in rural and semi-urban areas should come from renewable energy (RE) sources. Additionally, the ECOWAS Renewable Energy Policy set the goal to increase the share of decentralized rural renewable electricity services (e.g. mini-grids and standalone systems) to 22 per cent by 2020 and 25 per cent by 2030. The majority of ECOWAS member states still have difficulties in implementing these requirements.

TABLE 3

ECOWAS – ECREEE hydropower definitions

Terms		Power output
Pico hydropower	Small Scale Hydro Power (SSHP)	< 5 KW
Micro hydropower		5-100 KW
Mini hydropower (MHP)		100-1,000 KW
Small hydropower		1-30 MW
Medium hydropower		30-100 MW
Large hydropower		>100 MW

Source: ECREEE[7]

Grid extension, isolated mini-grids and standalone systems are adequate solutions to provide electricity access with socio-economic developmental objectives, including community and productive uses.

Isolated mini-grid solutions are required in many Western African countries that have limited national grid access in the rural areas as stepping-stones to grid-based access. In some cases, micro-grids are long-term solutions. Worldwide, the International Energy Agency (IEA)'s World Energy Outlook has projected that about 60 per cent of households not connected to grid at present would obtain electricity through such systems. The ECOWAS Renewable Energy Policy suggests that 128,000 mini-grids will be needed in the ECOWAS region to achieve the regional targets. Solar Home Systems are also suitable under certain conditions of isolation and level of socio-economic development.

Co-funded by the EU Commission, The ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) is leading and coordinating the implementation of 40 clean solar PV mini-grids in Senegal. ECREEE is also co-funding clean mini-grids in the Region (Cabo Verde, Guinea Bissau, Niger and Nigeria) under the implementation of the second Renewable Energy Facility for peri-urban and rural areas (EREF 2). Further mini-grid initiatives are the Electrification Financing Initiative (ElectriFI) funded by EU, the DFID-funded Green Mini-Grids initiative and the Renewable Energy for Poverty Reduction (REPoR), funded by the Islamic Development Bank (IDB).

With regard to hydropower, Benin has great potential, in particular SHP up to 30 MW and large-scale hydro, but also mini and micro units. The Nangbeto plant on the Mono River currently provides 65 MW of installed capacity, while the SHP installed capacity is 0.5 MW. Eight sites up to 30 MW are in the planning stages.[5]

In Burkina Faso, SHP is slated for an increase of installed capacity with at least seven projects on the way. Current plants, i.e. the Tourni (0.6 MW) and the Niofila (1.68 MW) provide 2.3 MW. The Tourni plant feeds energy along a 10.2 km distribution main to the Niofila plant, which then utilizes a 33 kV line (42 km) to supply the town of Banfora, providing electricity to some 30,000 inhabitants.[5]

There is a single operational SHP plant of 5 MW (or 55 MW depending if one includes the use the Ayame 1 and Ayame, drawing upon the 30 MW definition) in Côte d'Ivoire. However, the plant is currently in need of refurbishment. Studies conducted in previous years have identified the most promising hydropower development projects, with a total potential of 40 MW.[5]

Within the framework of the Gambia River Basin Development Organization (OMVG), hydropower projects are planed in neighbouring countries with benefits for the Gambia. Cross-border trade will be important to get out of the current situation of isolation in regards to the energy supply. There are five hydropower projects being planned or considered in conjunction with the OMVG that affect the Gambia, and forecasted for hydropower generation of 68 MW.[5]

In Ghana, the Sustainable Energy for All Action Plan 2012 set a target of 10 per cent of the energy mix from RE and to reduce the share of combustible RE sources to below 50 per cent by 2020. Currently, there are no SHP plants and there are no financial mechanisms specific for SHP. However, there are a number of incentives towards rural electrification as part of the National Electrification Scheme.[5]

The Government of Guinea has several plans for the development of SHP plants in its pursuit of increasing efficiency of and access to the grid. It developed

TABLE 4

SHP in Western Africa (+% change from 2013)

Country	Potential (MW)	Planned (MW)	Installed capacity (MW)	Annual generation (GWh)
Benin*	186.7 (158%)	73.2*	0.5 (-)	N/A
Burkina Faso	>38 (0%)	24.5	2 (0%)	N/A
Cote d'Ivoire	40.7 (+240%)	N/A	5 (0%)	5.4
Gambia	12	20*	0 (-)	0 (-)
Ghana	1,245.4 (-)	42	0	0
Guinea	198 (+230%)	110	11 (+10%)	N/A
Liberia*	65 (+14%)	>15	4 (0%)	N/A
Mali	117 (+1.7%)	21.6	5.7 (0%)	36
Nigeria*	735 (+99%)	30	45(0%)	N/A
Senegal	N/A	N/A	0	0
Sierra Leone*	330 (+634%)	10	11.2 (+78%)	N/A
Togo	144 (0%)	20	1.6 (0%)	2.6 (-)
Total	**3,111.8 (+319%)**	**258.4**	**86.1 (+4.3%)**	**(-)**

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
* indicates data is for < 30 MW SHP definition; otherwise data is for < 10 MW. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

hydropower plants in Tinkisso (1.65 MW) in order to generate electricity for the cities of Dabola, Faranah and Dinguiraye, and at Kinkon (3.2 MW) in order to generate electricity for the cities of Pita, Labe and Dalaba.[5]

The current installed capacity in Liberia (4.06 MW) is comes from two plants. One of these is a community-owned 60 kW plant and the other is a private concession-owned 4 MW plant. A number of SHP projects are currently being implemented and/or have been earmarked. The construction of a 1 MW Mein River plant is underway and a pre-feasibility study has been completed for a 10 MW St. John River Gompa Water Falls plant.[5]

In addition to the 5.8 MW of current SHP in Mali, seven priority sites have been identified and the evaluation of a further 10 additional micro hydropower sites is planned within the framework of the Master Plan Study for Rural Electrification financed by the African Development Bank.[5]

Nigeria has a new operational plant (Tunga) on the Donga River with an installed capacity of 0.4 MW. ECREEE, in collaboration with UNIDO, has developed the ECOWAS Small Scale Hydropower Program (2013-2018) for the West Africa Region, which has helped bring SHP capacity in Nigeria from minimal to 45 MW.[5]

While Senegal does not currently have any installed SHP plants, hydropower in general plays an important role in electricity generation for the country. Under the Organization pour la Mise en Valeur du Fleuve Sénégal (OMVS) framework, the 200 MW (104 MW available) Manantali plant in Mali provides Senegal, Mali and Mauritania with generated electricity. A lack of feasibility studies on SHP has hindered development in the sector.[5]

In addition to the 6 MW run-of-river plant in Sierra Leone, several plans are being undertaken to increase SHP installed capacity. The 2.2 MW project in Charlotte as well as the 2.2 MW project in Port Loko are both under construction and are expected to be online in the near future, while another at Makali (0.5 MW) is also underway. A Small Hydropower Technology Centre was also opened at Fourah Bay College.[5]

Even though Togo has only one SHP plant (1.6 MW) currently in operation, the Government is investing to change this reality in the foreseeable future. The Government has identified eight economically feasible sites, and of those three will be proposed for development under the Scaling Up Renewable Energy Programme, with an aggregate capacity of 20 MW.[5]

TABLE 5

ECREEE verified installed capacity and planned SHP in Western Africa (< 30 MW)

	Installed capacity (MW)	Planned capacity (MW)
Nigeria	32.4	21.4
Guinee	33.06	20
Sierra Leone	11.29	2
Cote d'Ivoire	25	19.5
Mali	6.3	104
Liberia	4.8	—
Burkina Faso	28.68	2.5
Togo	1.6	0.5
Total	**143.13**	**169.9**

Source: ECREEE[8]

Barriers to small hydropower development

While there is significant potential for SHP in West African countries, the widespread implementation of SHP is hampered by a number of barriers:

- Limited reliable discharge data over longer periods;
- Limited ongoing river flow measurements targeting assessment of small-scale hydropower in many areas;
- Limited practical flow measurement and hydrometric skills in many countries;
- Lack of safe and reliable data-handling regarding discharge data, precipitation data and reports;
- Insufficient attractiveness for investors in the past;
- Focus on medium and large hydropower in the last decades has minimized attention to the small-scale hydropower sector;
- Enabling environment slowly developing in all ECOWAS countries, driven by new regional support of ECREEE and national commitment.

1.5.1 Benin

Bill Clement, Ministry of Energy, Petroleum and Mining Research, Water and Renewable Energy Development

Key facts

Population	10,598,482[1]
Area	114763 km[2]
Climate	The climate in Benin varies from equatorial transition in the south to tropical and increasingly dry in the north.[24] The average maximum temperatures across the country vary between 28°C and 33.5°C (April to March) while the average minimum fluctuates between 24.5°C and 27.5°C (July to September).[2]
Topography	The country is fairly flat with five natural regions. The first of these is a coastal strip, low and sandy and limited by lagoons. The next is a central, hilly plain that rises gradually 200-400 m from south to north around Nikki, subsequently dropping to the Niger Valley and Kandi Basin. The third region is the Kandi Basin in the north-east, which is a plain drained by the Sota River and its tributaries, which flow in very flared valleys. The fourth region is the chain of Atacora in the north-west, where the highest point of the country is located, Mount Aledjo (658 m). Lastly, there are the vast plains of Gourma in the extreme north-west, between Atacora and the border with Burkina Faso and Togo. Moist savannahs occupy most of the country.[3]
Rain pattern	Two rainy seasons follow one another during the year, one between March and July and the other between September and November. Levels of recorded rainfall range from 850 to 1,300 mm, with the maximum in Donga and Ouémé.[2] Gradually, moving north, the Sahelian climate becomes more dominant, with a long dry season from October to April and one rainy season from May to September. Therefore, in the north, rainfall is lower (890 mm, except on the massif of Atakora, which receives 1,300 mm in Natitingou). In the south, the average annual rainfall decreases from Porto-Novo (1,200 mm) to Grand-Popo (820 mm).[24]
General dissipation of rivers and other water sources	The hydrology is divided into four major basins. In the north, the Niger Basin collects the water following tributaries from west to east. These include the Mekrou (410 km), Alibori (338 km) and Sota (250 km). In the north-west, there is the Volta Basin, that captures the Pendjari, which in turn captures the Kounné Rivers. The Kounné Rivers include the Tigou, Sarga Podiega, Magou and Yabêti. In the south-east, the Ouémé Basin captures the Zou, Okpara and other rivers. In the south-west, the Mono Basin and Sazué lead to a lagoon system at the bottom of the basin. This is because the Sazué has two tributaries, the Dévédo (22 km) and Savédo (40 km).[3]

Electricity sector overview

In Benin, the energy sector is highly dependent on biomass (firewood and coal) and relies on imports for its fuel and electricity needs. While the country has vast renewable energy (RE) sources, they remain significantly undeveloped. The regulating authority for the energy sector is the Direction General de l'Energie.

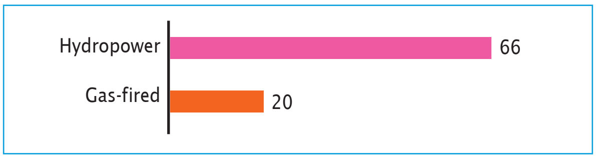
Energy consumption in 2010 was sourced mainly from biomass (38.89 GWh), representing 49.5 per cent. Fuel products supplied 48.2 per cent. Around 97 per cent of rural households rely on firewood for cooking. The amount of biomass used for energy purposes in Benin has caused a significant extent of forest degradation.[15]

The total installed electricity capacity is around 85 MW. 65.5 MW comes from the shared Nangbeto hydropower plant on the Mono River in Togo, and 20 MW is from gas turbines (Cotonou). The Nagbeto hydropower plant is owned both by Benin and Togo. According to the Benin-Togo Electricity Code, the two countries benefit from shared sources and utility management under the bi-national Communaute Electrique du Benin (CEB), which is primarily in charge of the production and importation of electricity for both nations.[6,14,18] In addition, the Benin-Togo electricity agreement allows for the potential available from the CEB to be split between the two nations, with 53 per cent going to Benin and 47 per cent to Togo.[14] Benin also has a small hydropower (SHP) plant with a capacity of 0.5 MW, the Yeripao hydropower plant, on its territory. However, the plant is currently offline. Since the capacity from the Nagbeto hydropower plant is taken in account in the Benin energy balance, the total installed hydropower capacity for Benin is considered to be 66 MW in this report.

In 2010, electricity consumption was 1,034 GWh. Eleven per cent of that consumption was supplied domestically by the distributor Societe Beninoise d'Energie Electrique, while 10.7 per cent was supplied domestically by the CEB. The CEB also provided 78.3 per cent of that consumption through imports from Ghana, Côte d'Ivoire and Nigeria.[4,20] In 2013, of the total electricity consumed (1,102 GWh) in Benin, the CEB provided 1,097 GWh (99.54 per cent).

FIGURE 1

Installed electricity capacity in Benin (MW) by source



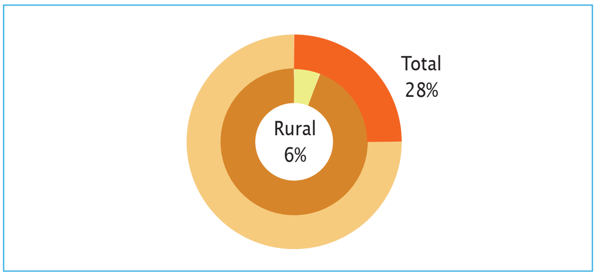
Source: CEB[5]

The CEB receives its supply of electricity from the Nagbeto Dam in Togo (65.5 MW), the Cotonou Gas Turbine (20 MW) and the Lome Gas Turbine (20 MW).[21] The import supply is from the Volta River Authority (VRA) in Ghana (10-90 MW), Sunon Asogli Power Limited in Ghana (20 MW), the Côte d'Ivoire Electricity Company (10-15 MW), Contour Global in Togo (30 MW) and the Nigerian Transmission Company (200 MW).[5]

The electrification rate in Benin in 2012 was 28 per cent. The rural electrification rate was 6 per cent and the urban electrification rate was 55 per cent. Electrification programs are overseen by the Agence Beninoise de l'Electrification Rurale et de la Maitrise de l'Energie.[7,8,19]

FIGURE 2

Electrification rate in Benin



Source: IRENA[19]

According to the African Development Bank and the Growth and Poverty Reduction Strategy for 2012-2015, a key development objective for Benin is increased electricity production. To achieve this, the 2012-2016 Country Strategy Paper outlined plans for the installation of a new dam, a 147 MW hydropower plant at Adjarala and the Maria-Gleta dual (oil/gas) thermal power plant in Porto Novo.[22] The Adjarala hydropower plant is expected to be completed by 2019, while the Maria-Gleta Thermal Plant is expected in 2020.[25] The installation of these two plants would nearly triple the existing installed capacity.[14]

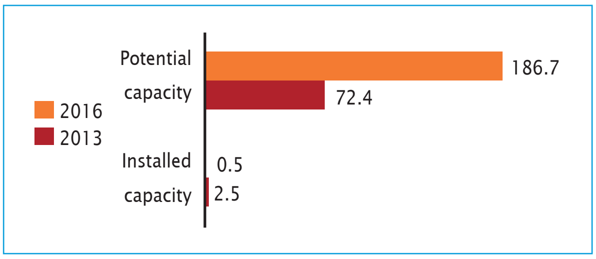
As of June 2015, the Government and the Millennium Challenge Corporation signed a power compact of a US$375 million to improve the country's power sector. A total of US$136 million will be used to increase domestic generation capacity, adding 45 MW of solar, 32 MW of thermal rehabilitation and 1 MW of run-of-river hydropower. A total of US$46 million will be used to increase the off-grid electrification rate in rural areas currently without access.[16]

Small hydropower sector overview and potential

Hydropower in Benin has great potential. The country has demonstrated interest in regards to large-scale hydro, but there is also potential with small and micro units. With regard to large hydro. The Nangbeto plant on the Mono River currently provides 65.5 MW of installed capacity, while the proposed Adjarala project could add 147 MW more.

FIGURE 3

SHP capacities 2013-2016 in Benin



Sources: *WSHPDR 2013*,[13] IED[8]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Benin has one SHP plant on its territory with a capacity of 0.5 MW, the Yeripao hydropower plant. However, it is currently offline. According to the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE), some three additional sites are in the planning stages (Table 1). The hydropower site of Beterou (Table 1) received a prefeasibility study in 1992. This study was updated in 2015 and the Beterou upstream site was chosen at the expense of Beterou downstream for environmental reasons.[26]

The official definition of SHP in Benin is 10-30 MW. However, different documents use alternative limits.[23] For the purposes of this report, the definition will be up to 30 MW of capacity, in coherence with the official definition. Since the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, there has been an update on the available date. As a result, installed capacity changed from 2.5 (as recorded in 2013) to the existing 0.5 MW for *WSHPDR 2016*. The potential capacity also changed from 72 MW (as recorded in 2013) to 186.66 MW in 2016[17] (Figure 3). The potential capacity for this report was calculated by summing up the potential capacity of the planned sites (Table 1), with the potential capacity in the identified sites (Table 2).

Various reports and feasibility surveys have produced potential sites for hydropower plants in Benin, ranging from micro to large scale. ECREEE has identified at least 10 sites that can be developed for SHP installations in Benin (Table 2).[17] Using the SHP definition of up to 30 MW, the potential capacity from these studies is approximately 113.46 MW.

TABLE 1

Planned SHP sites in Benin (up to 30 MW)

Planned site	River	Potential capacity (MW)	Potential production (GWh)
Assante	Ouémé	24.00	94
Dyodyonga	Mekrou	26.00	77
Bétérou	Ouémé	23.20	—
Total		**73.20**	**171**

Source: ECREEE[17]

TABLE 2

Potential SHP sites (0.01 MW to 30 MW)

Potential site	Potential capacity (MW)
Akpahogo	0.04
Avavi	0.13
Chute de Kota	0.09
Cove	13
Dekeossou	20
Djegbe	24
Okpa	29
Perma	0.20
Sokologbo	15
Zouka Tondi	12
Total	**113.46**

Source: ECOWAS[17]

Renewable energy policy

The Government of Benin is working on developing the RE sector.[11] Various policies and development programmes are going to be implemented. These include:

- Valorization of the hydropower potential through developing SHP plants where potential hydropower sites were identified within the rural electrification framework;
- Development and promotion of other RE sources (wind power, solar energy) in the framework of projects carried out by the government or by private investors;
- Development and promotion of modern biomass through raw agricultural materials (sorghum, sugarcane).

The strategy for the promotion of biofuels in Benin was adopted by the Government on 28 April 2012. Under this strategy, Benin could develop a production capacity of 1,150 million litres/year of ethanol and 229 million litres/year of biodiesel by 2025 to cover the domestic market. It could also include 10 per cent blends of bioethanol with petrol, as well as biodiesel with diesel, and substitute 15 per cent of wood energy in households with ethanol.[12]

In order to promote and develop these policies, the government created the National Agency for the Development of Renewable Energies. A feasibility studies phase conducted by National Agency for the Development of Renewable Energies was completed in 2015, and the country has moved on to finalizing a draft bill on biofuels.[28]

Barriers to small hydropower development

Several barriers to SHP development exist in Benin, including a lack of local hydropower equipment, supply, and an absence of local manufacturers. There is, however, potential for the establishment of a local hydropower manufacturing and reparation industry. It would need an institutional and regulatory framework that facilitates licenses, permits, authorizations and buyback tariffs. In conjunction with the hydropower potential, problems of low flow and drying rivers need to be considered. While there is a Rural Electrification Fund in place and electricity production has been liberalized, independent power producers have not yet explored the option of SHP and there is no feed-in tariff (FIT) for SHP in place.

1.5.2 Burkina Faso

Nathan Stedman and Gonzalo Marzal Lopez, International Center on Small Hydro Power (ICSHP)

Key facts

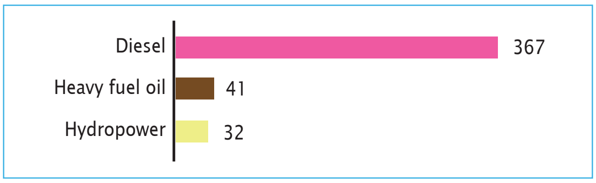
Population	17,589,198[1]
Area	274,220 km[2]
Climate	The climate is tropical and semi-arid desert (Sahelian region), characterized by two contrasting seasons (a rainy season and a dry season) coupled with two systems of winds (humid monsoon winds and dry, hot winds laden with dust). The dry season lasts eight months in the north and six in the south. Average temperatures vary between 27°C and 30°C in the south and 22°C and 33°C in the north.[2]
Topography	Most of the country is located on a central plateau, with steppe lands the most prominent in the north-east. The terrain is relatively flat. The average altitude is 400 m, with a range of 125 m to the south-east in the Pama region to 749 m at the peak of Ténakourou in the south-west.[2]
Rain pattern	The rain pattern varies per season and climactic region. The southern region is the wettest, which receives roughly 900-1,100 mm of rainfall annually. The northern region receives slightly less, at 700-900 mm. The Sahelian region is the driest, which only receives an annual average of less than 500 mm. National annual rainfall has decreased 5 per cent from 1990-2006.[3]
General dissipation of rivers and other water sources	The longest river in Burkina Faso is the Black Volta (1,352 km), located in the south-west. Two other principal rivers, the White Volta and Red Volta, run north to south in the central plateau region. All of the rivers flow southward and meet in Ghana to form the Volta River and Lake Volta. They are alternately dry or flooded and are all unnavigable.[2]

Electricity sector overview

In 2014, the total installed capacity in Burkina Faso was 440 MW. The majority of generation came from diesel while heavy fuel oil and hydropower produced the remainder (Figure 1).[11] The total consumption for the same year was 1,358 GWh with 488 GWh imported from Ghana, Côte d'Ivoire and Togo.[6] The country is reliant on imports of electricity and fuel to meet its electricity demand.

FIGURE 1

Installed electricity capacity by sources in Burkina Faso (MW)



Sources: IJHD,[6] ECREEE[11]

The Ministry of Mines and Energy, General Directorate for Energy directly controls the energy sector. The Regulatory Authority of the Electricity Sub-Sector (Autorité de Réglementation du Secteur Electricité) is the electricity sector regulator. According to Article 4 of Law No. 053-2012/AN (2012), the State controls production, transmission, distribution and sale of electricity. The Société Nationale d'Electricité du Burkina Faso (SONABEL) is the state-owned utility responsible for electricity in urban and semi-urban areas. SONABEL, along with the Electrification Development Fund (EDF), are the two companies which provide electricity generation and supply. Several independent power producers (IPPs) have also entered the market under concessions. These include EDENE, GG-Y, and BERCODE. However, the scope is limited.[3] EDF has primarily focused on small-scale solar PV projects, including installations on government facilities.[8] SONABEL represents Burkina Faso in the West African Power Pool, which is connecting and integrating regional power systems in the Economic Community of West African States (ECOWAS) region.

As of 2014, 16 per cent of the population had access to electricity. In urban centers, the electrification rate was 54.2 per cent, while in rural areas it was only 1.92 per cent.[12] Roughly 14 million people lack access to electricity.[8] Firewood remains a key component of residential life. Combined with increasing population growth, this has contributed to deforestation in some areas. The National White Paper for 2020 set an objective to increase urban electrification to 100 per cent and rural to 49 per cent, with 8 per cent of rural electricity supplied from solar sources.[17]

In the arid country, access to water is also a concern; the

Government Plan National Eau Potable et Assainissement (PNEPA) aimed to increase access from 60 per cent of the population to 80 per cent by 2015.[15]

The average electricity tariff paid by domestic consumers is US$0.18, one of the highest in sub-Saharan Africa.[6]

Small hydropower sector overview and potential

While there is no official definition of small hydropower (SHP) in Burkina Faso, SONABEL has used the limits set in Table 1 in official documents. For the purposes of this report, SHP will be defined as up to 10 MW of installed capacity. SHP installed capacity in Burkina Faso is 2.28 MW. The additional potential for SHP is at least between 24.52 MW and 36.2 MW as derived from studies and planned projects (Tables 1 and 2).[8,10] Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016,* installed capacity remained the same, while potential was significantly downgraded to reflect a more accurate number (Figure 2). It should be noted that many countries in the ECOWAS region use a SHP definition of up to 30 MW. In this regard, the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) has provided a SHP potential of 95 MW for Burkina Faso.[18]

TABLE 1

Hydropower classification and potential in Burkina Faso

	Production (P) [GWh/year]	No. of sites	Potential capacity (MW)
Micro hydro	P < 5	27	6.5
Mini hydro	5 < P < 15	29	29.7
Hydro	P > 15	14	101.8
Total		**70**	**138**

Source: Ministry of Mines and Energy[8]

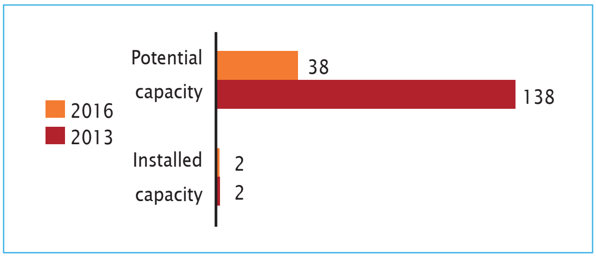
Total installed hydropower is 32 MW, which produces roughly 85 GWh of energy annually.[6] The overall hydropower potential is 138 MW, of which 75 MW are economically feasible. Currently there are four active hydropower plants, all of which are operated by SONABEL.[8]

The two operational SHP plants are the Tourni (0.6 MW) and the Niofila (1.68 MW). The Tourni plant feeds energy along a 10.2 km distribution main to the Niofila plant, which then utilizes a 33 kV line (42 km) to supply the town of Banfora, providing electricity to some 30,000 inhabitants.[9]

As indicated in Table 2, most of the planned SHP projects are located on the Black Volta. As one of the few perennial rivers in the country, the Black Volta will see an increase in installed capacity with at least the Samendeni and Bagre Aval projects being implemented in the near future.

FIGURE 2

SHP capacities 2013-2016 in Burkina Faso (MW)



Sources: *WSHPDR 2013*,[5] UNDP,[16] IWMI[10]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

TABLE 2

Planned hydropower projects in Burkina Faso

Name	Basin	Potential capacity (MW)
Samendeni	Black Volta	2.4
Nuombiel	Black Volta	48*
Arli	Oti	0.92
Bandongo	White Volta	3
Bagre Aval	White Volta	14*
Bon	Black Volta	7.8
Bontioli	Black Volta	5.1
Bonvale	Black Volta	0.3
Gongourou	Black Volta	5

Source: IWMI[10]
Note: An asterisk (*) indicates larger than 10 MW classification.

Renewable energy policy

The Government is currently reviewing national policies concerning renewable energy (RE). The development of the sector is a priority, as the 2020 objectives aim to reduce fossil fuel dependency while increasing access to electricity to a growing population. As such, the Government is planning to create a National Agency for Renewable Energy and Energy Efficiency.[8]

According to the General Regulation of the Electricity Subsector of Burkina Faso (Law No. 053-2012/AN), a concession is required for the development of any power plant over 25 kW (whether it uses renewable resources or not).[14]

The country's RE policy has been primarily focused on solar. In January 2013, a law of finance relating to customs duties was passed which exempted solar related equipment and material from customs charges and VAT. This law will be valid through 2018.[17]

Barriers to the small hydropower development

In the arid territory of Burkina Faso, the barriers to SHP development arise from both climactic and institutional sources. The irregular flows of rivers leaves some potential sites less than economically viable. Infrastructure development concerning water resources is primarily focused on access to water rather than hydroelectric production. Policy incentives have been centred more on solar PV as a RE source. As per the National White Paper for 2020, rural electrification should include at least 8 per cent solar, which the EDF has begun implementing.[17] In the absence of financial incentives such as feed-in tariffs and a lack of a clear path for private generators to gain access to the sector, it is likely that SHP development will remain low.

1.5.3 Côte d'Ivoire

N'guessan Pacôme N'Cho, Ministry of Petroleum and Energy

Key facts

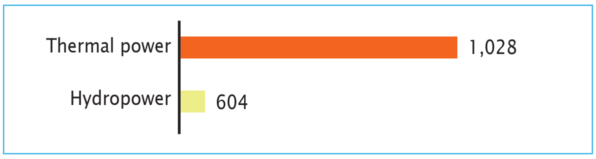
Population	22,671,331[1]
Area	322,632 km[2]
Climate	There are three main climatic regions. The equatorial coast in the south, tropical forest in the middle and semi-arid savannah in the north. The average temperature is between 25°C and 30°C and ranges from 10°C to 40°C. However, the country is generally subjected to large variations in temperature between the north and south, as well as throughout the year. The south is generally warmer with high humidity, at 80-90 per cent. The north is generally cooler with lower humidity, at 40-50 per cent. Temperatures in the north change by up to 20°C both daily and annually.[2]
Topography	The country 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 m. In the remainder of the country, elevations generally vary between 100 and 500 m while most plateaus are approximately 200 to 350 m.[2]
Rain pattern	The south has variable rainfalls of 2,100-2,500 mm. The middle central region has lower rainfalls of approximately 1,100 mm. The north is subject to a single rainy season from April to October, 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 (February to October) with rainfall of 1,600-2,300 mm.[3]
General dissipation of rivers and other water sources	The river system of Côte d'Ivoire has four main basins. These include the Cavally (700 km long with a drainage basin of 15,000 km²), the Sassandra (650 km long with a drainage basin of 75,000 km²), the Bandama (1,050 km long with a drainage basin of 97,000 km²) and the Comoé (1,160 km long with a drainage basin of 78,000 km²).[4] There are also a number of small coastal rivers, including the Tabou, San-Pedro, Niouniourou, Boubo, Agnéby, Mé, Bia and Tanoé, as well as other smaller rivers such as the Gbanhala, Baoulé, Bagoué, Dégou, Kankélaba, Koulda, Gbanlou, Gougoulo and Kohodio.[5]

Electricity sector overview

Biomass dominates the energy sector accounting for up to 70 per cent of overall energy needs.[6] Biomass fuels include charcoal for households, firewood for households, small restaurants, bakeries, and craft centres, as well as agricultural and forest residues for the production of steam and/or electricity in some agro-industrial companies and sawmills.

FIGURE 1

Installed electricity capacity by source in Côte d'Ivoire (MW)



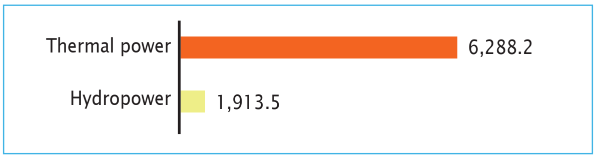
Source: CIE[7]

In 2014, there was 1,632 MW of installed and available capacity to the interconnected electricity grid. Hydropower contributed 604 MW (approximately 37 per cent) and thermal power plants contributed 1,028 MW (approximately 63 per cent) (Figure 1). The following Independent Power Producers (IPPs) developed 928 MW, or more than 90 per cent, of the total thermal power plant capacity: CIPREL (432 MW), AZITO (296 MW), AGGREKO (200 MW). There are also 61 remote stations with generators running on diesel that supply some localities from mini-grids.[7]

In 2014, the total electricity generated from all sources was 8,214.9 GWh. This comprised 1,913.48 GWh generated from hydropower, 6,288.21 GWh from thermal plants and 13.2 GWh from the remote stations (Figure 2). Electricity sales to countries in the local region amounted to 896.914 GWh.[7]

FIGURE 2

Annual electricity consumption by sector in Côte d'Ivoire (GWh)



Source: CIE[7]

The total electrification rate was 26 per cent in 2013 with 42 per cent in urban areas and approximately 8 per cent in rural areas.[17] The country has 8,513 localities, among which 3,682 were electrified by the end of December 2014. This represented a coverage rate of 43 per cent compared with 37 per cent in 2013. In terms of access, the rate of the population living in an electrified area was 77 per cent at the end of 2014 compared with 76 per cent in 2013.[4]

The number of subscribers to the low voltage electrical service increased by approximately 8 per cent between December 2013 and December 2014 from 1,215,310 to 1,311,740.[9] Based on this data, it is estimated that households with access to electricity was 31 per cent in 2014, compared to 29 per cent in 2013.

Within the framework of President Alassane Dramane Ouattara's proposal to make Côte d'Ivoire an emerging country by 2020, access to electricity is a major focus of economic and social policy. Given the importance attached to this issue, several actions are being implemented by the Government. These are supported by the establishment of a new Electricity Code adopted in March 2014.[10]

In an effort to facilitate the electricity connection of a larger number of households, the Government has proposed a set of measures, as part of the Electricity for All program, which will reduce initial fees and spread out the other costs over several years.[11]

Under the technical supervision of the Ministry of Petroleum and 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 Authority for Electricity Sector Regulatory (ANARE). CI-ENERGIES is responsible for the planning and implementation of investment projects while ANARE plays the role of the electricity sector regulator (monitoring of compliance with regulations and conventions, arbitration of disputes, protecting the users' interests).

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. This was renewed in 2005 and will be valid until 2020.

Three private operators (CIPREL, Azito Energie and Aggreko) are also involved in the sector as Independent Power Producers (IPPs). They operate thermal power plants fuelled by natural gas supplied by PETROCI-C11 and by Foxtrot International and CNR International through contracts of sale and purchase established with the state. In 2014, the electricity grid had a total length of 45,185 km. This was made up of low voltage lines measuring 18,737 km, medium voltage (15 kV and 33 kV) lines measuring 21,718 km and high voltage (90 kV and 225 kV) lines measuring 4,730 km.[7]

The Government has adopted a Strategic Development Plan 2011-2030 which covers the development of all sectors including the electricity sector.[12] Within this framework, several projects have been planned in regards to electricity generation, transmission and distribution infrastructure. At the Energy Department level, four master plans have been conceived (generation and transmission, distribution, rural electrification, remote control and automation) with the objective of providing coherent planning of the electricity sector's investments between 2014 and 2030.[9] The electricity base tariffs are fixed by the Government. Tariffs are the same for the entire country regardless of region (Table 1).[13] In addition to these base tariffs there are additional taxes such as the fee for rural electrification, the Ivorian Radio Television fee and local taxes that vary according to the electricity subscription and region.

TABLE 1

2015 electricity tariffs in Côte d'Ivoire (West African CFA Franc (US$) per kilowatt hour)

Tariff base	Cost (excluding 18% VAT)
Moderate household low voltage price (consumption ≤ 80 kWh by two-month period)*	36.05 (0.072)
Moderate household low voltage price (consumption > 80 kWh by two-month period)	62.70 (0.125)
General household low voltage price: 1.1 kVA (5 Amps)	63.17 (0.126)
General household price 10 Amps and more (up to 180 kWh/KVA)	63.17 (0.126)
General household price 11 Amps and more (above 180 kWh/KVA)	52.76 (0.106)
General professional low voltage price (up to 180 kWh/KVA)	78.46 (0.157)
General professional low voltage price (above 180 kWh/KVA)	66.73 (0.133)

Source: Inter-ministerial Order No. 569[13]
Note: An asterisk (*) indicates exempted from VAT.

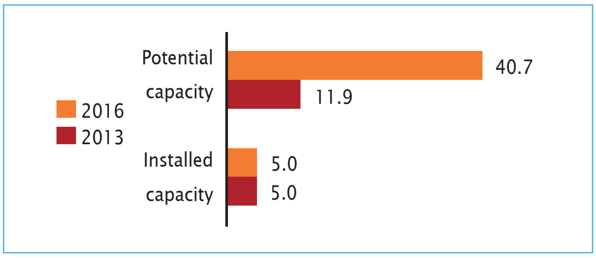
Following a cabinet meeting on 20 May 2015, the Ivorian Government decided to revise the electricity sales tariffs upwards after 1 June 2015. This increase is intended to ensure a sustainable financial balance of the electricity sector and to promote the necessary investments in network expansion and improvement in the quality of electricity supply, including the electrification of all localities by 2020. Forty per cent of social subscriber households will not be affected by this measure.[14]

Small hydropower sector overview and potential

The official definition of small hydropower (SHP) is less than 10 MW as adopted by the General Directorate of Energy. It should be noted that Côte d'Ivoire is within the ECOWAS region, which often uses a definition of SHP up to 30 MW. The country's 5 MW of SHP installed capacity has remained unchanged since the *World Small Hydropower Development Report* (*WSHPDR*) *2013*. Despite this, estimated potential has increased by approximately 250 per cent (Figure 3).[4,15,16]

FIGURE 3

SHP capacities 2013-2016 in Côte d'Ivoire (MW)



Source: Various[4,15,16]
Note: The comparison is between data *WSHPDR 2013* and *WSHPDR 2016*.

There is a single operational SHP plant, Grah, built in 1983 and currently in need of refurbishment. This accounts for 100 per cent of the country's SHP installed capacity of 5 MW, generating an estimated 5.41 GWh per annum and representing 0.83 per cent of the total hydropower installed capacity of 604 MW.[7] Using the definition of up to 30 MW, the total SHP installed capacity would be 55 MW, including the 30 MW (Ayame 2) and 20 MW (Ayame 1) plants.

TABLE 2

Potential SHP sites in Côte d'Ivoire with capacity less than 10 MW

Sites	River	Estimated output (MW)	Estimated annual supply (GWh)
Haut Bandama	Bandama	7.44	26.06
Ferkessedougou	Lokpoho	7.32	32.94
Aboisso	Bia	6.40	25.28
Korhogo	Lafigué	4.00	17.52
Téhini	Comoé	4.00	17.52
La Palé	La palé	3.50	17.50
Man	Drou	2.56	10.80
Laouguié	Agnéby	2.01	11.60
Fétékro	N'Zl	1.60	12.00
Séguéla	Banoroni	1.50	8.10
Daloa	Sassandra	0.17	0.58
Kassiguié	Agnéby	0.16	0.52
Total		**40.68**	**180.43**

Sources: CI-ENERGIES,[4] EDF[15]

Studies conducted in previous years have identified the most promising hydropower development projects. Table 2 consolidates data on sites with an estimated capacity less than 10 MW.[4,15] Based on these studies, dating back to 1979 (the only studies to date), the total potential capacity for SHP is estimated at 40.685 MW. This suggests that less than 11 per cent of Côte d'Ivoire's SHP potential has been developed.

Several large hydropower sites have been identified for a progressive development from 2017-2025. These are Soubré (275 MW), Singrobo (44 MW), Gribo-Popoli (112 MW), Boutoubré (156 MW), Louga (280 MW), Daboitié (91 MW) and Tiboto (180 MW).[9] For hydropower of all sizes there is a total potential for 1.85 GW installed capacity on the four major river basins, three times the current hydropower installed capacity.

Renewable energy policy

From 2013-2030, as part of the Strategic Development Plan 2011-2030, the Ivorian Government aims to increase the share of renewable energy (RE) to 5 per cent in 2015, 15 per cent in 2020 and 20 per cent in 2030.[11]

A call for expression of interest was launched in November 2013 and aims to provide electricity through the following services:

- Construction and operation of Build, Own, Operate (BOO) RE plants connected to the interconnected grid (SHP plants under 10 MW, biomass and solar under 50 MW);
- Construction and operation of photovoltaic BOO plants and an accumulation system with an electric mini-network or connected to the interconnected system;
- Construction and operation of biomass BOO plants with an electric mini-network or connected to the interconnected system;
- Construction and operation of hybrid BOO plants (biomass-solar-hydro) with an electric mini-network or connected to the interconnected system;
- Provision of energy services for the installation and operation of photovoltaic kits.

Apart from this, there are other specific RE policies.

Barriers to small hydropower development

One of the biggest barriers facing SHP development is the lack of new studies on potential sites. With new studies undertaken, it is likely that the estimated figure of 40.68 MW would be significantly greater.

However, due to the importance of the electricity sector for the country's economic recovery, more attention is being given to the potential of RE. It is likely that SHP in the country will benefit from this.

1.5.4 Gambia

Phillip Stovold, Citrus Partners LLP, Kaboni Energy Ltd.

Key facts

Population	1,991,000[1]
Area	11,300 km
Climate	South of the sub-tropical semi arid Sahel belt, Gambia has a tropical climate, with distinct wet and dry seasons. Temperatures generally increase from the coast towards the west, except in the rainy season (June to September), when all regions experience similar temperatures. In the hottest season (April to June), the inland regions have average temperatures of up to 35°C, while the cooler coastal regions are at 28°C. In the cooler seasons (October to December and January to March), average temperatures can go below 25°C at the coast and go up to 30°C in the west.[2]
Topography	The country follows the Gambia River basin. It is not wider than 48 km at any point and does not rise to more than 53 m above sea level. The Gambia River drops less than 10 m in its 470 km run from the far eastern border near Fatoto to the mouth of the river at Banjul.[3]
Rain pattern	The mean monthly wet season rainfall varies from 150 to 300 mm, between the northern and southern extremes. This rainy season is controlled by the movement of the Inter Tropical Conversion Zone (ITCZ). Rainfall has been reducing at an average rate of 8.8 mm per month per decade since 1960.[2]
General dissipation of rivers and other water sources	The Gambia River and its tributaries occupy 970 km^2 of permanent surface water area. During the height of the flood season, inland surface water, including the river, can extend to over 1,965 km^2 (about 18 per cent of the total area). The total renewable water resources in Gambia is estimated to be 8.0 km^3/year, of which 5.0 km^3 (62.5 per cent) flows into the country from Senegal and the Republic of Guinea. The surface water produced internally is estimated at 3.0 km^3 per year with annual internally renewable groundwater is estimated at 0.5 km^3.[4]

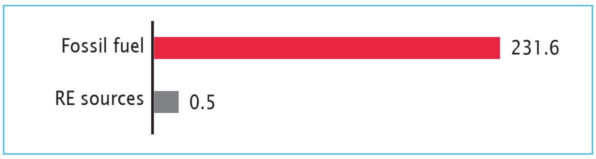
Electricity sector overview

Gambia relies on imported fossil fuel for electricity generation. The effective installed electricity generation capacity in 2013 was estimated to be 65 MW. This is supplied by two large Heavy Fuel Oil power stations. One is located in Kotu (25 MWp) and the other in Brikama (26 MWp). There are also the Batakunku and Tanji wind power plants (120 kW/150 kilovolt ampere (kVa) and 900 kVa respectively).[6] There is a separate system that comprises seven of the small-scale power plants owned by the National Water and Energy Company (NAWEC), that operate on diesel generator sets, served by stand-alone electricity subsystems in the provincial centres. Together, these small scale plants have an installed capacity of about 13.75 MW.[6] Approximately 250 km of 30 kV transmission lines are installed in the provincial grids plus 135 km of MV/LV lines and 94 km of LV overhead lines.[6] In 2012, total net electricity generation amounted to 232 gigawatt hours (GWh) against an estimated electricity demand of 621 GWh.[7] The share of renewable energy (RE) is negligible at 0.19 per cent and is mainly solar (Figure 1). There is currently no hydropower generation.

Electricity demand projections are expected to exceed 800 GWh by 2020, 1,219 GWh by 2030 and 2,514 by 2050. This gap between demand and supply is further exacerbated by technical grid losses of 23 per cent and over-all system losses of about 30 per cent.[8]

FIGURE 1

Electricity generation by source (GWh)



Source: Central Intelligence Agency[7]

The country's electrification access is about 35 per cent, concentrated in the Greater Banjul area where access is about 93 per cent.[3] In rural areas electrification falls to 6 per cent (Table 1).

Economic growth contracted from 4.3 per cent in 2013 to an estimated -0.7 per cent in 2014 due to the effects of Ebola on tourism related activities, the delayed rains experienced in 2014 and continued macroeconomic policy challenges. The Ebola epidemic in the sub region has had an adverse effect on tourism and related sectors, with hotel cancellation rates reaching 60 per cent for the 2014/15 winter season.[9] Macroeconomic policy slippages as evident in continued large fiscal deficits and heavy debt burden (estimated at 8.7 per cent and 100 per cent of GDP respectively, in 2014) continue to pose major challenges. Interest payments are responsible for approximately 22.5 per cent of government revenues.

TABLE 1
Electrification rate per region

Regions	Electrification rate
Banjul	93%
Western	22%
Upper River	14%
Lower River	12%
Central River	7%
North Bank Region	6%

Source: Ministry of Energy[6]

With 162 people per km², Gambia is one of the most densely populated countries in Africa, which exerts extreme pressure on the country's limited productive land and prevents social services from being adequately provided.[5,10] NAWEC has projected a need for an additional 210 MW of capacity by 2020.[6]

There are five key laws and policies in place that affect the energy sector. These are the Public Utilities Regulatory Authority Act of 2001 (PURA), the Energy Policy Act of 2005, the Electricity Act of 2005, the Gambian Investment and Export Promotion Agency Act of 2010, (GIEPA) and the Renewable Energy Bill of 2012. The electricity market was opened to the private sector following the 2005 Electricity Act, which was also intended to promote cost-effective generation, transmission and distribution of electricity, set standards for electricity services and determine appropriate tariffs. PURA designated itself as the authority responsible for licensing and tariff setting for electricity generation and sales, and developed a framework for the permitting process. The GIEPA provides incentives to enterprises and is intended to facilitate and promote additional electricity generation. Priority sectors include RE from solar, wind, hydro and biochemical energy as well as LPG and electricity generation, transmission and distribution.

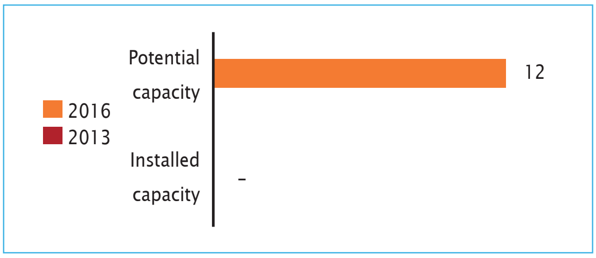
The Office of the President has final authority on regulations, tariffs and IPP contracting. The Ministry of Energy (MOE), under the Office of the President, is tasked with the responsibility for establishing the policy and strategies for the energy sector. This includes electricity, petroleum products and RE.

Small hydropower sector overview and potential

Small hydropower (SHP) is defined as up to 30 MW. There is no installed capacity of SHP in Gambia while the potential is estimated to be 12 MW for plants up to 10 MW (Figure 2).

The Gambia River is 1,150 km long, and has its source in the mountains of Fouta Djalon in Guinea. The Gambia River basin covers 99 per cent of the area of Gambia, 30 per cent of Senegal, 7 per cent of the territory of Guinea and less than 1 per cent of Guinea-Bissau.[12]

FIGURE 2
SHP capacities in Gambia (MW)



Source: IRENA[11]
Note: Data corresponds with up to 10 MW definition.

There are at least three hydropower projects, two of which are large systems, being planned or considered in conjunction with the Organization pour la Mise en Valeur du Fleuve Gambie (OMVG) that affect Gambia. These include:

- 93-MW Digan on the Gambia River;
- 82-MW Fello Sounga on the Tomine River;
- 20-MW Saltinho on the Koliba-Corubal River.

According to the Gambia River Basin Development Organization (OMVG), the projects will include feasibility studies, detailed design, preparation of tender documents and social-environmental studies, and technical assistance. The forecast for hydropower capacity for these projects will be at least 195 MW, although the project is still in the early developing stages.[16]

Within the framework of the OMVG, hydropower projects are planed in neighbouring countries with benefits for Gambia. Cross-border trade will be important to get out of the current situation of isolation in regards to the energy supply.[13]

The IRENA report: WAPP Planning and Prospects for Renewable Energy estimates that there is potential for 12 MW of small scale hydropower.[11] Although the SHP potential in Gambia seems to be very moderate due to the topographic situation, the Government of the Gambia in cooperation with UNIDO and ECREEE also looks into assessing possibilities to develop SHP particularly in the rural electrification context. The economics of SHP look very promising in comparison to the existing or planned diesel fired generation. Good potential sites on the lower Gambia River show several hours of velocities above 1 m/sec and peaks at about 1.5 m/sec. The upper part of the river is in strong need of data from velocity measurements.[14]

Renewable energy policy

The Renewable Energy Act of 2013 provides tax incentives for operators of facilities using RE resources for both power and non-power applications. It exempts projects producing electricity from RE resources, from corporate and value-added tax, for 15 years from the date of their commissioning.[15] The legislation also mandates the introduction of a feed-in tariff (FIT) system, to accelerate the development of RE sources.[16]

The Government is encouraging the use of the RE sources and has established Gambia Renewable Energy Centre. It seeks to collaborate with interested companies, individuals, development charities, research entities for the development of RE. At the present, utilization of solar PV equipment is increasing in the country, for industrial, commercial and domestic uses. The use of biomass is also on the increase, although it is confined to agricultural waste (e.g. sawdust, groundnut shells and straw). The use of the windmills for powering water pumps is also encouraged and is increasing through out the country. Wind power is under development. One 120 kW wind turbine is in operation (Batokunku), and one 6 MW wind park, known as Turjereng, is planned.[13]

Barriers to small hydropower development

Gambia has considerable RE resources, particularly solar, wind and biomass. However, only a small fraction of this potential is currently used. The power sector has experienced deterioration of its generation, transmission and distribution network, and does not yet have a fully functioning framework for IPP and RE projects to scale up on a commercial level.

The regulatory and permitting system has not been completed and the license pathway is not yet clear. With multiple agencies still involved in the IPP process, barriers to entry remain. This makes financing of projects difficult, due to the perceived financial viability of the off-taker NAWEC, and therefore, the likely bankability of projects. A standardized FIT has been proposed with a standardized 15-year power purchase agreement commitments, with indexation. This may allow developers and finance providers to quickly assess the risk and viability of projects, without the delay and uncertainty of long tariff negotiations. Prior to this, long and complex tariff and power purchase agreement negotiations for generation and distribution licenses have sometimes taken years without final conclusions.

PURA is yet to set rules for connection to the grid of RE projects, and has recently been advised by UNIDO to have legal advisers for distribution and regulation of grid connected electricity from RE sources.[17]

The regulatory and policy framework remain barriers to the investment and participation of independent power producers.

1.5.5 Ghana

Tom Rennell, International Center on Small Hydro Power; John Aurthur, Volta River Authority

Key facts

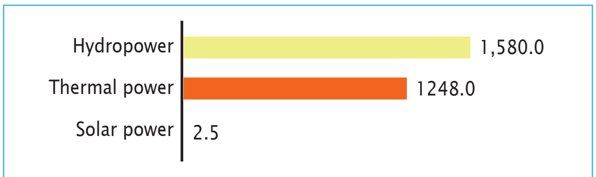
Population	26,786,598[1]
Area	238,533 km[2]
Climate	The climate is tropical but relatively mild for the latitude. Except for the north, there are two rainy seasons (April to June and September to November). Average temperatures range between 21°C to 32°C. In most areas, temperatures are highest in March and lowest in August. No temperature lower than 10°C has ever been recorded in Ghana.[2]
Topography	The country encompasses flat plains, low hills and a few rivers. The Volta Basin takes up most of central Ghana while the hilly Akuapim-Togo ranges are found along the country's eastern border, home to the country's highest point, Mount Afadjato at 885 m.[2]
Rain pattern	The annual rainfall in the south averages 2,030 mm but varies greatly throughout the country, with the heaviest rainfall in the south-west. On average, June is the wettest month, with rainfall of approximately 225-250 mm.[2]
General dissipation of rivers and other water sources	Almost all the rivers and streams north of the Akuapim-Togo ranges form part of the Volta River system. This includes the Black Volta and the White Volta Rivers, the latter of which is also fed by the Red Volta. The Volta is approximately 1,600 km in length and drains an area of approximately 388,000 km². The Black Volta and White Volta meet at the start of Lake Volta, which was formed after the construction of the Akosombo Dam. At 8,485 km², it is the world's largest man-made lake. To the south of the Akuapim-Togo ranges are several smaller independent rivers such as the Pra, Tano, Ankobra, Birim and Densu.[2]

Electricity sector overview

By the end of 2014, Ghana had a total installed capacity of 2,831 MW with approximately 56 per cent from hydropower plants and 44 per cent from thermal power plants. Other renewable sources such as solar provided a negligible amount (Figure 1).[3]

FIGURE 1

Installed electricity capacity in Ghana by source (MW)

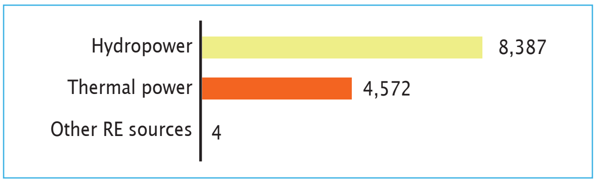


Source: Energy Commission of Ghana[3]

Total generation in 2014 was 12,963 GWh with hydropower contributing approximately 65 per cent and thermal power contributing 35 per cent. The contribution from other renewable sources was, negligible (Figure 2).[3] In the same year, electricity represented 13.6 per cent of final energy consumption, with 46.6 per cent provided by petroleum and 39.8 per cent provided by biomass.[3] All of the current hydropower capacity comes from three large hydropower plants, Akosombo (1,020 MW), Kpong (160 MW) and Bui (40 MW). Due to low reservoir levels, Bui is running significantly lower than capacity at approximately 113 MW. A further 179 MW of hydropower capacity is planned with the addition of three more plants: Juale (87 MW), Pwalugu (48 MW) and Daboya (44 MW).[4]

FIGURE 2

Annual electricity generation in Ghana by source (GWh)



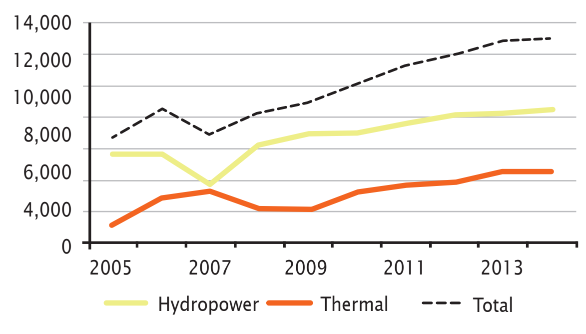
Source: Energy Commission of Ghana[3]

In the 10 years between 2005 and 2014, generation from both hydropower and thermal power plants has almost doubled, with generation from thermal plants increasing more than three times in that time and hydropower increasing by almost 50 per cent (Figure 3). Installed capacity in the same period has risen over 60 per cent.[3]

Despite this dramatic rise in capacity and generation, Ghana is failing to satisfy demand, experiencing frequent load shedding with rolling blackouts and brownouts. So frequent are blackouts that a new popular term, *Dumsor* (literally 'on-off' in the local Akan dialect), has been coined to describe the persistent, irregular and unpredictable power outages. The reasons given for the electricity shortages are numerous and are the subject of national debate but they include: disruptions from expansion and maintenance works, erratic supply of natural gas from the Jubilee Field and lack of payment to Nigeria Gas through West Africa Gas Pipeline Company (WAGPCo.), low water levels in the hydropower dams and the poor maintenance of existing plants and the transmission system. The latter is arguably a result of overly low consumer tariffs (see below). Nonetheless a key factor is likely to also be the rising levels of demand in the country.

FIGURE 3

Annual electricity generation in Ghana, 2005-2014 (GWh)

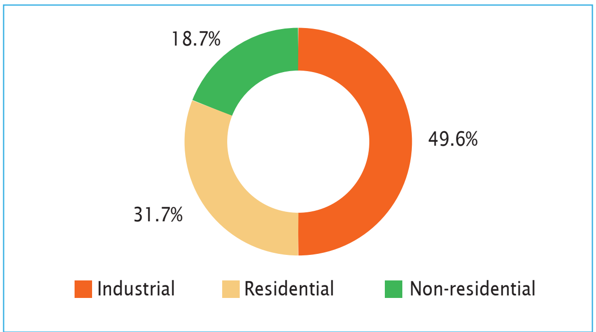


Source: Energy Commission of Ghana[3]

Electricity consumption in 2014 amounted to 10,182 GWh, an increase of over 90 per cent since 2005. Approximately 49.6 per cent was consumed by the industrial sector, 31.7 per cent by the residential sector and 18.7 per cent from the non-residential sector and street lighting (Figure 4).[3] On 1 January 2014, the Electricity Company of Ghana (ECG) recorded the highest ever peak load demand of 1,907.9 MW.[3] In order to eliminate the load shedding in 2015, the ECG predicted a minimum generation range of 16,398-17,350 GWh. Deducting the projected grid generation of 15,119 GWh this leaves a supply deficit of approximately 1,279-2,231 GWh, which is equivalent to providing approximately 200 to 300 MW of additional net capacity.[5]

FIGURE 4

Energy consumption in Ghana by sector (%)



Source: Energy Commission of Ghana[3]

In 1990, Ghana implemented the National Electrification Scheme (NES) with a goal of 100 per cent access by 2020 through six five-year phases, the last of which began in 2015. When the NES was implemented, Ghana had an electrification rate of 28 per cent. As of 2010, it was 72 per cent. The Greater Accra region on the southern coast, home to the capital city of Accra, had the highest electrification rate at 97 per cent. The neighbouring Central region and nearby Ashanti region were the only other regions to have an electrification rate above the national average, both above 80 per cent. The lowest rates of electrification were in the Northern, Upper East and Upper West regions, all of which were below 50 per cent. In the Upper West region, it was as low as 40 per cent. The NES is complimented by the Self Help Electrification Programme (SHEP), which aims to speed up the electrification process by encouraging towns and villages to help contribute to the cost of electrification. To qualify for the SHEP program, communities must be located within 20 km of an existing 33 kV or 11 kV source of supply, be willing and able to procure and erect the required number of standard LV poles and have at least 33 per cent of houses in community wired and ready for service.[6]

The Ministry of Energy is responsible for setting energy policy, including in the power sector. Prior to 2008, the Volta River Authority (VRA) was the state utility responsible for electricity generation, transmission and distribution throughout Ghana. As a result of the unbundling process completed in 2008, another state utility, the Electricity Company of Ghana (ECG), was established for the purpose of purchasing electricity from the VRA. Distribution is shared between the ECG and the Northern Electricity Distribution Company (NEDCO), a subsidiary of the VRA. Together they supply all of the country's electricity demand as well as some other West African countries. It is expected that NEDCO's responsibilities will eventually be transferred to the ECG to create a single national distribution company.

As part of power sector reforms implemented in 2005, the VRA's electricity transmission functions were transferred to the Ghana Grid Company (GridCo). GridCo is responsible for operation of the National Interconnected Transmission System, bulk power purchase of electricity from generators and sale to NED and ECG.

Prior to 2008, the Volta River Authority (VRA) was the state utility responsible for generation and transmission. Distribution had always been the sole responsibility of ECG until NED, now NEDCo., was established. NED was established when the Northern Electricity Distribution operations of the then Electricity Cooperation of Ghana were ceded to the Volta River Authority (VRA), at the time of extending the national grid beyond Kumasi to the northern parts of Ghana.

Ghana has two regulatory entities for the electricity sector. Generation licenses are granted by the Energy Commission, which is also responsible 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 sector (as well as gas and water), including the setting of tariffs. Table 1 gives a breakdown of electricity tariffs for different categories as of July 2015.[8]

Although under PURC tariffs have been slowly rising they are still below the cost of supply, resulting in the VRA and ECG being in precarious financial situations. This in turn has affected their ability to maintain and expand the system adequately, potentially contributing to the ongoing supply problems being experienced. Currently, the Government subsidizes the energy sector at great cost with approximately US$900 million spent on fuel subsidies for the VRA since 2004.[9]

TABLE 1

Consumer electricity tariff rates in Ghana

Tariff category	Rate (Ghanaian Cedi (US$) per kWh)
Residential	
0-50 kW (exclusive)	0.2108 (0.1260)
5-300 kW	0.4229 (0.2529)
30-600 kW	0.5489 (0.3282)
600+ kW	0.6098 (0.3646)
Service charge (per/month)	3.9772 (2.3780)
Non-residential	
0-300 kW	0.6080 (0.3635)
30-600 kW	0.6470 (0.3868)
600+ kW	1.0208 (0.6104)
Service charge (per month)	6.6287 (3.9633)
SLT – Low voltage	
Maximum demand (per/kVA/month)	37.1206 (22.1947)
Energy charge	0.6337 (0.3789)
Service charge (per/month)	26.5147 (15.8534)
SLT – Medium voltage	
Maximum demand (per kVA/month)	31.8177 (19.024)
Energy charge	0.4905 (0.2933)
Service charge (per/month)	37.1206 (22.1947)
SLT – High Voltage	
Maximum demand (per/kVA/month)	31.8177 (19.0240)
Energy charge	0.4508 (0.2695)
Service charge (per/month)	37.1206 (22.1947)

Source: PURC[9]

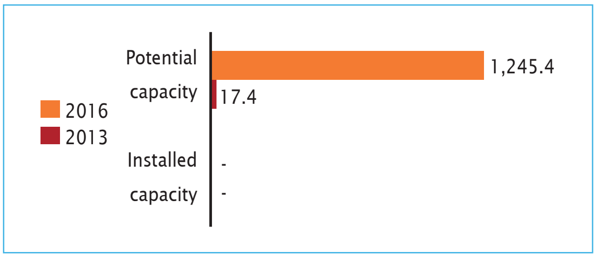
Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Ghana is up to 1 MW, with medium plants defined as between 1 MW and 10 MW and large scale as between 10 MW and 100 MW. There are currently no existing SHP plants in Ghana, although the Ministry of Energy estimates there is a potential for approximately 1,237 MW from sites below 10 MW with an additional 8.42 MW from sites below 1 MW.[10] In comparison to data from the *World Small Hydropower Development Report 2013*, the estimated potential is significantly greater for 2016 (Figure 5).[11] However, there still are no SHP sites to be developed.

According to the Ministry of Energy's estimate, the majority of medium hydropower potential is to be found in the Black Volta River basin. This constitutes approximately 55 per cent of the total (Figure 6).

FIGURE 5

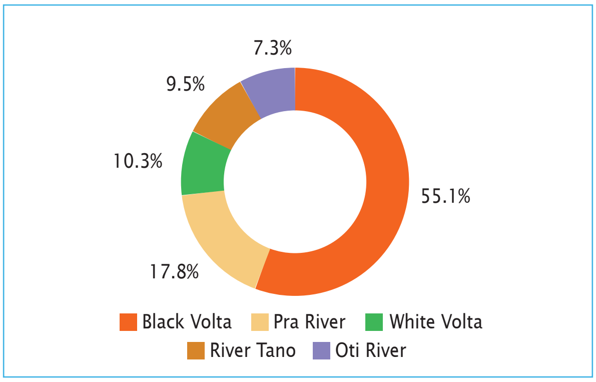
SHP capacities 2013-2016 in Ghana (MW)



Sources: Ministry of Energy,[10] *WSHPDR 2013*[11]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. The potential capacity for 2016 includes sites below 1 MW, and up to 10 MW.

FIGURE 6

Share of medium hydropower (1-10 MW) potential in Ghana by river system (%)



Source: Ministry of Energy[10]

A number of other studies provide various estimates of potential in different regions. According to the ECG's Strategic Energy Plan 2006-2020, there is a potential for approximately 25 MW over 70 sites with the Dayi River cascades in the Volta region identified as the most attractive site for development.[12] A report by the Ghana Energy Foundation suggests there is potential for 2.24 MW from 12 sites less than 1 MW and approximately 15.18 MW from 69 sites less than 2 MW.[13] For sites up to 30 MW, a report by the Economic Community of West African States (ECOWAS) estimates a total of 85 potential sites with a total potential capacity of 110 MW.[14] In 2015, the Small Hydro Development Corporation Ltd, a Ghanaian independent power producer, signed a US$164 million agreement with the ECG to develop 42 MW of SHP on the Ankroba River with work set to begin in 2017.[15]

There are no financial mechanisms specific for SHP. However, there are a number of incentives towards rural electrification as part of the NES including the SHEP (see above).

Renewable energy policy

The Government's Sustainable Energy for All Action Plan 2012 sets a target of 10 per cent of the energy mix from renewable energy (RE) and reduce the share of combustible RE sources (wood fuel) to below 50 per cent by 2020.[16] This is to be achieved through the provision of both grid-connected and off-grid facilities with the announcement that the Government had invested US$10 million to finance off-grid facilities for communities which could not be connected to electricity by virtue of their location.[17] To achieve this, the Government has specific targets to increase capacity from Resources by 2020 (Table 2).[18]

TABLE 2

Renewable energy installed capacity targets 2020

Programme	Preliminary target installed capacity by 2020
Feasibility study and the development of medium hydro potential sites	3-6 potential sites (200-300 MW)
Utility Scale Wind Park	150-300 MW
Utility Scale Biomass & W2E (Waste to Energy) power plants	50-100 MW
Utility Scale solar farms	50-100 MW
Distributed grid connected RE generation through Net-metering (solar, wind, biomass, hydropower)	30-50 MW

Source: Ahiataku-Togobo[18]

The principle legislation regarding RE is the 2011 Renewable Energy Law, Act 832, which aims to provide for the development management and utilization of RE sources.[19] In general, Act 832 aims to provide the fiscal incentives and regulatory framework to encourage private sector investment in the national RE sector. Key provisions include a feed-in tariff (FIT) and purchase obligation schemes.

The Renewable Energy Act gives PURC the responsibility to set FITs for RE technology. As of 1 October 2014, an FIT of 0.5362 Ghanaian Cedi (US$0.3206) per kWh was applied to SHP plants less than 10 MW, which is one of the lowest FITs available for RE sources (Table 3). These rates are applicable for a period of 10 years at which point they are subject to review by the PURC every 2 years.[20]

Under the Act, electricity distribution utilities or bulk customers are obligated to purchase a specified percentage of its total purchase of electricity from RE sources with the level to be specified by the PURC in consultation with the Energy Commission.

The Act also established the introduction of net-metering in January 2015 for facilities up to 200 kW allowing for RE generated to be delivered to the local utility in order to offset the cost of electricity provided by the utility.[21] A provision is also made for the establishment of a RE fund to provide financial incentives, subsidies and scientific, technological and innovative research as well as calling for the establishment of a Renewable Energy Authority to oversee the implementation of RE activities in the country. As of 2015, however, neither have been established. The duties of the Renewable Energy Authority are undertaken by the Renewable Energy Directorate under the Ministry of Energy until the Authority is established.

Small hydropower legislation

Apart from FIT, there is no specific legislation directly related to SHP. However, the 2010 Energy Policy does state the government's policy to "support the development of small and medium scale hydropower projects" on Ankobra, Tano, Pra, Oti and White Volta Rivers, as well as to create an appropriate fiscal and regulatory framework and to provide pricing incentives for SHP projects.[22]

TABLE 3

FITs for renewable energy in Ghana as of 1 October 2014

Renewable source	FITs (Ghanaian Cedi (US$) per kWh)	Maximum capacity (MW)
Wind with grid stability systems	0.5574 (0.3333)	300
Wind without grid stability systems	0.5143 (0.3075)	
Solar PV with grid stability/ storage systems	0.6441 (0.3851)	150
Solar PV without grid stability/storage systems	0.5836 (0.3490)	
Hydro (less than 10 MW)	0.5362 (0.3206)	No limit
Hydro (between 10 MW and 100 MW)	0.5389 (0.3222)	No limit
Biomass	0.5601 (0.3349)	No limit
Biomass (enhanced technology)	0.5904 (0.3530)	No limit
Biomass (plantation as feedstock)	0.6329 (0.3784)	No limit

Source: PURC[20]

Barriers to small hydropower development

Although the introduction of FITs for SHP aids in removing the barriers for private investment, Wisdom Ahiataku-Togobo, Director of Renewable Energy at the Ministry of Energy, has cited insufficiently favourable regulatory and fiscal regimes as significant barriers to the development of the renewable sector.[23] The FITs have also been criticized for being inadequate, for having too short a guarantee period (10 years), no green power priority rule and for being unclear on who bears the cost of grid connection and grid enhancement.[24] The tariffs are not strictly based upon the cost of generation either and, given the currently low levels of consumer tariffs, it is also unclear how the programme will be financed, potentially deterring more risk-adverse investors.

Inadequate financing of civil works is another deterrent to potential investment with many potential SHP sites situated far from grid connections. In some cases this has already proven to lead to project abandonment. In general, with the current energy crisis, government focus has been on much larger RE or thermal projects in order to provide a significant boost to the ailing capacity.[25]

1.5.6 Guinea

Mme Sow Aissatou Billy, Association Guinéenne pour la Promotion des Energies Renouvelables

Key facts

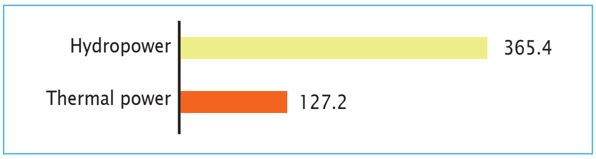
Population	12,275,527[1]
Area	245,857 km[2]
Climate	The climate is tropical, with a dry season lasting four to seven months and a rainy season of five to eight months. Average annual temperatures are between 21°C and 27°C. Maritime Guinea, including the capital Conakry, has its rainy season from April to October. Upper Guinea has a Sudanese climate, with temperature variations from 14°C during the rainy season to 37°C in the dry season.[2]
Topography	Maritime Guinea is the coastal strip between Guinea-Bissau to the north and Sierra Leone to the south (300 km) and is home to the largest mangroves in West Africa. Central Guinea is a mountainous region, yet the highest peak is in the Guinea Forest region, Mount Nimba at 1,752 m. Upper Guinea is has a low relief (average 500 m).[2]
Rain pattern	The annual rainfall varies between regions. Conakry and the Maritime Guinea receive upwards of 4,000 mm per year. Central Guinea receives 2,000 mm in the southern region and 1,300 in the north. The Guinea Forest receives roughly 2,500 mm while Upper Guinea receives 1,200 mm in the northern region.[2]
General dissipation of rivers and other water sources	Central Guinea is considered the water tower of West Africa because it is the source for many rivers: the Senegal and Gambia Rivers in the north; the Koliba Rivers, Rio Grande and Fatala Konkouré in the west; the Kaba and Kolenté in the south; and the Niger River to the east. This river system has its origins in two mountain ranges: the Fouta and the Guinean ridge. There are 23 river basins spanning the country.[2]

Electricity sector overview

While Guinea has enormous hydropower potential and some of the largest reserves of bauxite, the energy sector has not been developed extensively to pursue sustained development, due in large part to the political instability of the past. Recent years have improved, with development packages implemented by the World Bank, the African Development Bank and others to rehabilitate the electric grid in Conakry as well as to develop other areas.

FIGURE 1

Installed capacity in Guinea (MW)



Source: Sieguinee[12]
Note: Data from 2015.

In 2015, the installed capacity in Guinea was 492.6 MW, mainly from hydropower and thermal power plants. However, due to ageing systems and the need for rehabilitation, the available capacity was approximately 357.1 MW.[12] Electricity generation came mostly from hydropower (74 per cent), while the remaining was from thermal power. The total electricity generation was 653 GWh in 2013, with hydropower generation amounting to 482 GWh.[13]

The electrification rate in Guinea is approximately 26.2 per cent, with urban households having 74.2 per cent access to electricity and rural areas having 2.9 per cent access to elcetricity.[14] The Bureau d'Électrification Rurale Décentralisée is responsible for carrying out rural electrification projects. The following table represents the electricity tariffs in Guinea. While tariffs remain low, bill collection rates and illegal access to the grid have caused considerable losses to the sector.[6] It should also be noted that the majority of consumers in Guinea do not have meters, meaning that if they pay, they pay a lump sum.[10] Thus it is difficult to say how much they pay per kWh. Veolia Environnement S.A. is a French transnational company that won the contract to manage Guinea's struggling state-owned power firm, the Electricite de Gunee in 2015. In 2016, they tried to introduce pre-paid meters in Kaloum, the business center of Conakry. However, they were met by resistance from the local communities.[11]

Small hydropower sector and overview

Although Guinea does not have a small hydropower (SHP) definition, the government uses the definition used by the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE). It considers SHP to be plants with an installed capacity up to 30 MW. For the purposes of this report, the upper limit will be 10 MW. While reported data varies, SHP installed capacity in Guinea is estimated to be at 11.1 MW and potential capacity is at least 198 MW (including micro hydro capacities of less than 1 MW).[7] Since the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, installed capacity remained effectively the same while potential capacity more than tripled (Figure 2). The increase in potential is due in large part to feasibility studies and reevaluation of existing data in 2014.

TABLE 1

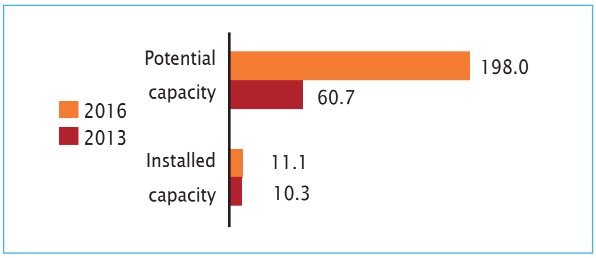
Electricity tariffs in Guinea (US $)

Household tariff	Tariff (US$)
1-60 kWh	0.01
61-330 KWh	0.03
More than 300 Kwh	0.04

Source: SE4ALL[6]

FIGURE 2

SHP capacities 2013-2016 in Guinea



Sources: AFD,[7] ECREE,[8] *WSHPDR 2013*[9]
Note: Potential is expected to increase with new studies/plans.
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

It is worth noting that the total hydropower potential (inclusive of large hydro) capacity of the country is estimated to be 6,000 MW, with more than 200 developable sites spread throughout the national territory. These estimates state that the annual energy of the potential capacity can be up 19,300 GWh.[8] As more feasibility studies are conducted, it is expected the potential for SHP will increase significantly.

The Government has several plans for the development of SHP plants in its pursuit of increasing efficiency of and access to the grid. In Moyenne Guinea, the development of the micro hydropower plants Touba, Danghora and Mongo II, will have a total capacity of 8.3 MW and generate 25.2 GWh. The government is also planning a micro hydropower plant in Bahayakrhoi, in Maritime Guinea, with a capacity of 1,500 kW and a generating capacity of 3,5 GWh/year. Also in production is the development of two micro hydropower plants, which are in the APS phase, located in Moyenne Guinee (Fulaso and Kokoulo Pont), with a total capacity of 4,700 kW and a productivity of 15.9 GWh. For a detailed list of micro hydro sites, see the *2013 WSHPDR* Guinea country report.[9]

Recently Tractebel elaborated reinforcement and refurbishment feasibility design studies on Touba (5 MW) in the prefecture of Kindia, Dabohya (2.7 MW) in the prefecture of Kindia and N'zebela (28 MW) in N'zerekore. The financial mechanisms available to carry out SHP projects are:

- A down payment from the operator ranging 5-20 per cent of the investment;
- A commercial credit from FERD covering 20-50 per cent of the investment;
- A subsidy from FERD up to 75 per cent of the costs.

TABLE 2

Installed SHP capacity in Guinea (MW)

Site name	River	Installed capacity (MW)
Banéah	Samou	5.00
Kinkon	Kokoulo	3.20
Tinkisso	Tinkisso	1.65
Samankou	Konkouré	0.39
Loffa	Ouin-ouin	0.16
Seredou	Labagui	0.64

Sources: AFD,[7] ECREE[8]

Renewable energy policy

The policies of Guinea regarding renewable energy (RE) in Guinea were started within the framework of reducing poverty according to the Targets of the Millennium Development Goals 2015. The national strategy for obtaining these targets is done through two several instruments. The Government of Guinea issued the Document de Strategie de Reduction de la Pauvrete and the Letre Politique de Development du Secteur de L' Energie, which highlight the folllowing policy targets:

- Develop 20 mini and micro hydropower plants before 2025, with five before 2017 in the form of public private partnerships or community projects;
- Develop in the form of public private partnerships 150 electrification systems;
- Put in motion an extensive program composed of 11 hydropower sites (Kassa B, Poudaldé, Gozéguézia, Souapiti, Amaria, Fomi, Kourou Tamba (Diaoyal), Bouréya, Kogbédou, Diaraguéla, Morisananko) mostly in the form of public private partnerships. These sites have a potential of 1,598 MW and will generate approximately 8,630 GWh.

Legislation on small hydropower

There is no established SHP legislation. However, in regard to the energy and electricity sectors, Law L/93/039/CTRN, regulating the production, transmission and distribution

TABLE 3

Potential SHP sites and status (MW)

Potential site	Status	Potenial capacity (MW)
Daboya	Approved	2.50
Touba	Approved	5.00
Bagata	Planning	1.20
Lokoua	Planning	6.00
Foko	Planning	2.50
Foungou-Banko	Planning	4.00
Nongoa2 (« Lokoua »)	Planning	9.00
Koutouya – N°38	Planning	9.00
N°70	Planning	10.00
Kamarato – N°64	Planning	10.00
Firaoua – N°7	Planning	9.00
Noungouro	Planning	8.00
Kinsi	Planning	6.00
Dombélé	Planning	8.00
Sita	Planning	10.00
Manguoy-Barkéré	Planning	10.00

Sources: AFD,[7] CEDEAO[8]

of electricity, as well as Law L/98/012 concerning BOT (Build-Operate-Transfer). Both of these helped to create an environment more suitable for private investment in the electricity sector. With the incentives in place, IPP's and PPP have helped to increase project proposals and investment in SHP.[8]

Guinea is also a member of the Niger Basin Authority (NBA), the Organisation for Development of the Gambia River (OMVG) and the Organisation for Development of the Senegal (OMVS). Each organization was established to facilitate policy making, utilization and preservation of the respective river basins.[2]

Barriers to small hydropower development

Small and large hydropower plants have been an important part of the electricity sector, justified by the importance of the development of the industry and mine sector. Guinea has a wide range of hydropower resources that can be developed in a sustainable manner to provide grid connected and non-connected areas with all the needed electricity supplies.[4] However, improvement must be made in the following areas:

- Capacity building: The lack of adequate infrastructure for research, planning, implementation and operation, including training of staff and supervisors of maintenance services of RE technologies in general and SHP in particular;
- Developing the country's hydropower resources, in particular by promoting synergies between the mining and energy sectors, and continuing regional integration;
- Upgrading the electricity grid to expand electricity access;
- Development of suitable and adapted legislation promoting the use of renewable energies including SHP as well as related implementation and creation of incentives;
- Further reforms in the electricity sector, with a view to achieving greater efficiency and encouraging private sector investment;
- Financial mechanisms: Lack of financial resources due to the complex permitting and licensing process for RE projects, with negative impact on the indices of development of RE and on technology transfer.

1.5.7 Liberia

M. Hady Sherif, Center for Sustainable Energy Technology

Key facts

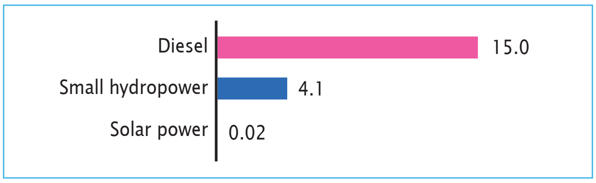
Population	4,192,000[1]
Area	111,370 km²
Climate	Liberia's equatorial position puts the sun almost overhead at noon throughout the year, giving rise to intensive heat in all parts of the country. Its temperatures range from 27°C to 32°C during the day and from 21°C to 24°C at night. Higher altitudes near the Guinean border in the north have a cooler climate.[2]
Topography	Characterized by mostly flat coastal plains rising to rolling plateaus and mountains in the north-east, the highest elevation is the northern highlands, which includes Mount Wutivi (1,350 m), the maximum elevation in Liberia.[1]
Rain pattern	There are two seasons: rainy and dry. The rainy season lasts from April to October. Average annual rainfall along the coastal belt is over 4,000 mm and declines to 1,300 mm at the forest-savannah boundary in the north. The months of heaviest rainfall are June, July and September. Overall annual rainfall ranges from 2,000 to 4,000 mm, with an average of 2,372 mm.[1]
General dissipation of rivers and other water sources	Water resources cover an estimated 200 km² of the surface area in Liberia. There are six major rivers flowing north to south. The drainage basins cover approximately 66 per cent of the country. These rivers are the Mano, St. Paul, Lofa, St. John, Cestos and Cavalla. Short coastal watercourses have drainage basins covering approximately 3 per cent of the country. They include—but are not limited to—the Po, Du, Timbo, Farmington and Sinoe Rivers.[1]

Electricity sector overview

The main source of electricity in Liberia is derived from 15 out of 221 MW units, which operate around the clock in Monrovia. The diesel units are managed by the only licensed utility company in Liberia, Liberia Electricity Corporation (LEC). The diesel plants are located on three sites: Bushrod Island has 15 units of I MW each, totalling 15 MW. Kru Town has 5 units, totalling 5 MW and Congo Town has 2 units totalling 2 MW.[19] Therefore, current installed capacity stands at 22 MW, of which 15 MW is available and active, providing electricity to the capital city, Monrovia, and its immediate environs. The remaining generation is powered by two small hydropower (SHP) plants. One of these is a community-owned 60 kW plant and the other is a private concession-owned 4 MW plant.[11] Remaining generation is also powered by small solar power systems, installed in 12 counties, with a total capacity of 24.51 kW, by the Liberia Energy Assistance Program (LEAP) (Figure 1).[18]

FIGURE 1

Installed capacity in Liberia (MW) by source



Source: USAID[18,19]

According to the Liberia Electricity Corporation (LEC), the total electricity generation between January and August 2014 was estimated at 37.3 GWh, slightly below the average annual energy production of 38.5 GWh between 2009 and 2013. The Liberia Investment Plan for Renewable Energy indicates that the LEC reports high commercial and technical losses ranging from 25-40 per cent.[3] This is supported by LEC's Year 4 Electric Master Plan, which reported losses of nearly 30 per cent by the end of the first quarter of 2013.

Electricity generation, transport and domestic lighting are highly dependent on fuel imports. Petroleum product imports between January and August 2014 came to 58 million US gallons or 8,429 TJ.[4] These products consist mostly of gasoline and diesel fuel and, to a lesser extent, jet fuel. Currently, the role of renewable energy (RE) is negligible. Significant captive power is also met by self-supply generation. Most larger facilities such as hotels, restaurants and office buildings self-generate electricity at their premises at levels estimated to be 10 times the existing installed generation capacity.[4] The country has a very low electrification rate of 2 per cent nationwide and about 7 per cent in the capital city.[5] The rural electrification rate is close to zero.

More than 90 per cent of the population relies on traditional, costly, and inefficient sources of lighting such as dry cell battery-powered lamps, palm oil lamps and small gasoline/diesel-powered generators Charcoal and firewood are used for cooking and heating. In the mid-2000s, the annual consumption of wood biomass was estimated at 10.8 million cubic metres of firewood and 36,500 tons of charcoal.[6] The United Nations Food and Agricultural Organization estimated a total charcoal production of approximately 243,286 metric tons in 2011.

The only public electricity supply currently existing in rural Liberia is the most recent cross border interconnection from Côte d'Ivoire. The project is expected to benefit an estimated 130,000 people in 18 small towns and villages. Though connections started in 2014, less than 1 per cent has been achieved so far.

Liberia's electricity infrastructure was almost completely destroyed during the 14 years of civil conflict that erupted in 1989. The total pre-war electricity generation capacity was 412 MW, of which 191 MW was provided by the LEC, who served about 35,000 customers. This was approximately 7 per cent of the population at the time. During the conflict, the 64-MW hydropower plant, located on Mount Coffee near Monrovia, was destroyed along with other thermal/diesel power plants owned by both government and private concessions. Public access to electricity subsequently became non-existent. With assistance from international development partners, the post-war elected government is still continuing to rebuild the electricity infrastructure.

The electricity sector in Liberia comprises three key governmental actors: the Ministry of Lands, Mines and Energy (MLME), the LEC and the Rural and Renewable Energy Agency (RREA). The MLME has an oversight role planning, formulating and implementing policies and regulations. The MLME is part of the board of directors of the LEC and the RREA. The LEC is a public corporation with the sole mandate to generate, transmit and distribute electricity throughout Liberia. Since 2010, it has been under a five-year management contract with the Canadian-based Manitoba Hydro International. The RREA has been operating since 2010 under an Executive Order issued by the President in response to the National Energy Policy (NEP). Its role is to facilitate and accelerate the economic transformation of rural Liberia by promoting the commercial development and supply of modern energy products and services to rural areas through both community initiatives and the private sector with an emphasis (though not exclusive reliance) on locally available, renewable resources.

Grid availability is yet to cover the entire capital city, let alone the rural areas. However, World Bank-funded projects, as well as other earlier donor-funded initiatives, are working to extend the grid coverage in the greater Monrovia areas and beyond. Rural grid access is limited to the areas so far connected through the cross border interconnection with Côte d'Ivoire.

Through the support of the United States Agency for International Development (USAID), the LEAP was implemented, which then established the NEP in 2009. Similarly, through the World Bank Climate Investment Funds' Scaling Up Renewable Energy Programme (SREP), the Investment Plan for Renewable Energy (IPRE) was developed in 2013. The Government has completed and finalized the Least Cost Power Development Plan (LCPDP) and embarked on an Energy Access Plan and Rural Energy Master Plan, among others. Current power generation and grid extension projects include:

- Rehabilitation of the Mount Coffee hydropower plant, which will provide 80 MW capacity, costing at least US$230 million. This was expected to be commissioned by the end of 2015, but has been delayed by a year due to effect of the Ebola epidemic.
- Construction of a total of 48 MW of heavy fuel oil thermal power to compensate for the high seasonality of hydropower. The commissioning of 20 MW was expected by mid-2015 but could also be delayed until the end of 2015.
- Construction of the 225 kV WAPP–CLSG (West Africa Power Pool - Cote d'Ivoire, Liberia, Sierra Leone and Guinea) Regional Transmission Line at US$494 million. Plans are also underway to extend the Monrovia grid and expand outside the capital, as well as to implement SREP in rural Liberia for feasible mini, micro and SHP, as well as biomass and solar power projects.[7]

There is no tracking system for national energy consumption or production. Electricity demand forecasts have also been challenging, given the limited development of power networks in and around Monrovia. Relying on previous forecasting efforts, the LCPDP provides 20-year electricity demand projections for three different scenarios (base, high and low) including the current unsatisfied demand but excluding the mining sector.[4] This forecast for electricity demand indicates a potential for fast growth at an annual rate of 10 per cent between 2013 and 2023. Peak load is expected to reach 311 MW by 2033 and the corresponding energy demand will be 1,672 GWh. Monrovia is expected to remain the primary load centre accounting for approximately two-thirds of the country's electricity demand.

With the inclusion of the mining industry, projected demand is estimated to be much larger. As of 2014, the Arcelor Mittal and China Union mining companies will require approximately 300 MW in the following five years. Similarly, the Putu Iron Ore and Western Cluster will require up to 400 MW in the following 10 years.[3] Depending on the price of iron ore and other exogenous factors, these companies could connect to the national power grid, if developed, to satisfy their demand.

Under the SREP's IPRE, a portfolio of nine mini-grid projects and nine stand-alone solar PV projects totalling 18.1 MW is being considered. The projects consist of one biomass plant of 1 MW, four SHP plants of 1 MW, three small hydro-solar hybrid systems of 1.5 MW, one biomass-small hydro hybrid of 2 MW and 9 stand-alone solar PV systems totalling 6.6 MW. Apart from the stand-alone systems, the above projects stand to feed to the LEC grid or CLSG regional transmission line substations so as to, among other things, achieve a geographic balance for electricity provision.

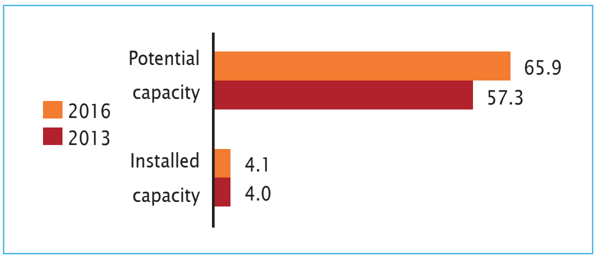
Electricity tariff constitutes fuel adjustment cost, generation tariff and Goods and Services Tax. The tariff is regulated by the board of the LEC. A single tariff is applied for all types of consumers based on a revenue requirement approach, which considers the revenues needed to meet all the utility's operating expenses and capital costs. Tariffs are calculated quarterly, considering the price of equipment, service schedule, maintenance, distribution costs and 20 per cent of technical and nontechnical losses. Liberia's current electricity tariff of US$0.56/kWh ranks among the highest in sub-Saharan Africa and the world. The cross-border electricity supply tariff stands at US$0.27/kWh, significantly lower than the main LEC tariff, while the tariff for the community-owned 60 kW hydropower currently stands at US$2.40 per 5 amp/month breaker per household.[8,9] The government is revising the tariff structure to support the investments needed to expand the electricity sector, while minimizing the tariffs' impact on the poor. The aim is to reduce the cost of electricity through a progressive shift of the generation mix away from diesel plants towards heavy fuel oil and renewable energies.

Small hydropower sector overview and potential

Liberia's definition of SHP conforms to that of the regional body, the Economic Community of West African States (ECOWAS), which is up to 30 MW.[10] Installed capacity of SHP in Liberia is 4.06 MW and the total potential is estimated to be at least 65.88 MW, indicating that approximately 6 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased only marginally by 1.5 per cent while estimated potential has increased by approximately 15 per cent (Figure 2).[11]

FIGURE 2

SHP capacities 2013-2016 in Liberia (MW)



Sources: LEC,[8] *WSHPDR 2013*,[11] Vilar[12]
Note: The comparison is between data from from *WSHPDR 2013* and *WSHPDR 2016*.

The current installed capacity of 4.06 MW comes from two plants. One of these is a community-owned 60 kW plant and the other is a private, concession-owned 4 MW plant.

The 60 kW plant is located in Yandohun, Lofa County in northern Liberia and was rehabilitated and upgraded to that capacity in 2013 by the RREA with funding (US$0.47 million) from the World Bank. Prior to the civil war, this was a 30 kW plant owned by an American PeaceCorp volunteer. The 4 MW plant has been operational since before the civil war and is owned and operated by the Firestone Rubber Plantation Company in Harbel, Margibi County.

The total potential SHP capacity of up to 30 MW is estimated to be 65.88 MW.[8,12] A number of feasibility studies were carried out over the period from 1976 to 1983 and at least 14 large-scale schemes were identified in the six main rivers indicating a considerable potential of up to 1,000 MW for all sizes of hydropower. Additionally, approximately 24 sites were identified by the LEC in 1988 for SHP power.[7]

A number of SHP projects are currently being implemented or have been earmarked. The construction of a 1 MW Mein River plant in Suakoko, Bong County in Central Liberia was underway and was expected to be commissioned in 2015. However, USAID announced a delay due to issues with the hired contractor.[14,15] It is expected to be community owned and operated and will serve approximately 2,500 households, 250 commercial entities, a university and a hospital. It is funded by USAID at a cost of US$5.8 million and the project is to be implemented by Winrock International and United Nations Industrial Development Organization. Additionally, a feasibility study for a 15 kW project along the Wayavah Falls in Lofa County has also been completed by the USAID in cooperation with Winrock International.[7,15]

As already noted, the RE projects designated under SREP includes 18 mini-grids totalling 18.1 MW. These include four 1 MW SHP plants, three 1.5 MW SHP-solar hybrid systems and one 2 MW biomass-SHP hybrid. The total cost for all 18 mini-grids is estimated at US$178 million. A number of prefeasibility studies have already been carried out. The most advanced, funded by Norway, is a study of the 1.5 MW Kaiha II project on the Kaiha River in the Lofa County. The power plant will be part of the mini hybrid grid with combination of hydropower, solar PV and diesel generation. The grid will serve Foya-Kolahun-Voinjama area, and the construction is due to commence sometime in 2016.[16] Additionally, according to the RREA, the six most interesting suitable sites for subsequent review and implementation under the SREP are Zeliba (Lofa), Lofa (Cape Mount), Ya Creek (Nimba), MR5 (between Cape Mount and Lofa), FR1 and Farmington (both in Margibi & Bassa).[3] Another two sites, Gbebin and River Gee, are also likely to be among the 18 sites, as a request for expression of interest has been made regarding conducting feasibility studies.[17]

Currently, as has been the case for most of the post-war electricity expansion programmes in Monrovia, most of the above-mentioned SREP SHP and other RE projects are funded through grants and low-cost/low-risk financing via credit lines from international, multilateral and bilateral development organizations and governments including the World Bank, the African Development Bank, USAID, the Government of Norway as well as the Liberian Government.

Renewable energy policy

Liberia does not have a validated and legislated RE policy document. However, the NEP was developed and approved by the Cabinet in 2009. According to the NEP, it is the policy of the government to facilitate and accelerate the economic transformation of rural Liberia by establishing a semi-autonomous agency. The agency should be dedicated to the commercial development and supply of modern energy services to rural areas, with an emphasis on locally available renewable resources. In response to the NEP, the RREA was established by an Executive Order in 2010 with legislation, including the establishment of the Rural Energy Fund (REFUND), passed and enacted into law in July 2015. According to the NEP, the REFUND will "provide for the coordinated and sustainable financing of projects and programs for the delivery of modern energy services for rural development. Once the REFUND has been established it shall become the channel through which all domestic and international financial resources intended for rural energy delivery in Liberia shall be managed".[13] The RREA shall facilitate the funding of rural energy projects, including managing the REFUND that will provide low interest loans, loan guarantees, and grants as targeted subsidies to ensure access by the poor. Passage of the RREA bill automatically implies passage and establishment of the REFUND. The REFUND Operating Guidelines have been developed and validated and are awaiting launch by mid-2015.

In 2007, a Renewable Energy and Energy Efficiency policy and action plan (RE&EE) was developed as a product of a project funded and co-funded by the Renewable Energy and Energy Efficiency Partnership and the government. It was submitted to the MLME for incorporation into the NEP. However, it was prepared prior to the preparation of the NEP and now seems limited due to the various developments over the years. If it is to be utilized, it will need significant improvement and revision to be validated, approved and legislated as Liberia's RE&EE policy.

The NEP, in line with the international community, states the following targets: reducing greenhouse gas emissions by 10 per cent by 2015, raising the share of RE to 30 per cent of electricity production and 10 per cent of overall energy consumption by 2015 and implementing a long-term strategy to make Liberia a carbon neutral country in energy production and transportation by 2050.

Liberia is a member of ECOWAS and a signatory to the white paper for a regional policy on increasing access to energy services for rural and peri-urban populations, the Energy Protocol that outlines principles for cross-border energy trade and investment and the West African Power Pool (WAPP) to address the issue of power supply deficiency within West Africa. Additionally, Liberia is a signatory to the United Nations Framework Convention on Climate Change and its Kyoto protocol. Lastly, it has also joined the United Nations Sustainable Energy for All Initiative.

Legislation on small hydropower

Apart from the NEP's prioritization and enhancement of the use of RE resources, including hydropower, there is no specific government policy on SHP.

Barriers to small hydropower development

In spite of all of the above, the main challenge to the SHP sector remains the inadequacy of legal and regulatory frameworks in RE which is crucial to developing the sub-sector and stimulating private investments. Other barriers include:

- Insufficient data on SHP resources and potential;
- Changes in land use patterns that may lead to changes in stream flow patterns in some locations;
- Limited legal and regulatory framework in the energy sector;
- Grid unavailability in rural areas;
- Limited human capacity or expertise in hydropower projects design, development and operation;
- Limited access to capital and financing.[4]

1.5.8 Mali

Zivayi Chiguvare, Namibia Energy Institute

Key facts

Population	17,086,022[9]
Area	1,240,192 km^2 [10]
Climate	Mali is an inter-tropical zone, which means it experiences hot and dry temperatures throughout most of the year. However, the country can be divided into three climatic zones: the desert zone, the Sahel zone and the Sudanic zone. The desert zone is encompassed by the Sahara, which has high temperatures of 47°C to 60°C during the day and low temperatures of 4°C to 5°C during the nights. The Sahel zone, which borders the Sahara, has temperatures averaging from 23°C to 36°C, and the Sudanic zone has average temperatures of 24°C to 30°C.[11]
Topography	The landscape is mostly flat, with rolling northern plains covered by sand and plateaus in the south. When the plateaus descend westward to the river valley, they turn into abrupt cliffs that reach an elevation of 1,000 m at Bandiagara.[11]
Rain pattern	The climate allows for a long dry season, lasting from November to June, and a rainy season from June to October. Rainfall ranges annually due to inconsistent climate change. In the Sudanic zone, rainfall can vary from 510 to 1,400 mm, while in the Sahel zone, it can vary from 200 to 510 mm.[11]
General dissipation of rivers and other water sources	There are two main rivers that cut through Mali: the Niger and the Senegal Rivers. The Senegal River and its tributaries flow in a north-west direction towards the Atlantic Ocean, cutting through Mali for 670 km. The Niger River flows flows in a north-east direction, across the Mandingue Plateau, until its course is interrupted by waterfalls and a dam at Sotuba. The river flows through Mali for over 1,600 km.[11]

Electricity sector overview

In Mali, electricity is supplied by Energie du Mali (EDM). The regulation and the supply of the electricity and water sector is assured in the urban centres by EDM, while rural off-grid energy service with generation systems below 250 kW are provided by independent operators through the Malian Agency for the Rural Electrification Development (AMADER).[1] The service provided by EDM is done in a steady way, with common tariffs for all the clients. However, services provided by the AMADER are limited daily, taking into account the number of hours agreed with the population. The number of hours varies from one location to another. This way of providing energy in rural areas has its positive points but it also has some drawbacks for rural consumers, because they have to pay higher tariffs than the ones applied by EDM.

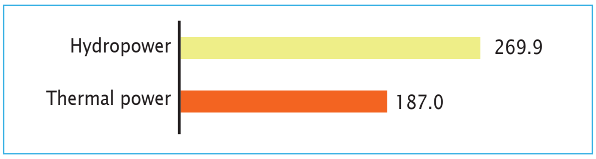
The EDM includes an Interconnected Network (RI) serving 32 localities. These include 19 centres (IC) that are based on isolated production and are independently distributed by the localities, as well as two centres that are part of the Ivorian network connected to medium voltage. The interconnected grid is composed by a 159 kV line connecting Bamako with the cities of Fana and Segou. The line originates at the hydropower plant in Selingue and consists of a a 63 KV line (222.4 km) connecting the cities of Segou and Niono as well as a 224 KV line with an origin in the hydropower plant of Mantali that connects the cities of Kayes and Kita.[2]

The EDM SA stated that in 2014, they operated 90.6 per cent of all the electricity power plants in Mali and generated 77 per cent of the urban population's electricity. Therefore, as of 2014, their overall national electrification rate stands at 23.2 per cent. This, however, does not include the electricity generated from the private sector or from small power plants that are not connected to the EDM SA.[4] Moreover, electrification in rural areas is very weak in Mali, with the latest data from 2013 stating that its electrification rate is only 15 per cent. However, the government plans to increase its focus in rural areas, and has set a target of 61 per cent electrification by 2033. It is also advocating isolated grids (in addition to interconnection) to meet this set target.[2]

The Malian grid is interconnected regionally with Mauritania, Senegal and Côte d'Ivoire. The interconnected grid is dominated by hydroelectricity, with 60 per cent production rate in 2012. Most of the hydro generation is attributed to the Manantali Dam (of which Mali owns 104 MW of the total 200 MW) and Selingue Dam, which have a capacity of 46 MW. However, there are smaller plants that also contribute to generation.[3] The total installed power capacity increased from 489.8 MW in 2013 to 528.1 MW in 2014, and this was largely due to the addition of a thermal plant installed in Darsalam (18 MW) and the addition of 15 MW of capacity due to the strengthening of interconnection with Côte d'Ivoire. As a result, the installed capacity for hydropower and thermal power was 269.9 and 187 respectively (Figure 1). The total electricity generation was at 1,573.886 GWh, with hydropower and thermal power generation at 997.147 GWh and 576.73 GWh respectively.

FIGURE 1

Installed capacity in Mali (MW)



Source: EDM SA[2]
Note: This only includes plants under the operation of EDM SA, and does not include generation of isolated grids.

In 2014, according to an EDM SA report, the total installed capacity by EDM of the interconnected grid was at 163.6 MW, while the total installed electricity capacity of Mali was at 528.1 MW. This total capacity includes isolated grids, the interconnected grid, the Organization for the Development of the Senegal River (OMVS) shared power plants, guaranteed imports and independent power producers. Table 1 demonstrates the total installed capacity.

TABLE 1

Installed electricity capacity in Mali (MW)

Interconnected to the grid			**Installed capacity (MW)**
EDM owned and operated	Sélingué	Hydro	47
	Sotuba	Hydro	5.8
	Darsalam	Thermal	29
	Balingué	Thermal	33.3
	IDB (Balingué)	Thermal	48.6
SOGEM shared under OMVS	Manantali	Hydro	104
	Felou	Hydro	27
SOPAM IPP	SOPAM	—	56
Côte d'Ivoire	Guaranteed capacity	—	45
Additional capacity (Darsalam, 18; Dakar, 40)		—	58
Isolated grids	21 grids	—	74.4
Total	—	—	**528.1**

Source: EDM SA[2]

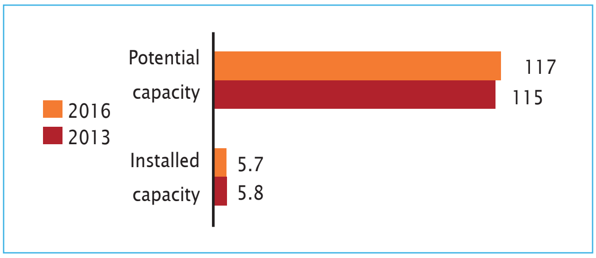
Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Mali is 1-30 MW. Mali has a SHP potential of 117 MW.[5] The SHP installed capacity in the country is 5.7 MW (Sotuba), which generates 36 GWh annually.[2]

According to the African Development Bank (AfDB), the potential for mini hydropower and SHP exists and several sites have been identified for its development. However, due to climate change, the Government of Mali wants to increase dependency on thermal power. Nevertheless, with the support of the Scale-up Renewable Energy Program (SREP), four micro and two mini hydropower plants are being developed, for an additional capacity of 14.6 MW.[2] Despite the government's reservations about hydropower dependency, it issued the National Energy Policy Letter in 2009 that lists projects to be achieved from 2009-2020. These projects include 133 MW of new large hydro projects and 100 MW of thermal capacity. Additionally, the AfDB has a few other micro and mini hydro projects under construction with co-financing from the SREP. This will contribute to an overall capacity of 21.6 MW upon completion.[2]

FIGURE 2

SHP capacities 2013-2016 in Mali (MW)



Sources: *WSHPDR 2013*,[8] African Development Bank[2]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

As of 2014, the country has a total hydropower potential of 1 GW, mainly from the flow of the Niger and Senegal Rivers, which have a combined flow potential of 56,000,000,000 m³ per year.[2]

Renewable energy policy

The Government, in the development of its energy policies, has chosen to support renewable energy (RE) for two crucial reasons: the availability of RE sources and the high price of the country's oil bill. For instance, Mali has a high number of sunlight hours per day (from 5.6 to 7 KWh/m/day). The targets for RE were set in the National Energy Policy in 2006 and complimented again by the Energy Policy Letter of 2009-2012.[6]

The government has also chosen to engage in several energy projects with international funding institutions like the World Bank, and the Climate Investment Funds (CFI). With the World Bank, the Government launched the Mali Energy Support Project. The project has a cost of US$120 million, with a five-year time frame, 2009-2012. It aims to:

- Improve the transmission and distribution of energy;
- Increase the energy efficiency and demand-side

management through efficient lighting in residential, streetlights, and public facilities;

- Engage in capacity and institutional strengthening for key sector institutions.

The government also launched the HUERA project in 2003 in conjunction with the World Bank. The project aims to increase the access of isolated low-income populations to basic energy services. The Government is also in the process of setting up a unit for the management of the SREP, financed by the CFI and the National Directorate of Energy.[6]

The regulatory environment is relatively favourable for energy investments in general. The energy sector has many assets that will favour the development of renewable energies through the SREP. In general, from an institutional and political perspective, key assets include the existence of core documents governing the sector and subsector (policies and strategies), the opening of the energy sector to private operators (with an important track record in rural energy access expansion over the last decade by decentralised energy services companies operating in public private partnership with AMADER), the opening of the national electricity grid to neighbouring countries (interconnection with Senegal and Mauritania, on-going regional interconnection with Côte d'Ivoire and Ghana-Burkina Faso), as well as a stated political will for the development of the sector.

Moreover, important progress has been made in the separation of the water and electricity sub-sectors and the reform of the EDM. The opening of the electricity subsector to competition has also contributed to increasing the effectiveness of the energy sector as a whole, speeding the withdrawal of the public sector from operation and expanding service coverage.

To develop the energy sector, the government recognises the value added by public-private partnerships for the development and scaling up of RE, in accordance with the principles of competition and performance-based rights. A framework for public/private partnership was set up in the form of BOOT concession contracts. A decree on the suspension of the value added tax, levies and duties on imported energy equipment is in place. It abolished these taxes for five years, starting in September 2009.[6] The Government of Mali is committed to scaling up RE development in an equitable way. The government-allocated budget for RE rose from US$3.3 million in 2008 to US$6.7 million in 2010.

Barriers to small hydropower development

Recent studies have shed some light with regard to the barriers for the development of SHP plants in Mali, as well as for the development of other renewable energies. These include:

- Incomplete legislative framework such as shortcomings in the investment code. Investors in the energy sector cannot benefit from tax free zone, nor do they have guarantees during site acquisitions.
- Uncompetitive business environment (not attractive enough to investors and private operators).
- Limited coordination among relevant institutions.
- Limited financial resources, which hinder RE access for the poor.
- Difficult return of investment due to an increase of investment costs and the need for an affordable price of KWh for poor households.
- Lack of a preferential fiscal and regulatory framework for RE.
- International private investors consider the energy sector in Mali as a risky sector.[7]

Note

The author, Sinalou Diawiara, was a staff at the Mali Minsitere de L' Energie et de l' Eau and is now retired.

1.5.9 Nigeria

Wim Jonker Klunne, Energy and Environment Partnership Programme

Key facts

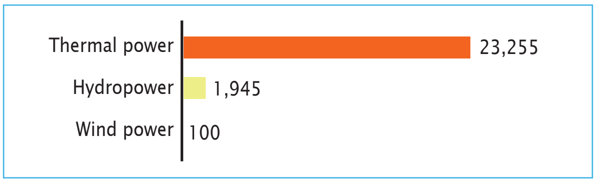
Population	173,000,000[1]
Area	924,000 km^2
Climate	The climate of Nigeria is monsoonal in character. Like other monsoonal climates, it features contrasting dry and wet seasons. These seasons are highly dependent on the two prevailing air masses blowing over the country at different times of the year: the dry north-easterly air mass of Saharan origin and the humid maritime air mass blowing from the Atlantic. The rainy season is generally between May and October. However, in the south, it tends to begin earlier, in either February or March. Average monthly temperatures vary from 30°C in April to 24°C in January.[2]
Topography	Nigeria has great topographical variety. Although much of the country is dominated by plains generally less than 609.5 m, the eastern border with Cameroon is marked by an almost continuous extent of mountains, the Eastern Highlands, that rise to about 2,419 m in the Chappal Waddi, the highest point in Nigeria. In the north, the Jos Plateau rises abruptly from a general height of approximately 609.5 m in the Hausa Plains to an average level of 1,219 m, reaching 1,781.6 m in the Shere Hills.[2] It should also be noted that 63 per cent of Nigerian land space is occupied by water.[18]
Rain pattern	The annual rainfall in Nigeria is highest in the coastal areas and decreases inland towards the north. The lowest levels are found in the northern borders of the country. The wettest areas are the riverine areas and the mid-western and rivers regions, close to the Cameroon border. The mean annual rainfall amount in these areas varies between 2,540 and 4,064 mm. The wet characteristic of the coastal and near coastal areas can be attributed to their nearness to the Atlantic Ocean. The moderately high rainfall in the plateau area can be directly related to relief or orographic effects. Rainfall in the dry season varies from less than 508 mm in the Niger-Delta to 0 mm in the Niger-Benue and the north.[2]
General dissipation of rivers and other water sources	The majority of its rivers flow towards the south, discharging into the Atlantic Ocean. They are largely dominated by the Niger and the Benue Rivers, which join up before forming the Niger Delta, one of the world's largest arcuate fan-shaped river deltas. Nigerian rivers generally show a marked seasonal variation in river stages and discharges. The distribution of average monthly water levels at some gauging stations show that a large proportion of the annual runoff occurs in the rainy season when the monsoon winds bring rains to swell the rivers, occasionally causing floods. During the dry season some of the smaller streams, especially in the northern parts of the country, virtually dry up. The bigger rivers are reduced to carrying only a small proportion of their rainy season discharges.[2]

Electricity sector overview

In 2013, electricity production was 27.03 TWh, with 63.3 per cent coming from gas, 20.9 per cent from large hydropower and 15.8 per cent from oil (Figure 1).[4,5] The total installed capacity in 2015 was approximately 25,255.2 MW. However, only 4,978 MW of the installed capacity is available, due to the need for rehabilitation of many power plants.[18] Most of the power stations in the country are fossil fuel based contributing approximately 81 per cent of the total installed generating capacity. The three major large hydropower stations, Kainji (760 MW), Jebba (540 MW) and Shiroro (600 MW) account for approximately 7.5 per cent of the installed capacity. The total annual electricity generation in 2014 was 29,697.36 GWh.[19]

FIGURE 1

Installed electricity capacity in Nigeria by source (MW)



Source: American Journal of Electrical and Electronic Engineering[18]

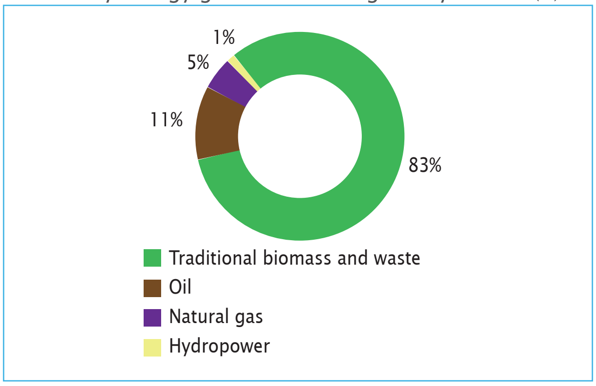
Nigeria has an electrification rate of 48 per cent, with a population of approximately 173 million and an annual growth rate of 2.8 per cent. Approximately 50 per cent of the population lives in rural areas with approximately 20 per cent with access to electricity.[5]

The electricity supply is presently unreliable in the country with frequent shutdowns, load shedding and grid failures. On average, consumers do not have electricity supply from the grid network for 10 hours every day. This has compelled many consumers (both industrial and residential) to buy diesel or petrol generating sets to meet their energy needs. The estimated electricity demand in the country is approximately 15,000 MW, while only approximately 5,000 MW is effectively operating. This is attributable to the current state of the grid network that is characterized by frequent overloading, system collapses and transmission and distribution losses of up to 30 per cent. Diesel and petrol generators are presently meeting the current gap in the demand and supply.

The primary energy generation in Nigeria is the burning of traditional biomass and fossil fuel. In 2011, the total primary energy consumption mix was dominated by traditional biomass and waste (83 per cent), oil (11 per cent), gas (5 per cent) and hydropower (1 per cent) (Figure 2).[16]

FIGURE 2

Primary energy generation in Nigeria by source (%)



Source: IEA[16]

The installed generating capacity of the country increased from approximately 6,000 MW in 2005 to 10,396 MW through the National Integrated Power Project (NIPP) initiative. Nonetheless, in 2013, the available capacity was 6,056 MW, while the energy demand was estimated to be 3,300 GWh.[6] The NIPP, conceived in 2004, is a fast-track government-funded initiative to stabilize Nigeria's electricity supply, while the private-sector led structure of the 2005 Electric Power Sector Reform Act (EPSRA) took effect. The NIPP was designed around gas-fired power stations in the gas-producing states with a cumulative power capacity of 5,222 MW. Notwithstanding the increase, the peak capacity generation is still approximately 4,978 MW as of 2015.[7,18]

The government has reformed the electricity industry and enacted several laws and regulations to develop the nation's abundant renewable energy (RE) deposits. The reform commenced with the preparation of a *National Electric Power Policy* (NEPP) in 2001, followed by the preparation and passage of the EPSRA into law in March 2005.[10] The NEPP planned a three-stage legal and regulatory reform for the electricity sector comprising:

- A transition stage characterized by private power generation via Independent Power Producers and Emergency Power Producers, corporate restructuring, unbundling and privatization of the National Electricity Power Authority (NEPA);
- A medium-term stage characterized by energy trading between generation and distribution companies on the basis of bilateral contracts;
- A long-term competition structure characterized by the optimal operation of the various power generation, transmission and distribution companies.

The EPSRA provides for the vertical and horizontal unbundling of NEPA into separate and competitive entities, the development of competitive electricity markets, the setting out of a legal and regulatory framework for the sector, a framework for rural electrification, framework for the enforcement of consumer rights and obligations and establishment of performance standards. With the passage of the EPSRA, the NEPA was deregistered and the Power Holding Company of Nigeria (PHCN) was incorporated to manage the unbundling of NEPA into 18 companies: 6 Generating Companies (GENCOs), 1 Transmission Company (TRANCOs) and 11 Distributing Companies (DISCOs). Together, these companies constitute the Nigerian Electricity Supply Industry (NESI), which is regulated by the Nigerian Electricity Regulatory Commission (NERC).

The restructuring broke the monopolistic framework of the power sector, allowing private operators to apply for and obtain a license through the NERC to build and operate a power plant with aggregate capacity above 1 MW. It also established the Rural Electrification Agency and an independent Rural Electrification Fund (REF), whose main objective is to fully incorporate renewable energy into the energy options.

In 2008, the NERC introduced a Multi-Year Tariff Order (MYTO) in its effort to provide a viable and robust tariff policy for the NESI, as well as the framework for determining the industry pricing structure. The MYTO provides a 15 year tariff path for the electricity industry with minor reviews bi-annually and major reviews every five years. New tariff classes under the 2012 Tariff Order were published by NERC as part of a summary of the MYTO-2 Retail Tariffs.[11] A review of this has also been released for 2015. There are three separate Tariff Orders, one for each of the sectors in the NESI namely: GENCOs, TRANCOs and DISCOs/retail. Tables 1 and 2 provide details of residential R2 category tariffs that came into effect on 1 July 2015, for four of the six DISCOS. This includes the expected increases for 2016, 2017 and 2018. The charges are in two parts, a fixed monthly charge and an energy charge for electricity consumption. Energy charges increased significantly from 2014-2015 to reflect the repayments of loans granted to all the DISCOS by the Central Bank of Nigeria.[12]

TABLE 1

Fixed monthly charges by DISCO 2015-2018

DISCO	Fixed monthly charge (Nigerian Naira (US$))			
	2015	2016	2017	2018
Benin	750 (4.50)	900 (5.4)	1,080 (6.48)	1,296 (7.78)
Ibadan	625 (3.75)	750 (4.5)	900 (5.40)	1,080 (6.48)
Ikeja	750 (4.50)	900 (5.4)	1,080 (6.48)	1,296 (7.78)
Eko	750 (4.50)	900 (5.4)	1,080 (6.48)	1,296 (7.78)

Source: NERC[12]

TABLE 2

Energy charges by DISCO 2014-2018

DISCO	Energy charge (Nigerian Nairi (US$) per kWh)			
	2015	2016	2017	2018
Benin	18.46 (0.111)	17.02 (0.102)	18.23 (0.109)	15.23 (0.091)
Ibadan	18.00 (0.108)	17.36 (0.104)	19.60 (0.118)	17.93 (0.108)
Ikeja	14.96 (0.090)	14.50 (0.087)	13.88 (0.083)	12.85 (0.077)
Eko	18.75 (0.113)	18.01 (0.108)	19.39 (0.116)	16.42 (0.099)

Source: NERC[12]

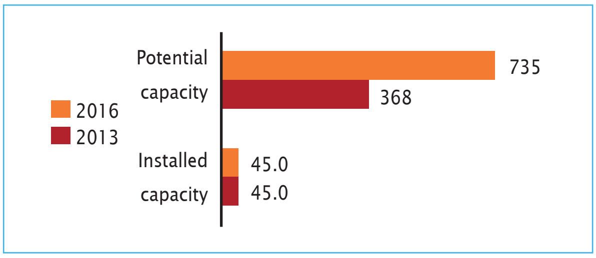
Small hydropower sector overview and potential

Small hydropower (SHP), according to the definition in the National Renewable Energy and Energy Efficiency Policy (NREEEP), is defined as 1 to 30 MW in Nigeria (Table 3).[13] Installed capacity for SHO is approximately 45 MW with an total estimated potential capacity of 3,500 MW indicating that only 1.3 per cent has been developed.[9] To ascertain the technical and economically feasible potential, data was compiled on planned and studied sites, which provided a total of 735 MW.[17] Compared to data from the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, installed capacity has remained the same but estimated potential has increased considerably (Figure 3).[3] It should be noted that since the previous report, at least one SHP plant (Tunga 0.4 MW) has been installed. However, the total installed capacity did not change as it is only an estimated total value.

Many studies, though concrete numbers vary, have stated that the hydropower potential, specifically SHP, is very vast in Nigeria, with 63 per cent of its land space being occupied by water.[18] The United Nations Industrial Development Organization (UNIDO) has focused on creating awareness among relevant stakeholders on the huge SHP potentials available in the country. In November 2002, the Energy Commission of Nigeria (ECN) collaborated with UNIDO and other relevant government parastatals to organize a national stakeholder's forum on RE technologies specifically based on SHP for rural industrialization with the aim of formulating strategies to provide access to clean and reliable energy services for Inclusive and Sustainable Industrial Development (ISID). A memorandum of understanding was signed between ECN and UNIDO and the International Center on Small Hydro Power (ICSHP) for further cooperation in harnessing the identified SHP potential.

FIGURE 3

SHP capacities (less than 30 MW) 2013-2016 in Nigeria (MW)



Sources: ICEED,[8] *WSHPDR 2013*,[3] A. I. Agbonaye,[17] IEA[9]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) in collaboration with UNIDO has also jointly developed the ECOWAS Small Scale Hydropower Program (2013-2018) for the West Africa Region. Prior to the intervention of UNIDO, SHP development in the country had been minimal. Approximately 45 MW of SHP has been developed so far, 70 per cent of which has been by the Nigerian Electricity Supply Corporation, an independent power producer.

TABLE 3

Categories of hydropower by installed capacity

Category	Installed capacity (MW)
Pico	< 0.1
Micro	0.1-0.5
Mini	0.5-1
Small	1-30
Medium	30-100
Large	> 100

Source: NREEP[13]

UNIDO's intervention includes establishment of the following pilot plants: Ezioha Mgbowo (30 kW) in Enugu State, Waya Dam (150 kW) in Bauchi State and Tunga Dam (400 kW) in Taraba State. The Tunga plant was operational as of 2016. SHP capacity has been developed in various higher institutions and river basins in the country. This has led to over 200 potential SHP sites identified, 17 feasibility studies with detailed project reports carried out and the development of three sites that are under construction which includes a 1,200 kW capacity SHP project in Benue State with donor support. Although 17 sites have bankable documents, private investors are hesitant to develop them as the investment costs are high and obtaining finance is difficult. In the 5th Global Environmental Facility (GEF-5) project cycle, 3.1 MW of cumulative capacity has been planned for implementation directly and to be replicated by private investors, to an estimated capacity of over 30 MW.[15]

UNIDO has facilitated the transfer of technology in manufacturing micro-hydropower turbines up to a capacity of 125 kW to the National Agency for Science and Engineering Infrastructure and the Project Development Agency. Under the same GEF-5 cycle, upscaling of local turbine and control system manufacturing to 300 kW capacity has been planned.

The Renewable Energy Master Plan launched in 2005 has a 10-year target (2007-2017) for increasing the contribution of RE technologies to the energy mix of the country. The initial targets based on peak supply from SHP were: 40 MW by 2007, 100 MW by 2008 and 400 MW by 2016. The targets were based on the assumption that over 200 identified potential SHP sites would be developed. However, achieving these targets has been a difficult task and only one of the targets has been met.[14]

There are a number of incentives for SHP construction. The EPSRA allows a person to construct, own or operate an off-grid power plant not exceeding 1 MW in aggregate at a site without a license. This exemption to holding a license favors energy generation through SHP since some of the identified SHP sites fall within the required range. It is also expected to encourage private sector participation to invest in small, mini and micro hydropower especially for rural development and off-grid generation.

Renewable energy policy

The Federal Ministry of Power has a renewed focus on rural electrification using RE sources, as a result of the successful privatization of the power sector. This project aims to create a conducive environment for independent power producers to invest in SHP plants which is in line with Nigerian Energy Policy, the Nigerian Renewable Electricity Policy, as well as the Renewable Energy Master Plan and Vision 2020, which aims to generate 6,000 MW of electricity by focusing on renewable and sustainable energy sources.[14] To develop the potential of its RE resources and achieve the Millennium Development Goals and National Economic Empowerment Development Strategy targets, the government has formulated numerous RE related policies including:

- The National Energy Policy, which contains RE, initiated by the Energy Commission of Nigeria and approved by the Federal Government in 2003;
- The Draft Renewable Energy Electricity Policy initiated by the Federal Ministry of Power in 2006;
- The Nigerian Biofuels Policy Incentives initiated by the Nigeria National Petroleum Company and approved by the Federal Executive Council (FEC) in 2007;
- The Vision 2020 document, initiated by National Planning Commission and approved by FEC in 2012 National Climate Change Policy initiated by the Federal Ministry of Environment and approved by the FEC in 2011;
- The National Environmental Regulation (2009, 2011) initiated by the National Environmental Standards and Regulations Enforcement Agency;
- The EPSRA of 2005, which liberalized the electricity sector, unbundled the PHCN in preparation to its privitization, and established the NERC as the sector regulator;
- Regulation on Independent Electricity Distribution Networks and Embedded Generation initiated by the NERC.

The feed-in tariff (FIT) for electricity from RE sources initiated by the NERC. The Renewable Energy Master Plan (REMP) is structured into the following programmes with short (2013-2015), medium (2016-2020), and long term (2021-2030) goals. Programs included under the Master Plan include: the National Biomass Energy Program, the National Solar Energy Program, the National Hydropower Programme, the National Wind Energy Program, the Emerging Energy Program and the Framework Program for Renewable Energy Promotion. The framework programme articulates issues that are common to all other sub-sectoral programmes and ensures that activities within the sub-sectors are mutually supportive.

TABLE 4

Renewable energy FITs 2012-2016 by source

Type of power plant	Wholesale contract price (Nigerian Nairi (US$) per MWh)				
	2012	2013	2014	2015	2016
Large hydropower	4,898 (29.39)	5,290 (31.74)	5,715 (34.29)	6,174 (37.04)	6,671 (40.03)
Small hydropower	23,561 (141.37)	25,433 (152.60)	27,456 (164.74)	29,643 (177.86)	32,006 (192.04)
On-shore wind power	24,543 (147.26)	26,512 (159.07)	28,641 (171.85)	30,943 (185.66)	33,433 (200.60)
Solar power	67,917 (407.50)	73,300 (439.80)	79,116 (474.70)	85,401 (512.41)	92,192 (553.15)
Biomass power	27,426 (164.56)	29,623 (177.74)	32,000 (192.00)	34,572 (207.43)	37,357 (224.14)

Source: NERC[11]

Financing is crucial to realizing the federal government's policy on RE and funding requirements will be substantial. New investments are needed for research and development activities. The required type of financing is long term and involves both foreign and domestic financing resources, though foreign investment capital will provide the greater proportion of needed funds.

The Government will provide guarantees and financial frameworks aimed at stimulating the expansion of the renewable electricity market. Considering the risks involved in financing renewable electricity projects, government investments should enhance rates of return and shorten pay back periods in order to attract investors. Additionally, the Federal Government should continuously improve the climate for enhanced funding of renewable electricity through equity, debt financing, grants and micro finance.[13]

To ensure a stable and attractive pricing policy for RE sources, the NERC plans to develop optimal FITs for SHP schemes not exceeding 30 MW, as well as all biomass co-generation, solar and wind-based power plants, irrespective of their sizes. It is expected that specific tariff regimes formulated by the NERC shall be long term, guarantee buyers under a standard contract and provide reasonable rates of return. NERC will also develop other tariff-related incentives and regulations to support renewable electricity adoption.[13]

Barriers to small hydropower development

The main constraints in the rapid development and diffusion of technologies for the exploitation and utilization of RE resources in the country are the absence of market and the lack of appropriate policy, regulatory and institutional frameworks to stimulate demand and attract investors. Though several policies and regulatory frameworks are in place to promote RE based electricity, there is no definite and well-framed pathway to make these policies successful. The comparatively low quality of the systems developed and the high initial upfront costs also constitute barriers to the development of markets. So far, the private sector is only involved in the importation and marketing of RE components. Full participation by the private sector in SHP development, especially in the form of investment towards local fabrication of turbines, will enhance the development of SHP potential. Additionally, the recent unbundling of the Power Holding Company of Nigeria into different companies under the privatization program has made acquiring related data challenging.

In addition to the above barriers, other barriers to SHP development include a lack of public awareness and participation through experience sharing, as well as insufficient skills and experience for developing SHP projects.

1.5.10 Senegal

Dione Constance, Ministère de l'Energie et du Développement des Energies Renouvelables

Key facts

Population	13,600,000[1]
Area	197,000 km[2]
Climate	The climate is tropical, with year-round average temperatures ranging between 26°C and 30°C, uninterrupted sunshine from November to May and a short rainy season between the months of June and October, with sudden but spectacular rainstorms.[1]
Topography	Known as the 'Gateway to Africa', Senegal is divided into three structural divisions: the Cape Verde headland in the west, which consists of small plateaus made of hard volcanic rock; the fringes of ancient mountain masses that include the highest point in the country on the southeast and eastern part of the country as well as a shallow but large landmass lying between the west; and the mountain masses to the east. Generally, the territory is flat and lies on a depression known as the Senegal Mauritanian Basin. Elevations of more than 100 m are found in the south-east and on the Cape Verde Peninsula. The Fouta Djallon foothills (shared with Gambia) are found in the south-west and rise to a maximum altitude of 581 m near the Nepen Diakhan. This is the highest point in Senegal.[7] The point remains an unnamed feature.
Rain pattern	The wet season, which lasts from June to October, is shorter in the north and longer in the south, especially near the south-west coast. The average annual rainfall ranges from 340 mm at Podor in the extreme north to 1,550 mm at Ziguinchor in the south-west. In the capital city, Dakar, the average is 570 mm. At Tambacounda and in the interior, it is 940 mm.[2]
General dissipation of rivers and other water sources	The main rivers are the Senegal, Gambia and Casamance Rivers. The Senegal River is considered the most important waterway since it has a long route through the interior of the country. It flows through the mountain masses of the east, rising at the Fouta Djallon foothills and rapidly falls before reaching Senegalese territory. The river then forms the Oula Delta, which supplies Lake Guier. In the south, the estuaries are muddy and salty, occasionally forming saline depressions known as tannes.[7]

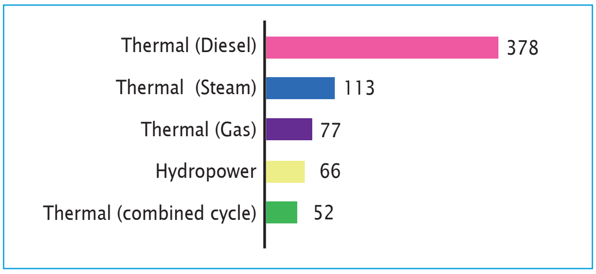
Electricity sector overview

Senegal recorded an electrification rate of 56.5 per cent in 2012, with 87.8 per cent of the urban population and 26.6 per cent of the rural population having access to electricity.[8] The total electricity installed capacity as of 2010 is around 690 MW, of which only 520 is actually available due to aging equipment.[3] Additionally, around 60 MW of electricity in Senegal is generated from the 200 MW (104 MW available) Manantali Hydroelectric Power Plant, found at the border of Mali. The Felou hydroelectric plant, shared with Mali and Mauritania, also generates electricity in Senegal (approximately 15 MW).[1] However, according to the German Federal Ministry of Economic Cooperation and Development, the electricity capacity in Senegal is composed of around 620 MW from thermal power and around 66 MW from hydropower.[3]

In 2012, peak demand reached approximately 466 MW and the generated electricity was approximately 2,800 GWh.[9] In 2013, available data stated that the total electricity production went up to 3,037 GWh, of which 2,186 GWh was from the interconnected grid operated by the Société National d'Éléctricité du Senegal (SENELEC) and 308 GWh from the Organization pour la Mise en Valeur du Fleuve Senegal (OMVS) hydropower plants Felou and Manantali.[1]

FIGURE 1

Electricity Capacity in Senegal (MW)



Source: The Deustche Federal Ministry of Economic Cooperation and Development (GIZ) GmbH[3]

Senegal has a Ministry of Energy and Ministry of Renewable Energy. The Commission de Regulation de l'Eléctricité is an additional regulatory body set up to approve concessions and investment plants for the power sector. It was set up under the energy liberalization legislation issued in 1998.[1]

As mentioned above, SENELEC is the public company operating the power sector. The company is vertically integrated and generates, transmits, distributes and sells electricity energy to the consumer. Additionally, the company identifies and finances new projects and has to maintain an autonomous self-financing system.

The Agence Senegalaise d'Éléctrification Rurale (ASER) is in charge of the rural electrification. In 2009, the agency reported the rural electrification rate to be approximately 19 per cent.[2] By 2012, the electrification of the rural population went up to 26.6 per cent.[8] The government has stated that electrifying the rural areas of the country is on the energy agenda.[2]

Small hydropower sector overview and potential

Senegal does not have any small hydropower (SHP) plants on its territory, nor does it have a definition for SHP. For the purposes of this paper, SHP will be defined as any hydro plant with a capacity below 10 MW. Due to the lack of SHP plants in the country, the potential of SHP has not yet been assessed.

The main hydropower plant, the Manantali Plant, is on the Senegal River near the border with Mali. This plant was developed in cooperating with Mali and the Mauritania within the OMVS framework. The hydropower plant has a capacity of 200 MW and projects to have a 42 per cent of capacity, thus, generating approximately 740 GWh per year.[2]

The Gambia River Basin Development Organization has developed the 128 MW Sambalaogulou project, which is to generate 400 GWh per year. In 2014, project consultants were invited to express interest in the Sambalaogulou project, which is to be built with an EPC contract.[1] Furthermore, the OMVG has completed the Kaleta Hydropower Plant, located in Guinea. The plant is in the process of completing the interconnection T-line which will allow supply to all 4 OMVG member countries (Guinea, Gambia, Guinea Bissau, and Senegal).[1,10]

Renewable energy policy

Senegal has attempted to reform its energy agenda to better promote renewable and sustainable energies. On order to achieve this, the Government passed the Renewable Energy Law, Phase 1 of the Senegalese National Biogas Programme, the 2007-2012 Special Programme for Biofuels, and the Program for the Promotion of Renewable Energies, Rural Electrification and Sustainable Supply in Domestic Fuel (PERACOD).[5]

The Renewable Energy Law provides a legal framework for tax exemptions for the purchase of equipment or materials necessary to develop renewable energy (RE) productions for domestic use. The law created the foundation needed for a feed-in-tariff (FIT) scheme.[5]

Phase 1 of the Senegalese National Biogas Programme has initiated the call for a diversification of the energy mix in Senegal, since its energy demands are on the rise and the country is heavily dependent on oil imports. The first phase seeks to install 8,000 biodigestors in three regions of the Peanut basin, (Fatick, Kaolack and Kaffrine), as sources for sustainable energy needed for cooking and lighting. The biogas waste is also intended to be used as manure for the agricultural productivity in the region, thus improving the efficiency of agriculture in the Peanut Basin.[5]

The 2007-2012 Special Programme for Biofuels is intended to improve energy independence, and achieve biodiesel self-sufficiency.[5]

PERACOD aims at increasing rural energy access through the deployment of domestic fuels and RE. It is a program that is being assisted by the German Development Agency.[4,5]

The commitments of the government, as demonstrated with the legislature above, are currently being tested by a process of agreeing and finalising the implementing decrees for these framework laws. However, it is clear that RE is viewed as both important in its own right and also as an enabler in the broader development of the energy sector, rural development and poverty reduction.

There are a number of institutions and frameworks dedicated to the further development of RE, notably the Centre for Studies and Research into Renewable Energy at the University of Dakar, and the National Energy for Solar Energy. More broadly, agencies such as the ASER, The Association Sénégalaise de Normalisation and the Commission de Regulation du Secteur de l' Electricity du Senegal include RE as a central part of their remit. Cross institutional cooperation has been facilitated by the establishment of an Inter-ministerial Committee on Renewable Energy (CIER) and the National Committee of Biofuels. Maintaining and extending this cooperation will enable ongoing success in the implementation of Senegal's vision for RE. In particular, efforts could be usefully directed at ensuring the participation of civil society. The domestic commitment to RE is reflected in the role that Senegal has assumed in regional and international forums. At the project level, there are any examples of cross-Sahelian initiatives in design and implementation. At the strategic level, Senegal has taken a central role in IRENA and ECREEE (ECOWAS Regional Centre for Renewable Energy and Energy Efficiency).

Barriers for small hydropower development

The International Renewable Energy Agency (IRENA) issued a report in 2012 pointing out the barriers and the recommended actions to develop hydropower and other RE sources. According to IRENA, the main barriers are:[6]

- Limited comprehensive mapping of RE sources in key areas;
- Need for Senegal to adapt the rules of intervention for the regulator in the specific case of small electricity producers;
- Need for Senegal to facilitate grid integration of electricity generated from renewable resources;
- Need to identify the conditions for increasing private sector involvement in RE related manufacturing.

1.5.11 Sierra Leone

Denise Tulcidas, Marcis Galauska and Nathan Stedman, International Center on Small Hydro Power

Key facts

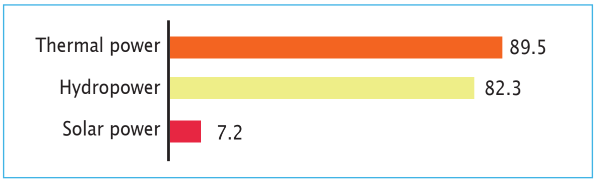
Population	6,315,627[1]
Area	71,740 km^2
Climate	Sierra Leona has a tropical climate with two seasons. The dry season (November to April) brings *harmattan* winds from the Sahara Desert and hits the country, resulting in sandstorms and little precipitation. The wet season (May to October) is characterized with winds from the southwest monsoon. Average temperatures vary between 25°C and 28°C.[2]
Topography	The western part (the Sierra Leone Peninsula) is a mountainous area that slopes down to the coastal plain in the east and extends inland for about 100-160 km. The north-east is characterized by stretches of wooded hills that lead to a plateau region (300-610 m). The highest point is Loma Mansa (Bintimani) at 1,948 m. 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.[2,3]
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: the coast to 80 km inland, with rainfall greater than 3,300 mm per annum; 80 to 190 km inland, with an average annual rainfall of between 2,500 and 3,300 mm; and 190 km inland to the border areas, with an average annual rainfall between 1,900 mm and 2,500 mm.[2,3]
General dissipation of rivers and other water sources	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 flow, which is lowest in April, as only 11-17 per cent of discharge occurs from December to April.[2]

Electricity sector overview

The energy sector in Sierra Leone is highly dependent on the use of imported petroleum (petrol, diesel, kerosene), hydropower and biomass (wood and charcoal). The total installed electricity generation capacity in the end of 2013 was 98 MW, with 179 GWh produced by thermal (oil), hydropower and solar PV (Figure 1).[17] Available capacity is lower due to the Kingtom and Blackhall Road power stations being in poor operating condition. As the nation is still recovering from war, the electricity generation, transmission and distribution infrastructure are still in need of maintenance.[5,11]

FIGURE 1

Electricity generation in Sierra Leone (GWh)



Source: Ministry of Energy[17]

According to a 2014 report from the Economic Community of West African States (ECOWAS), the national electrification rate was 15 per cent. In rural areas, only 1 per cent had access to electricity In urban areas, this increased to 38 per cent. The government has an energy target to reach 50 per cent electricity access by 2020, 75 per cent by 2025 and 100 per cent by 2030. Currently, most of the energy needs at the household level are met by the use of traditional sources such as wood and charcoal.[5,10]

Sierra Leone has great hydropower potential, enough to supply Freetown and to export excess electricity to its neighbouring countries.[5] The estimated potential is 1,513 MW (from 27 different sites, with most of them facing flow variations between wet and dry seasons). Only about 4.7 per cent of the hydropower potential in the country has been tapped so far.[12] In terms of generation cost, Yiben I and II, Bekongor III, Kambatibo, Betmai III falls are the most promising plants.[12] The 50 MW Bumbuna I plant came online in 2010 and in combination with other hydropower plants accounted for 57 per cent of total capacity in 2014.[10] A 2.4 MW plant (Guma) was decommissioned in 1982.[16]

The Government has projected a strategic plan in their National Energy Policy to increase electricity generation capacity to 1,000 MW by 2017. Another main objective of their National Energy Policy is to develop the energy supply infrastructure countrywide by developing alternative sources of energy without adversely affecting the five pillars of the 25-year Development Plan: an environment for economic and social development, good governance, improvement of national security, employment creation, and poverty alleviation. For the second and third stages of the energy expansion plan (by 2020 and 2025, respectively), 2 per cent of non-hydro renewable energy (RE) has been planned.[8]

The authority responsible for the electricity and water sectors is the Ministry of Energy and Power. They are in charge of policy formulation, planning and coordination and are also responsible for electric power supply, including matters related to renewable energies (hydro, solar and wind). The Ministry of Agriculture and Food Security is responsible for matters related to biomass, especially fuel wood.[6]

The National Power Authority (NPA) is the country's state-owned electricity provider and is responsible for the generation, transmission, distribution, supply and sale of electricity. The government has, in principle, repealed the Act of Parliament that empowered the NPA as the sole monopolist of electricity supply and now encourages private participation in electricity generation in order to restore power in areas with low electricity access.[4] In January 2015, in an unbundling aimed at encouraging private sector involvement, the Electricity Generation and Transmission Company and the Electricity Distribution and Supply Authority (EDSA) replaced the NPA. The Energy and Water Regulatory Commission will oversee the sector, enabling a separation of regulatory and commercial functions. The EDSA will operate as bulk buyer. Unbundling of the sector was established by the National Electricity Law approved in November 2011.[14]

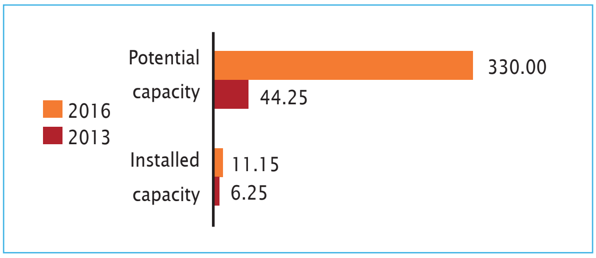
Sierra Leone is a member country of ECOWAS and their Centre for Renewable Energy and Energy Efficiency (ECREE) aims to develop the renewable energies and energy action plans of their country state member. Sierra Leone is also part of the West African Power Pool (WAPP), a regional organization dedicated to fostering greater cooperation in the region's power sectors and interconnection between countries to enhance energy security. Currently, Sierra Leone does not import electricity, although by joining the WAPP, the country has the potential to become both an importer and exporter of electricity and to compensate for seasonal variations in hydropower generation.[6]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Sierra Leone is installed capacity up to 30 MW.[10] Installed capacity of SHP is 11.15 MW, while the potential capacity is estimated to be 330 MW. This indicates that approximately 3 per cent has been developed.[16,17] Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016,* installed capacity has increased by 78 per cent (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Sierra Leone (MW)



Sources: *WSHPDR 2013*,[18] UNDP,[16] ECREEE[10]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The majority of installed capacity comes from the run-of-river Dodo plant (6 MW) and is operated by Bo-Kenema Power Services (BKPS).[16] Three new plants are under construction and will be complete by the publishing of this report. These are:

- The Makalie hydropower plant, with a capacity of 500 KW, which was jointly projected with the Chinese Government and is expected to be completed by the end of 2015.[13]
- The Charlotte Hydro Dam Project, with a capacity of 2.2 MW and also a grant by the Chinese Government, which will also be concluded by mid-2016.[13]
- The Bankasoka Hydro Dam, located by the Bankasoka River in New Port Loko town, which is under construction with a capacity of 2.2 MW. It is also expected to be completed by mid-2016.[13]

Sierra Leone has great potential for SHP generation. The government has a vision to develop all of its hydropower potential and to install thermal generation to complement the envisaged hydropower plants.[8] According to an ECOWAS RE report from 2014, the country has 330 MW of SHP potential.[10]

Since 2012, UNIDO has been working on a feasibility study for a 10-MW hydropower project linked to Njala University at the Moyamba district. In 2013 it was announced that the Moyamba hydro project, which is located at the Singimi Falls on the Gbangba River in Moyamba district, will be developed as a public-private partnership with the Government and will supply power to Moyamba, Njala University and Sierra Rutile.[14] The United Nations Industrial Development Organization (UNIDO) is financially supporting the National Government in this construction estimated at US$32 million.[15]

In addition to capacity, a Small Hydropower Technology Centre was opened at the Fourah Bay College (FCB), affiliated with the University of Sierra Leone. The centre opened after FCB signed a Memorandum of Understanding with both UNIDO and Global Environment Facility.[19]

Renewable energy policy

The Government announced the launch of the National Energy Policy Implementation Strategy in 2010 and set out plans for achieving the Renewable Energy goals established in the National Energy Policy.[6] It had planned to achieve 18 per cent of electricity generated from renewable energies by 2015.[10]

Currently, the government has several objectives regarding development and RE, which are set forth in the National Renewable Energy Action Plan (NREAP). Some of the targets include:

- Increasing installed RE capacity, reaching upwards of 659 MW by 2020 and 1,229 MW by 2030;
- Increasing access to RE via off-grid solutions including mini-grids;
- Increasing the number of households with solar heating systems;
- Blending bioethanol with petrol and biodiesel with diesel;
- Increasing the share of RE in the generation mix to over 25 per cent of total capacity by 2020, in large part due to hydropower.[17]

The Government has drafted a strategy in order to achieve these objectives. It plans to promote public-private partnerships for large RE projects by incorporating the surrounding community in the operation and ownership of the plant, establishing regulations for grid connections and adjusting tariffs. To promote private investment in small RE projects, the Government plans to establish power purchase agreements and clear policies for feed-in tariffs (FITs), as well as have tax incentives for importing RE equipment.[17]

Barriers to small hydropower development

Sierra Leone has several barriers for the development of SHP plants, these barriers can be grouped into:

- Political: Sierra Leone suffered from 11 years of war that caused economic damage and widespread destruction to the infrastructure.[9]
- Financial: There is a lack of financial investment and funds for SHP projects, caused in some way by the lack of incentives to attract investors.[5]
- Capacity Building: A network of gauging stations for regular water level and run off measurements and hydrological data collection is available at hydrological stations but there is still missing hydrology departments at universities and training institutes.[9] The absence of local experts, trained specialists for strategic planning, operation and maintenance in this field are also a constraint.[5]
- Technical: There is a lack of local production of equipment, turbines and spare parts.[9]
- Institutional: Absence of legal and regulatory framework, energy policy and local consultancy capacity.[9] According to AfDB (2011) the country has one of the highest electricity tariffs in West Africa.[5]

1.5.12 Togo

Eric Davy, Tcharadabalo Abiyou

Key facts

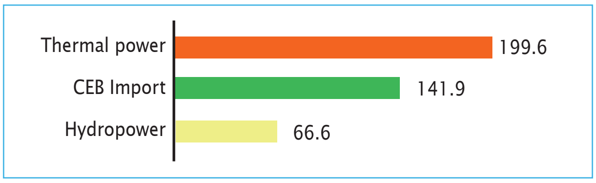
Population	7,115,163[1]
Area	56,785 km^2
Climate	The climate is tropical, hot and humid in the south and semi-arid in the north. Average temperatures vary from a minimum of 13°C-23°C to a maximum of 30°C-34°C.[2]
Topography	The terrain comprises gently rolling savannah in the north, central hills, southern plateau, low coastal plain with extensive lagoons and marshes. Its average height is 700 m above sea level, with the highest point in the Togo mountains at the peak of Mount Agou (986 m).[2]
Rain pattern	In the north, there is one wet season (May to November) and one dry season (December to March, when the *harmattan* wind blows north-easterly). The south has two wet seasons, one from March to July and another shorter wet season from September to November. The northern and central regions receive 200-300 mm of rain per month in the peak months of the wet season (July to September). The average annual rainfall in coastal areas is 950 mm.[2]
General dissipation of rivers and other water sources	Lake Togo is the largest of the inland lagoons lining the coast and is also the country's largest natural body of inland water. The Mono River flows north to south, traversing more than half of the length of Togo before flowing into the Gulf of Guinea. Together with its tributaries, it drains most of the south of the central mountain chain. The river is torrential and has an annual average intake of 99.6 m^3/s though it is 4.8 m^3/s in the dry season (January to May). The Oti River drains into the Volta River, which flows to the north-west.[3]

Electricity sector overview

Electricity generation in 2015 was approximately 1,360 GWh in Togo. Up to 86.5 per cent of the energy generated came from thermal and imported energy, 14 per cent came from hydropower plants, and a approximately 0.15 per cent came from solar energy.[13] Due to the unique energy agreement between Togo and Benin, data on total installed capacity can vary depending on the inclusion of Benin CEB capacities (Figure 1 and Table 1).

FIGURE 1

Installed capacities and CEB-guaranteed imports in Togo (MW)



Source: African Development Bank[11]
Note: Thermal and hydropower totals include guaranteed capacities from CEB (Benin) (Table 1).

The energy sector is supervised by the Ministry of Mines and Energy (MME), and its Direction Générale de l'Energie is specifically responsible for policy preparation and implementation in the electricity sector. The Autorité de Réglementation du Secteur Electricité is the electricity regulator; its duties include advising the MME on electric tariffs, among others. The Compagnie d'Energie Electrique du Togo (CEET) is the state-owned utility. While it does have generation capacity, it is mainly responsible for and has a monopoly on transmission and distribution.

The Communauté Électrique du Bénin (CEB) is a bi-national entity which was established in 1968 to provide generation and transmission for both Togo and Benin. The system was revised in 2003 to allow independent producers to participate in the market. In 2015, a bill was proposed to end the CEB monopoly on purchases of electricity from Togo.[7,8] An independent power producer which was established in Lome in 2010, Contour Global, operates a 100 MW tri-fired natural gas, diesel and heavy fuel-oil plant.[7] Details of the installed capacities for Togo, to include guaranteed capacities from CEB, can be found in Table 1.

Togo has two operational hydropower plants, with at least one large and eight small plants planned. The Nangbeto 65 MW plant is on the border with Benin, and through the energy agreement for the two countries, the generation and capacity is split between them.[7] The 147 MW plant, Adjarala, is still in the planning stages.[9]

The following table represents the main electricity tariffs in Togo.[13]

The national electrification rate is approximately 27 per cent, with 50 per cent in urban centres and 5 per cent in rural areas.[10]

While Togo has vast reserves of renewable energy (RE) sources, the majority remain untapped. This, combined with increasing electric demand, requires imports from neighbouring Ghana, Côte d'Ivoire and Nigeria to meet demand. Togo is also a member of the Economic Community of West African States (ECOWAS) energy framework and the West Africa Power Pool.[7]

TABLE 1

Installed, available and guaranteed capacities in Togo

Togo domestic plants	Type of plant	Installed capacity (MW)	Available capacity (MW)	Guaranteed capacity (MW)
Lomé A	Diesel	16	7	10
Lomé B	Diesel	14	14	—
Sokodé	Diesel	4	1.5	—
Contour Global	Gas / Diesel / HFO	100	100	90
Kpimé	Small Hydro	1.6	1.5	—
Kara	Diesel	16	4	—
Togo total	—	**151.6**	**128**	**100**

Benin CEB	Source	Installed capacity (MW)	Available capacity (MW)	Guaranteed capacity (MW)
Lomé TAGS	Diesel	50	40	40
Nangbeto	Hydro	65	65	30
CEB Imports	TCN (Nigeria)	—	200	200
	VRA (Ghana) CIE (Côte d'Ivoire)	—	102	102
Subtotal CEB to Togo (47%)		—	191	175
Togo total (including CEB to Togo)			**329**	**275**

Source: African Development Bank[11]

TABLE 2

Electricity tariffs in Togo

Group	Tariff (USD Dollars)
Up to 40 kWh	0.11
40-251 kWh	0.14

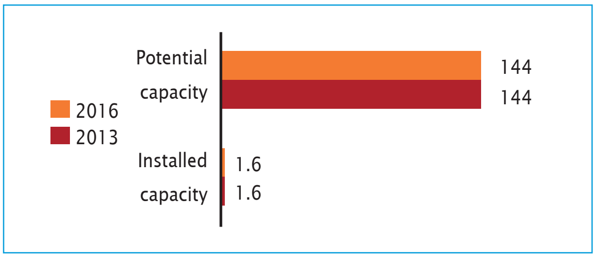
Source: CEET[6]

Small hydropower sector overview and potential

While there is no official definition of small hydropower (SHP) in Togo, for the purposes of this report, SHP will include installed capacities up to 10 MW. It should be noted that Togo is in the ECOWAS region, with many states and international documents using the ECOWAS definition of up to 30 WM. The installed capacity in the country is 1.6 MW. Currently, there is only one operating SHP plant in Kpimé (2x 0.78 MW with a generation capacity of 2.6 GWh/ year). SHP potential has been estimated at 144 MW (<10 MW) but, under the ECOWAS definition, the potential rises to 206 MW.[3,12] Older studies indicated that the total overall hydropower potential in Togo is 224 MW. This number is likely to change once new studies are undertaken (the Adjarala project potential has already been increased from 100 MW to 147 MW).[3,6]

FIGURE 2

SHP capacities 2013-2016 in Togo (MW)



Sources: CEET,[6] Ministere des Mines et de l'Energie,[12] *WSHPDR 2013*[15]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

As of 2013, CEET had identified eight economically feasible hydropower projects with a total potential capacity of more than 50 MW. Three sites will be proposed under the Scale Up Renewable Energy Program, with an implementation cost of US$75 million.[10]

TABLE 3

Potential hydropower sites in Togo

Site name	Potential capacity (MW)
Glei	2
Amou Oblo	2
Landa Pozanda*	4
Banga*	6
Tomegbe-Akloa	8
Kpessi	8
Titira	12
Danyi-Konda*	10

Source: Ministry of Economy and Finance[10]
Note: An asterisk (*) indicates planned SREP implementation.

Renewable energy policy

The Government, within its new Strategy for Boosting Growth and Promoting Employment (SCAPE) to develop and increase employment and electricity access, is implementing several measures related with RE. This strategy has goals to set up an institutional and legal framework helping to increase the use of RE, reduce the use of gas butane only for domestic use, cut taxes for exports involving RE related goods, build three solar plants (25 MW) and a wind plant (12 MW), a biomass plant (4 MW) and a waste management plant. The government is taking measures to develop the use of RE. For instance, the creation of a specific fund is foreseen, aiming to increase rural electrification in Togo. Current policies aim to develop the use of renewable energies to constitute up to 5 per cent of the total energy mix by the end of 2015. For that purpose, the government is shaping its agenda in order to achieve this target. Within this framework, the government is trying to accelerate, as stated before, the set up of RE plants (solar, wind, hydropower, and biomass). This includes the previously mentioned 30 hydropower potential sites (with more than 2 MW in sites like Oti or Sio).[4]

Barriers to small hydropower development

The Government is making efforts in order to promote the use of SHP. However, there are several barriers that need to be taken into account:[5]

- Lack of thorough and updated information regarding potential SHP sites;
- Lack of an accurate geographic information system survey;
- Dilapidation of transport and distribution lines;
- Ineffective exploitation of the MT/MB transformer;
- Lack of policies or agendas regarding renewable energies;
- Lack of a clear institutional and legal framework for the development of SHP;
- Lack of incentives for private investment, including import duty exemptions on RE equipment, feed-in tariffs (FITs) and power purchase agreements;
- Poor financial access for longer investment periods.

CHAPTER 2

Americas

Photo from Adobe Stock

2.1 Caribbean

Alberto Sánchez, GEF Small Grants Programme (SGP/GEF/UNDP); Michela Izzo, Guakía Ambiente

Introduction to the region

The Caribbean region is bordered by the United States to the north, Mexico and Central America to the west, South America to the south and the Atlantic Ocean to the east. The region includes 28 countries and territories. Ten of these will be covered in this report: Cuba, Dominica, Dominican Republic, Grenada, Guadeloupe, Haiti, Jamaica, Puerto Rico, Saint Vincent and the Grenadines, and Saint Lucia. The climate of the region can vary from arid (less than 400 mm of annual rainfall) to extremely humid (more than 7,000 mm); the highest humidity is seen in areas exposed to the trade winds. The Antilles shows a very complex topography, highly influenced by the active regional tectonics. For this reason, altimetry is significantly variable, ranging from less than −40 m to more than 3,000 m above sea level. The Greater Antilles (Cuba, Dominican Republic, Jamaica and Puerto Rico) is home to the largest rivers and hydropower potential. According to country-specific data, the region's total installed capacity is 17.1 GW, of which less than 5 per cent (844 MW) is from small hydropower (SHP) (Table 1). An overview of the countries in the Caribbean is presented in Table 1.

Country electricity access normally exceeds 90 per cent, with three countries (Guadeloupe, Saint Vincent and the Grenadines and Puerto Rico) providing their population with electricity. The only exception in the region is Haiti, where economic and institutional conditions are highly critical and only 30 per cent of the population has access to electricity, even then it is not continuously provided. Other countries where a significant percentage of the population (five per cent) lack electricity, especially in rural areas, are Dominica and the Dominican Republic. Despite attempts by both countries to improve the percentage of their respective populations covered by the electricity grids, significant challenges remain, especially for the most vulnerable and isolated communities.

The countries with the highest percentages of people without access to electricity are also the ones that show the biggest problems, such as poor efficiency and high losses.

The region is characterized by high domestic electricity rates, which exceed US$0.30/kWh in Dominica (US$0.36/kWh) and Saint Lucia (US$0.33/kWh). Cuba has the lowest rate (US$0.09/kWh) for consumption less than 100 kWh. The average value in the region is US$0.23/kWh.

All the countries in the region depend highly on imported fossil fuels for electric generation. In the majority of these countries, electricity (generation, transmission, distribution and commercialisation) is monopolistically managed, even though some changes have occurred

TABLE 1

Overview of countries in Caribbean (+ % change from 2013)

Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Cuba	11.4 (+1.3%)	23 (-2pp)	97 (0pp)	6,033 (-3.3%)	19,000 (+9.3 %)	62 (-3.1%)	127.3 (+59 %)
Dominica	0.07 (0%)	29 (-4 pp)	95 (0pp)	27 (0%)	103 (+15.7%)	6.6 (+3%)	25 (-22%)
Dominican Republic	9.4 (-5.0%)	24 (-7pp)	98 (-)	3,238 (-4.6%)	13,850 (-5.0%)	603 (+12%)	1,800 (+30%)
Grenada	0.1 (-5.4%)	64 (+3pp)	99.5 (-)	48.6 (-0.8%)	197 (-12.1%)	0 (0%)	0 (0%)
Guadeloupe	0.4 (-20%)	1 (0pp)	N/A	509 (-)	1,729 (-)	8.7 (-8.4%)	19 (-9.5%)
Haiti	10.4 (+4.1%)	43 (-5pp)	37.9 (-1 pp)	400 (+50%)	1,105 (+61%)	62 (-1.6%)	141 (-53%)
Jamaica	3.0 (+2.1%)	41 (-7pp)	98 (0pp)	902.8 (+3.5%)	4,112 (-18%)	30.1 (+36.8%)	136 (-11%)
Puerto Rico	3.6 (0%)	6 (+5pp)	100 (0pp)	5,839 (0%)	20,500 (-9.1%)	100 (0%)	56 (-58%)
St Vincent and the Grenadines	0.1 (0%)	53 (+2pp)	73 (-)	58.3 (+19 %)	140.7 (+1.2%)	5.6 (0%)	31 (+82%)
Saint Lucia	0.18 (0%)	91 (+19pp)	98 (0pp)	88.4 (+16 %)	379.4 (+11 %)	0.24 (0%)	N/A
Total	38.61 (-0.3%)	—	—	17,144 (+2%)	61,116 (+0.2%)	878.24 (+22%)	2,335.3 (+10%)

Sources: Various[1,2,3,4,5,6]

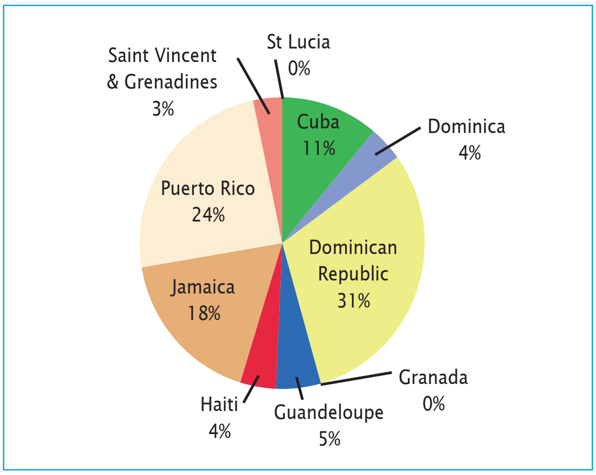
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

in recent years to bring about the entrance of other stakeholders into the market.

Puerto Rico, Jamaica and Cuba account for less than 70 per cent of the regional share of installed SHP (Figure 1). Between the *World Small Hydropower Development Report (WSHPDR) 2013* and *WSHPDR 2016*, installed SHP capacity has increased by almost 40 per cent from 124 MW to 171 MW, largely due to development in Dominican Republic (Figure 2).

FIGURE 1

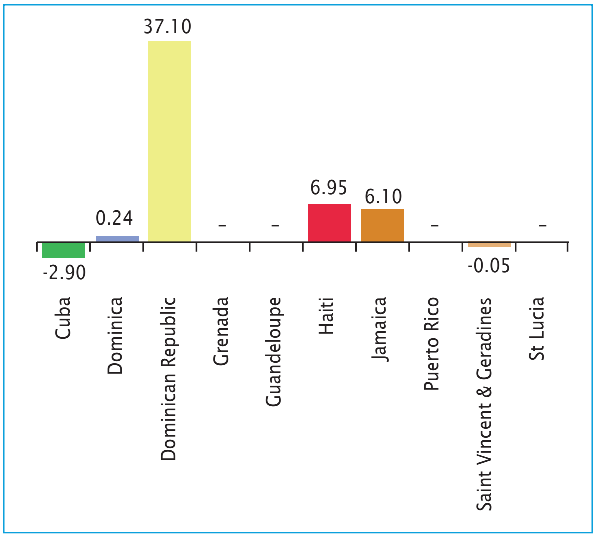
Share of regional installed capacity of SHP by country



Source: *WSHPDR 2016*[5]

FIGURE 2

Net change in SHP (MW) from 2013 to 2016 for the Caribbean



Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.

Small hydropower definition

Countries that have an official definition of SHP typically define it to be up to 10 MW installed capacity. Jamaica is an exception to this, defining SHP as 1 MW to 10 MW (Table 2).

TABLE 2

Classification of SHP in Caribbean

Country*	Small (MW)	Mini (MW)	Micro (kW)	Pico (kW)
Cuba	—	—	—	—
Dominica	Up to 10	—	—	—
Dominican Republic	Up to 10	—	—	—
Grenada	—	—	—	—
Guadeloupe	Up to 10	—	—	—
Haiti	1-10	—	100-1,000	Up to 100
Jamaica	1-10	—	—	—
Puerto Rico	Up to 10	—	—	—
Saint Vincent and the Grenadines	Up to 10	—	—	—
Saint Lucia	—	—	—	—

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*5

Regional SHP overview and renewable energy policy

All countries in the region are dealing with high costs and environmental problems linked to fossil fuels, with electric generation being one of the most impacted sectors.

For this reason, all the countries have begun to promote the use of renewable sources, which are specifically mentioned in National Energy Policies and Energy Action Plans. Some countries (Grenada, Guadeloupe, Saint Lucia, Jamaica, Puerto Rico, Dominican Republic) have established specific goals in terms of changes of national energy matrices: Guadeloupe has the highest target, since it is aiming for complete energy autonomy by 2050.

Among the countries, Haiti shows a poor legal and institutional framework with regard to the electricity sector. Most countries need to make more effort in obtaining ratification from their national parliaments, including mechanisms of support and specific regulations.

Among renewable energy sources, SHP systems constitute a feasible and attractive solution only in some of the countries in the region. In some cases, countries aim to continue to develop hydropower generation, also at a regional scale. One example is Dominica, which is focused on the development of common projects with Martinique and Guadeloupe.

Due to site-specific conditions, other countries are focused on other renewable sources, especially solar and geothermal.

TABLE 3

SHP up to 10 MW in Caribbean (+ % change from 2013)

Country	Potential (MW)	Planned (MW)	Installed capacity (MW)	Annual generation (GWh)
Cuba	135 (118%)	56	19 (-13%)	95 (-)
Dominica	6.64 (-)	—	6.64 (4%)	—
Dominican Republic	52.5 (-)	—	52.5 (+241%)	—
Grenada	7 (0%)	0	0 (0%)	0 (0%)
Guadeloupe	13.7 (-70%)	5	8.7 (0%)	27(+80%)
Haiti	20.9 (-58%)	—	6.95	—
Jamaica	59 (-6%)	10	30.1 (+25%)	153 (+0.7%)
Puerto Rico	44.9 (+0.2%)	—	41.8 (0%)	—
Saint Vincent and the Grenadines	7.4 (0%)	1.1	5.6 (-1%)	—
Saint Lucia	2.3 (+475 %)	0	0.24 (0%)	—
Total	**349.3 (+38%)**	**72.1**	**171.3 (+38%)**	—

Sources: *WSHPDR 2016*,[5] *WSHPDR 2013*[6]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. SHP installed capacity and potential for Jamaica includes the Maggoty plant (13.5 MW).

Considering that the region is exposed to extreme weather and climatic events, special care must be taken to develop projects based on climate change adaptation strategies.[7,8] Droughts, especially associated to El Niño episodes, have caused huge impacts during the recent years and are projected to severely affect the region in the future. For this reason, specific solutions must be implemented to reduce the risk of lack of production for SHP systems.

Another aspect that must be considered is the competing use of water sources, in an environment where they are increasingly limited. This will require appropriate planning.

Barriers to small hydropower development

The main barriers of SHP development in the region are as follows:

- Lack of feed-in tariffs and other incentive and/or supporting mechanisms;
- High project development costs;
- Difficulties in land acquisition;
- Environmental constraints;
- Excess of bureaucracy;
- Energy generation monopoly;
- Absence of appropriate protocols to facilitate contracts;
- Lack of appropriate data, which limits estimation and planning.

2.1.1 Cuba

Conrado Moreno, World Wind Energy Association

Key facts

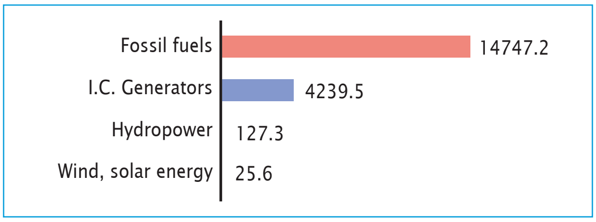
Population	11,379,111[1]
Area	110,860 km^2
Climate	Except in the mountains, the climate of Cuba is semitropical or temperate. The average minimum temperature is 21°C and the average maximum is 27°C. The trade winds and sea breezes make the coastal areas relatively cooler. Cuba has its rainy season from May to October. The eastern coast is often hit by hurricanes from August to October, resulting in great economic loss.[2]
Topography	Approximately a quarter of Cuba is mountainous with hills dotted across the whole island alternating with plains and three main mountain ranges: the Guamuhaya (or mountains of the Escambray), the Guaniguanico and the Maestra. The latter, located in the south-east, is the largest and home to Pico Real de Turquino, the country's highest peak at 2,005 m.[2]
Rain pattern	Cuba's rainy season is May to October. The mountain areas experience an average annual precipitation of more than 1,800 mm while most of the lowland regions range from 900 to 1,400 mm. The area around Guantánamo Bay in the south-east receives less than 650 mm of precipitation a year. Droughts are common.[2]
General dissipation of rivers and other water sources	The topography and climate of the island tend to result in short rivers with reduced flows. The longest river is the Cauto, at 249 km, flowing westward north of the Sierra Maestra. Other major rivers include the Sagua la Grande and the Toa.[2]

Electricity sector overview

In 2013, the most recent data available, total annual generation was approximately 19 TWh. Generation was dominated by fossil fuel based thermal power plants, including gas powered turbines and generation from industries, which contributed approximately 77 per cent. Grid connected internal combustion (IC) generators contributed 22 per cent while hydropower and other renewable sources contributed less than 1 per cent combined (Figure 1).[3]

FIGURE 1

Annual electricity generation in Cuba by source (GWh)



Source: ONEI[3]

In the same year, installed capacity totalled 6,033.1 MW with approximately 53 per cent from thermal power plants, including gas powered turbines, 38 per cent from diesel generators and 8 per cent from other thermal sources including generators operated by the Ministry of Basic Industry and Grupo Azucarero (AZCUBA). Hydropower installed capacity constituted just 1 per cent of the total (Figure 2).

Approximately 97 per cent of the population has access to the national electric grid. The remaining 2.7 per cent without electricity, approximately 70,000 families, are located in rural areas.[1] Total consumption rose by 27.3 per cent between 2000 and 2013 with the residential and industrial sectors consuming approximately 38 and 24 per cent, respectively. Losses amounted to approximately 14.6 per cent.[3]

The electricity sector in Cuba is completely publicly owned with the Electric Union, part of the Ministry of Energy and Mines, responsible for generation, transmission and distribution. The National Institute for Hydraulic Resources (INRH) is the regulatory authority for hydropower and water resources. Over the last decade, the electricity industry has undergone significant reforms beginning in 2005 with a new energy development strategy known as the Energy Revolution in Cuba. Distributed generation, electric grid rehabilitation, energy saving, energy education and the growing use of renewable energy sources are the key features of this strategy.[4] Development of the National Electric System has focused on decreasing the share of oil-based thermal power plants and an increase in the use of coal, liquid natural gas and biomass.[4,5]

More recently, the share of combined cycle and IC generators has risen, resulting in a move away from a concentrated system composed of large thermoelectric power plants towards a system of distributed generation. This in turn has reduced the consumption of fossil fuels with the energy efficiency of IC generators being higher than that of the large thermoelectric power plants. The reduced concentration of the country's generation capacity in large thermoelectric plants has also reduced the risks posed to the system from hurricane damage.

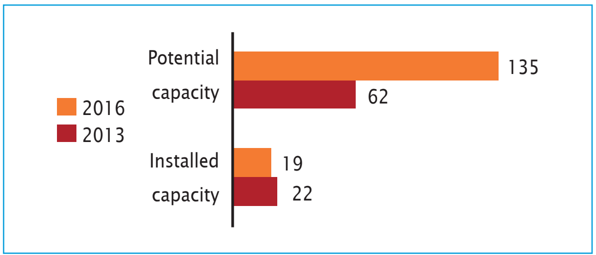
In 2005, Cuba undertook the Energy Revolution aimed at improving the country's energy efficiency. Alongside other measures, electricity tariffs were readjusted, and, as of 2013, were CUP 0.09 /kWh (US$0.004) for households consuming 0-100 kWh /month or less than 1,200 kWh /year. Each additional kilowatt per hour with a consumption of 101-150 kWh /month costs CUP 0.3 (US$0.013). Prices subsequently increase systemically for every additional 50 kWh per month up to CUP 1.3/ kWh (US$0.056) for a monthly consumption of 300 kWh.[16]

Small hydropower sector overview and potential

There is no official definition of small hydropower (SHP) in Cuba. However, this report assumes a definition of plants with an installed capacity of less than 10 MW. Current installed hydropower capacity is 62 MW, with 43 MW from the Hanabanilla plant and 19 MW of micro, mini and small hydropower. The identified technical potential of SHP is 135 MW.[6] This indicates that approximately 30 per cent of the country's SHP potential has been developed. In comparison with data from the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, installed capacity has decreased slightly while potential has more than doubled (Figure 2).[7]

FIGURE 2

SHP capacities 2013-2016 in Cuba (MW)



Sources: CIER,[6] *WSHPDR 2013*[7]
Note: The comparison is between data from WSHPDR 2013 and WSHPDR 2016.

As of 2015 there were 179 SHP plants (8 small hydro, 35 mini hydro and 137 micro hydro) with an average annual generation of 95 GWh. A total of 147 installations are in operation, while 24 are out of service and require refurbishment. Of the total 62 MW, 4.7 MW (149 plants) are not connected to the grid and provide electricity to 35,000 inhabitants, 78 health institutions, 138 schools and 188 economic entities.[14]

An estimated total SHP potential of 135 MW has been identified with the addition of 230 installations including 13.7 MW in channels for transporting water between dams. The estimated annual energy generation is approximately 443 GWh.[4]

Beginning with the conversion of existing dams and water channels, a programme has been initiated by the government for the construction of 74 SHP plants with a combined capacity of more than 56 MW and an estimated annual generation of 274 GWh.[8]

Renewable energy policy

The two key challenges for the Cuban electricity sector are the high cost of generation, approximately CUP 4.67 (US$0.21)/kWh, and heavy dependence on oil imports. For these reasons, in July 2014, the Council of Ministers and the Cuban Parliament approved a policy for developing the country's renewable energy sources with the aim of diversifying the energy mix considering the use of all possible renewable energy sources.

TABLE 1

SHP sites in Cuba (1 MW to 10 MW)

Site name	Location	Installed capacity (MW)	Generation (GWh)
Carlos Manuel de Cespedes	Contramaestre	1.5	10.7
Chamba	Chamba, Ciego de Avila	1.1	3.2
Corojo	Corojo	2.0	13.0
Guaso	Guantánamo	1.8	12.6
Nuevo Mundo	Moa	2.0	16.0
San Blas	San Blas, Cienfuegos	1.0	7.0
Yara	Yara, Granma	2.6	18.2
Zaza	Zaza, Santi Spiritus	2.7	13.0

Source: CUBAENERGIA and OLADE[15]

The main objectives of the policy are:

- To reduce the dependence on fossil fuels and thus increase energy independence;
- To decrease the high consumer cost of energy stemming from both the cost of fuel and the low efficiency of the electricity system;

- To contribute to environmental sustainability;
- To introduce a new law governing foreign investment.

While the new law governing foreign investment (Law 118-2014, replacing Law 77-1995) does not include specific legislation for renewable energy sources, the Government, through several directive documents, has recognized the decisive role that renewable energy sources have to play in the future development of the country. The foundation is formed in the Environmental Law (Law 81-1997), and has been subsequently added to over the past two decades. With regard to hydropower, Resolution 114-1990 gives the authority to the National Institute of Hydraulic Resources (INRH) to approve the entities that are authorized to construct any project related to water, to include foreign entities.[15] A key principle of foreign investment is that it contributes to a change in the energy mix through the development of solar power, wind power, hydropower, biogas and agricultural and industrial residuals such as sugarcane biomass. More recently, with the Cuban Program to Combat Climate Change (el Programa Cubano de Enfrentamiento al Cambio Climático) and The 2012 National Water Policy (La Política Nacional del Agua 2012), efficient and responsible management and utilization of water resources has become a national priority for the country. Thus, the government is open to investment from foreign enterprises in renewable energy projects, either by means of joint ventures with Cuban enterprises or totally foreign investment.[3,6,9,10,11]

Barriers to small hydropower development

The barriers that have limited the use of SHP in Cuba are the same that have limited the development of the other renewable energy sources. These technical, social, institutional, economic and financial, and regulatory barriers include:

- A lack of integral policies or specific legislation to govern the development of energy;
- A lack of development projects;
- Limited financial resources;
- Lack of specialists in technical and maintenance service;
- Limited ability of the national industry to ensure equipment, components and spare parts;
- Low usage of the existent production capacities;
- Limited scientific and technological capacity for the water sector;
- Limited capacity to carry out studies of feasibility;
- Insufficient maintenance of existent facilities.[12,13]

2.1.2 Dominica

Sven Homscheid

Key facts

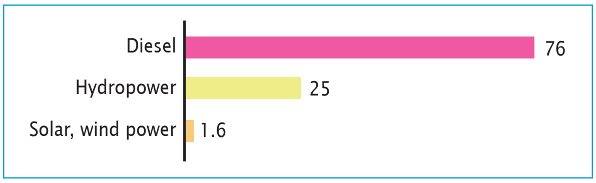
Population	72,341 [1]
Area	751 km²
Climate	Dominica has a tropical wet climate with warm temperatures and heavy rainfall. Excessive heat and humidity are tempered by the north-east trade winds, which may develop into hurricanes. The steep interior slopes also alter temperatures and winds. Temperature ranges are slight. Average daytime temperatures generally vary from 26°C in January to 32°C in June.[2]
Topography	Dominica is the largest and most northerly of the Windward Islands. The country has lush green vegetation of tropical flora on steep slopes in dense forests and one of the most rugged landscapes in the Caribbean. The highest mountain, Mount Diablotins, is 1,447 m high.[2]
Rain pattern	Strong rains characterize the weather, with a rainy season from July to December and a dry season from January to June. Rainfall depth ranges from about 2,000 mm at sea level to more than 8,000 mm in the mountain ranges.[2]
General dissipation of rivers and other water sources	Dominica is water-rich with swift-flowing highland streams and has 365 rivers as well as many waterfalls. The major rivers are the Layou, Roseau and Toulaman.[2]

Electricity sector overview

According to the Dominica Electricity Services (DOMLEC) Annual Report of 2014, the installed electricity generation capacity in Dominica was 27.16 MW, of which 420 kW are privately owned renewable energy (RE) generators, 6.64 MW are from utility-owned small hydropower (SHP) and 20.1 MW are from utility-owned diesel generators (Figure 1). In 2014, total net electricity generation was estimated to be 102.6 million kWh, with peak demand at 16.972 MW.[3] The country's electrification rate is above 95 per cent.[5]

FIGURE 1

Electricity generation in Dominica (GWh)



Source: DOMLEC[3]
Note: Data from 2014.

Due to the widespread distribution of the population in the supply area and therefore lengthy transmission lines, energy supply is very expensive. This results in an electricity rate of more than US$0.36/kWh. Dominica Electricity Services Limited (DOMLEC) is the country's sole vertically integrated electric utility. Although there are smaller independent power producers, such as the 275 kW Rosalie wind turbine and a 50 kW photovoltaic plant, DOMLEC has a monopoly on transmission and distribution of electricity.

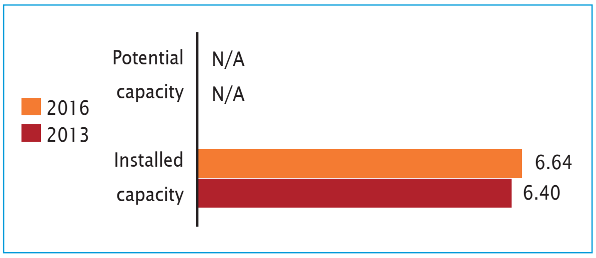
DOMLEC is 20 per cent government-owned, with the other 80 per cent owned by private investors and other shareholders. Since June 2007, the Independent Regulatory Commission has acted as regulatory body. However, it has had limited efficiency regarding the promotion of renewable energy. The electricity market is liberalized and anyone is free to apply for a generation, transmission, distribution or sales license for electricity. Despite this, besides DOMLEC's generation and transmission, distribution, and sales licenses, to date only a few licenses have been issued to independent power producers for a total of 417 kW from renewable energy. Effective as of 2014, two new licenses, valid for 25 years, were issued to DOMLEC: a non-exclusive generation license and an exclusive transmission, distribution and supply license. Dominica has been a member of the Petro Caribe Union since 2005.

Small hydropower sector overview and potential

The definition of SHP in Dominica is up to 10 MW. The installed capacity of SHP is 6.64 MW. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 4 per cent.

FIGURE 2

SHP capacities 2013-2016 in Dominica (MW)



Sources: *WSHPDR 2013*,[6] DOMLEC[3]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Hydropower development in Dominica for the generation of electricity started during the British colonial period in 1951, with the installation of two 320 kW Pelton units in the Trafalgar powerhouse. This was extended in 1959 with a third Pelton unit of the same capacity. Old Trafalgar was replaced by the New Trafalgar hydropower station in 1991, which houses two Pelton turbines of 1,761 kW each. The current hydropower infrastructure in Dominica belongs entirely to DOMLEC and consists of 6.64 MW in the three power stations: Laudat, New Trafalgar and Padu, all in the Roseau River watershed.

The many waterfalls on the island suggest a large hydropower potential in Dominica. The Caribbean Renewable Energy Development Programme (CREDP-GIZ) has proposed and studied a hydropower project, Newtown HPP, at an existing bulk water pipeline that is owned by the water utility Dominica Water and Sewerage Corporation (DOWASCO). The pipeline takes water from the Padu tailrace and transports up to 320 l/s to the shores in Roseau. It was proven to be technically and financially feasible to install a 200 kW turbine at the end of the pipeline to generate electricity to be fed into the public grid. Due to a pending positive investment decision by the water utility, the project has not yet been implemented. CREDP-GIZ conducted a qualitative hydropower potential assessment in 2012 and has identified the Roseau River, the White River, the Layou River, the Belfast River and the Rosalie River as most promising for hydropower use.[4] The study did not quantify the potential but rather made relative statements.

Renewable energy policy

In 2011, a National Energy Policy and a Sustainable Energy Plan were developed. In a section about hydropower, the National Energy Policy states:

The policy for hydropower development includes:

- Continuing the assessment of hydropower resources by coordinating the efforts of the Ministry of Agriculture and Forestry, DOMLEC and DOWASCO
- Implementing, where feasible, new hydropower projects
- Developing capacity for analysing data on hydro projects by working with other countries and territories in the region, especially Martinique and Guadeloupe [5]

However, as of mid 2015, neither the energy policy nor the action plan has been ratified by the Dominican Parliament. Besides, the Independent Regulatory Commission (IRC) has not yet set out standard procedures for the development of new projects. No mechanism or instrument for the support of RE development has been developed. Project development happens on an individual basis. No feed-in tariff (FITs) has been set for RE generation and no other incentivizing mechanism has been implemented. These factors complicate the development of renewable energy in the country.

For the Newtown hydropower project, DOMLEC offered a tariff of about US$0.078, possibly too low for the implementation of economic hydropower projects. Considering retail prices of US$0.36/kWh and more, this low tariff may not be justified, proof of which is pending. In addition, hydropower generation has to compete against diesel fuel costs, which as of the end of 2015 were very low when compared to the 2008 price spike. Due to the increasing use of rivers for touristic purposes and the development of eco-tourism in Dominica, new hydropower projects will also compete with tourism. The Government is very conscious of maintaining environmental standards when developing infrastructure projects, as eco-tourism is one of the major sources of income. Other related studies and mitigation measures may also increase project costs.

Barriers to small hydropower development

The main barriers to SHP development in Dominica are as follows:

- The prospective development of geothermal resources has shifted national interest away from other renewable energy sources, including SHP.
- Developments in eco-tourism may be perceived as contradictory to hydropower development.
- The lack of FITs or other incentive mechanisms for small-scale hydropower is not attractive for potential developers. The tariff currently offered by DOMLEC may be too low to attract investors in SHP development.
- Delay in ratification of the National Energy Policy and the National Sustainable Energy Action Plan.
- Project development costs in Dominica may be too high to justify feasible hydropower projects.
- Land acquisition for hydropower projects is difficult as many properties are privately owned and difficult to obtain.

2.1.3 Dominican Republic

Alberto Sánchez, GEF Small Grants Programme; Michela Izzo; Guakia Ambiente

Key facts

Population	9,445,281 [1]
Area	48,311 km[2]
Climate	The climate is tropical humid, with high regional diversity, ranging from arid to extremely humid. This is due to the physical geography of the country, which is characterized by mountain chains that 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 in the Enriquillo Lake, south-western region.[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 to 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 m.[2]
Rain pattern	The orientation of the mountain chains can cause variations 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-east of the country with annual rainfalls of up to 3,000 mm, while the driest areas can be found in the Enriquillo Valley in the south-west, with less than 450 mm per year.[2]
General dissipation of rivers and other water sources	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 River but only 68 km of it is located in the Dominican Republic. Lake Enriquillo is the largest lake not only in the Dominican Republic but also the entire West Indies.[2]

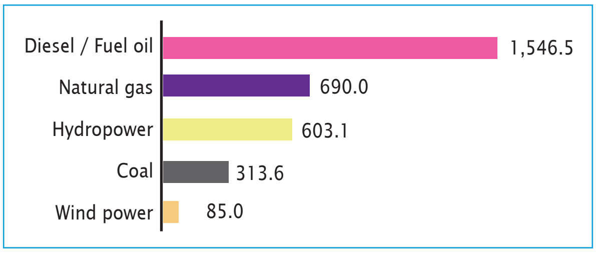
Electricity sector overview

In 2014, the total installed capacity stood at 3,238.2 MW. Approximately 47.8 per cent came from diesel or fuel oil based power plants, 21.3 per cent from natural gas and 9.7 per cent from coal. Renewable sources contributed 21.2 per cent of the total, with hydropower plants providing 18.6 per cent and wind plants 2.6 per cent (Figure 1).[3]

Total generation in 2014 amounted to 13,849.5 GWh. Diesel and fuel oil contributed approximately 40.4 per cent, natural gas 30.7 per cent, coal 15.3 per cent, hydropower 12.9 per cent and wind power 0.7 per cent.[3]

FIGURE 1

Installed capacity in the Dominican Republic by source (MW)



Source: SENI[3]

One important structural problem in the country is the provision of electricity. The Dominican electricity system is characterized by low stability, reduced quality, insufficient supply and high losses that can reach 40 per cent of the total energy.[4] Thus, despite the installed capacity exceeding the national demand of 1,800 MW, the average generative capacity is below 1,500 MW. In this context, more than 5 per cent of the population does not have access to electrical services. Rural areas receive the worst impact in terms of deficient provision. However, there is no accurate data for the rate of rural electrification.[5] In 2011, the Dominican Republic was listed 132nd among the 139 countries analysed by the World Economic Forum for quality of electricity supply.[4]

The country is highly dependent on fuel imports since it lacks any significant sources of fossil fuels. Nonetheless, the Dominican Republic has one of the highest GDP growth rates in the region, which has resulted in a rapid increase in energy demand and consumption. According to national projections, net energy demand will continue to increase at 2.3 to 3 per cent per year until 2030, with a total increase of 58 to 80 per cent in 2030 as compared to in 2010. Electricity demand is expected to grow at 2.5 to 3 per cent annually for residential users and at 3.3 to 4.7 per cent for the commercial, public and service sectors.[21]

The Dominican electrical system is state-owned. However, generation, transmission, distribution and commercialization of energy are carried out by private enterprises. The Coordinator of the National Interconnected System (OC-SENI) is the state agency responsible for coordinating the transmission, generation and distribution within the National Interconnected Electric System (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. The Dominican Corporation of State Electrical Enterprises (CDEEE) is responsible for the management of electrical enterprises and implementation of state programmes for rural and urban electrification, guaranteeing synergy, effectiveness, profitability and sustainability.

The Dominican Republic has one of the highest electricity rates in the Caribbean and Central America, with final customers having to pay more than US$0.20/kWh. This is more than three times the US$0.06/kWh that people pay in the 16 off-grid community-owned, Small Grants Programme, hydropower plants outlined below.[9]

Two different types of government subsidies exist. First, there is the Bonoluz programme, which implies a direct subsidy of up to 100 kWh to 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. Finally, these customers also receive a subsidy for the fixed charge. The second type of subsidy is the Fund for the Stabilization of the Electric Tariff (FETE), which is based on tariff differences and tries to compensate for the high cost of fuels.

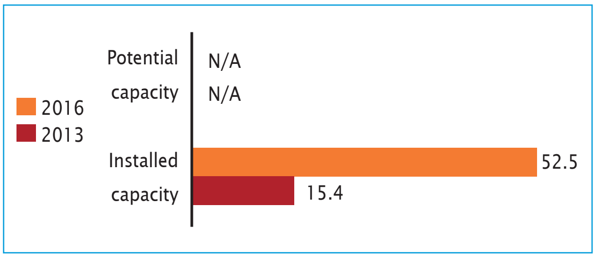
Small hydropower sector overview and potential

In the Dominican Republic, small hydropower (SHP) is classified as plants with a total capacity of no more than 10 MW.[10] Installed capacity is approximately 52.5 MW, though no accurate data on SHP potential exists.[10,11] In comparison to data from the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, installed capacity has more than tripled (Figure 2).[12]

Fourteen state-owned SHP plants are operational as of 2015 with a combined installed capacity of 51.4 MW. Half of the plants have a capacity of less than 2.5 MW. Twelve of the plants are located in the Cordillera Central, the main mountain chain of the country, and contribute 83.9 per cent of the installed capacity. The most developed location is the Yaque del Sur basin with 5 plants contributing 46.5 per cent of the installed capacity.[10] In addition, there are 36 operational micro-hydropower systems, ranging from 0.5 kW to 150 kW, with a combined installed capacity of 1.1 MW. The total hydropower installed capacity is 603 MW. It is the Dominican Republic's most important energy source after fossil fuels, with SHP contributing 8.7 per cent of the total energy produced by the country.

FIGURE 2

SHP capacities 2013-2016 in the Dominican Republic (MW)



Sources: EGEHYD,[10] Sánchez et al.,[11] *WSHPDR 2013*[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

A comprehensive study on hydropower potential in the Dominican Republic has not been carried out. Such a study is necessary for further SHP development. Due to the climate and topography of the country, considerable potential can be expected, in particular on the Cordillera Central, the largest massif in the country.

In the last ten years, following approval of the Renewable Energy Incentive Law (Law 57-07), there have been considerable developments in community micro-hydropower systems. With the leadership of the Global Environmental Facility (GEF) Small Grants Programme and Guakía Ambiente, a Dominican NGO, the 36 micro-hydropower plants mentioned above were successfully established as community-owned systems.[13,14,15] Together they have provided a continuous energy service to more than 3,800 families, schools, rural health and community centres, micro enterprises and communication centres in rural isolated areas.[15] In addition, CO_2 has been reduced by more than 24,000 tons per year and over 70 km^2 of forest has been conserved.[15] One of the reasons behind the success of these projects is the model's emphasis on community autonomy with regard to the systems management, making the community responsible for both the technical and financial administration.[15]

As of 2015, a further 12 systems are under construction, with capacities of 10-100 kW. A number of additional communities have been requesting similar projects.[15] With the number of organisations participating in these projects growing significantly year on year, the duration of the implementation phase has also been considerably reduced. If a comprehensive study were to be carried out on micro-hydropower potential at a national scale, GEF estimates that more than 100 similar projects could be developed.[15]

In addition, the success of the community-owned model has helped increase the number of potential financial sources. These now include: the Dominican Government, the Suburban and Rural Electrification Unit and EGEHID, local governments, national NGOs, the United Nations, the European Union, the Inter-American Foundation and the private sector.[12,16,17,18] The participation of the private sector provides a significant focus on the importance of giving financial sustainability to the initiatives and promoting local enterprises that can boost rural economies. In total, more than US$15 million has been invested in mini and micro-hydropower systems since 2010.[13,14]

Renewable energy policy

The Dominican policy on renewable energy is defined by the Incentive to the Development of Renewable Energy Sources (Law 57-07) and the corresponding regulations (No. 10469 of 30 May 2008). The law introduced a target of 20 per cent of national energy consumption produced from renewable energy sources by 2020, with the aim of reducing the dependence on imported oil and other liquid fuels. This policy will be implemented alongside improvements to the national electric system to both reduce energy losses and increase the percentage of users' payments.

At a national scale, renewable energy initiatives have been growing during the last five years. Wind projects have been assuming a significant role: at present, 85.5 MW come from wind plants at a large scale. Three other projects, for a total installed capacity of 130 MW, are under construction.

Legislation on small hydropower

Law 57-07 applies to mini, micro and SHP up to 5 MW, as well as other RE sources. An exemption from all import taxes is granted on imports of equipment, machinery and necessary accessories for the production of energy from renewable sources (Paragraph II). Income tax exemption for a period of 10 years from the beginning of its operations, and with maximum force until 2020, is also granted. According to Article 11, a reduction to a fixed five per cent on the tax over foreign financed interest payments is also foreseen (modifying Art. 306 of the Dominican Tax Code, for the beneficiaries of this law).[20]

The Regulation for the application of the Law 57-07 establishes incentives and feed-in tariffs (FITs) for renewable energy sources, according to the specific type. However, these do not apply to hydropower, small or otherwise (Table 1).[19]

TABLE 1

FITs in Dominican Republic for renewable energy sources

Type	Tariff (US$/kWh)
Wind connected to SENI:	0.1252
Wind from auto-production to be sold to SENI	0.0487
Electricity from biomass connected to SENI	0.116
Electricity from biomass from auto-production to be sold to SENI	0.0487
Electricity from Solid Urban Waste to be sold to SENI	0.085
Photovoltaic connected to national grid (power > 25 kW)	0.535
Photovoltaic from auto-generation to SENI (power > 25 kW)	0.1

Source: Government of the Dominican Republic[19]

Barriers to small hydropower development

One of the main barriers to community-owned micro-hydropower generation is gaining representation at the national level. Communities must strengthen inter-community networks to allow for the interchange of experiences and knowledge, provide mutual support and reduce vulnerabilities. Decentralization in decision making is another crucial challenge. In this context, it is important to strengthen community-based organizations, so that they can receive funds without intermediaries. Another barrier is the need to minimize bureaucracy and reduce the time needed to complete administrative procedures, especially when community initiatives are developed. A further challenge is the effects of climate change and the degradation of the main watersheds in the country. Both factors have significant impacts in terms of water availability negatively affecting electricity generation. Finally, the present shortage of data is a significant barrier and a comprehensive study on mini and micro hydro potential of the Dominican Republic is crucial to future SHP development in the country.

2.1.4 Grenada

Sven Homscheid

Key facts

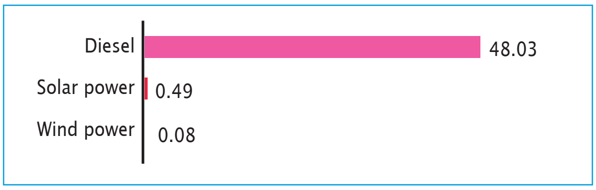
Population	106,349[1]
Area	345 km^2, including the islands of Grenada, Carriacou, and Petite Martinique.
Climate	Grenada has a tropical climate, with temperatures around 26°C and little variation over the year. Daytime temperatures vary between 26°C and 32°C while at night temperatures drop to between 19°C and 24°C.[2]
Topography	The terrain is made up of lush green vegetation on steep slopes of volcanic origin. Its highest mountain is Mount Saint Catherine, at a height of 840 m. Average elevation ranges from 300 to 600 m above sea level.[2]
Rain pattern	Average precipitation is 1,500 mm, peaking at 4,000 mm. The greatest monthly totals are recorded throughout Grenada from June through November, the months when tropical storms and hurricanes are most likely to occur.[2]
General dissipation of rivers and other water sources	The majority of the rivers are located in the centre and north of the island. The upper reaches of some rivers can overflow and cause flooding, while the lower reaches of the rivers can be slow. The largest lake, which was formed in a volcanic crater, is Grand Etang.[2]

Electricity sector overview

Grenada has an electrification rate of around 99.5 per cent. By the end of 2014, the country's installed capacity was 48.59 MW, comprising diesel at 48.03 MW (98.84 per cent), solar 0.49 MW (1 per cent), wind 0.077 MW (0.16 per cent) (Figure 1). Peak electricity demand was 30.2 MW and the annual electricity generation was 196.7 GWh.[3]

FIGURE 1

Installed capacity in Grenada (MW)



Source: Grenada services Ltd.[3]

Other renewable sources are currently not contributing to the energy mix. There are plans for Carriacou to build a high penetration diesel and wind hybrid system to power the island, and a first tendering resulted in exorbitant prices and stalling of the project.

Transmission voltage level is 33 kV, while distribution voltage level is 11 kV, the transmission losses range at 7.6 per cent. The grid availability is fairly good with only a few shut downs, mainly caused by severe weather events. The diesel plant availability is about 89 per cent.[3]

The sole electricity utility, Grenada Electricity Services Limited (GRENLEC), is 21 per cent government-owned, 50 per cent owned by a private company from the US and 29 per cent owned by other private entities, including staff.[1] GRENLEC is a vertically integrated monopolistic company with an operation license until 2073. The Electricity Supply Act of 1994 does not allow any other entity but GRENLEC to generate, distribute or sell electricity in Grenada, while GRENLEC may authorize third party electricity generation.[6]

Besides the GRENLEC shares held by private entities, the private sector participates in the market through privately owned solar PV systems that are grid connected under either a net-metering or a net-billing agreement with the utility. The utility company allows on a case-by-case basis renewable energy generators up to 100 kW to sell their electricity to the grid.

There is no de facto sector regulator at present, although the law foresees a regulatory commission. An electricity sector reform process was started and new legislation and regulation is being prepared that may install a regional sector regulator. In March 2011 the Government of Grenada passed a National Energy Policy with the aim of providing 20 per cent of its electricity generation from renewable energy sources by 2020.[7]

The current electricity tariff is based on the 1994 Electricity Supply Act and foresees a base rate and a fuel rate to pass through diesel cost from electricity generation. The base rate level in 2014 was approximately US$0.15/kWh and the fuel surcharge between US$0.13 and US$0.24/kWh.

The fuel surcharge is calculated monthly based on a running three-month average basis. The base rate was last modified in 2014 based on the consumer price index.[3] Electricity tariffs are structured in different classes for domestic, commercial, industrial and street light (government) customers. Theoretically, a fifth class for NGOs exists but is not applied.

Owners of renewable energy based generators selling electricity to GRENLEC are remunerated either at a fixed rate of US$0.167/kWh or at a variable rate equal to the average fuel price per kWh of the previous year. Both arrangements are valid for a 10-year period. This arrangement has caused the installation of new private owned renewable generators to nearly stop entirely as it is almost impossible to achieve economic viability of PV projects under 100 kW size with the offered remuneration.

The 1994 Energy Supply Act foresees a regulatory commission, but this was never established. De facto, the sector is not regulated, whereby the Energy Supply Act, the respective regulations and the contracts define the regulatory regime in such strict boundaries that regulation is not possible.

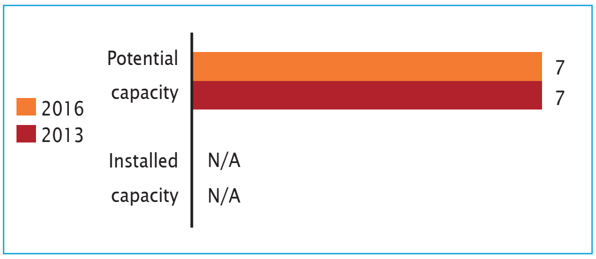
The reform of the electricity legislation that is currently underway seeks to introduce a new regulatory regime with the aim to shift electricity generation towards renewable energy use and lower electricity rates for consumers.

Small hydropower sector overview and potential

While there is no local definition of small hydropower (SHP), this report assumes the definition of installed capacity up to 10 MW. Installed capacity of SHP in Grenada is 0 MW, the potential capacity is approximately 7 MW.[8] Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed and potential capacity has not changed (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Grenada (in MW)



Source: *WSHPDR 2013*[8]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Currently, there is no official definition for SHP in the country. However, this may not be of significance as there is no SHP potential for a single plant of more than 10 MW in Grenada. In the past, sugar cane estates used hydro wheels to operate mills, but none of these early hydropower stations are in operation today. Several studies have been undertaken to assess the potential hydropower of projects. A hydropower potential analysis done 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 the 720 kW Birchgrove and the 380 kW Belvidere hydropower projects. To date, none of the identified sites have been developed. Hydropower is therefore not used in Grenada.[8]

In 2011 the Government of Grenada passed a National Energy Policy, which encourages the use of renewable energy resources with particular focus on geothermal energy. However, the policy does not explicitly mention hydropower. There are no support mechanisms for hydropower development in the country. Thus, hydropower generation falls under GRENLEC's voluntary interconnection policy for renewable energy generation.

There are no special financing mechanisms in place for renewable energy equipment or projects in Grenada. The Caribbean Development Bank has recently set up a renewable energy and energy efficiency section that seeks to foster increased lending in renewable energy and energy efficiency projects.

Several international donor projects, for example, the GIZ and World Bank, can be approached for assistance to identify suitable project financing for larger projects.

Renewable energy policy

The National Energy Policy, dated November 2011, states the country's goal to generate 20 per cent of its energy supply from renewable sources for domestic energy use (electricity and transport). The policy further elevates the overall importance of renewable energy for the country's development path. Special reference is made to geothermal resources. However, hydropower is not particularly mentioned.

The national power company, GRENLEC, allowed private owners of small solar PV systems to connect their systems to the public grid on a net-metering agreement up to a total of 300 kW cumulative installed PV capacities. This cap was reached in 2014. Since June 2015, GRENLEC has changed the modus to net billing with a remuneration rate of US$0.167/kWh for electricity sold to the grid. This is the current feed-in tariff (FIT) that GRENLEC grants, which is oriented at the avoided fuel cost, but it is not regulated by an official entity and may be changed any time.

Barriers to small hydropower development

The national focus is on geothermal and solar resources, with a secondary focus on wind power. Hydropower does not play any role in the country's energy supply planning. Therefore, no incentives or other special framework conditions for hydropower development were created. However, SHP of up to 100 kW capacity falls under GRENLEC's distributed renewable energy policy and may be eligible for the FIT. Larger plants require separate agreements with the power company.

The country's hydropower potential is poorly investigated and was estimated to be up to 7 MW, with the largest plant being of about 720 kW size. This potential does not attract investors, particularly as the processes and procedures for hydropower development are not clearly defined and thus pose a special risk.

Legally, the power utility in Grenada is monopolistic for electricity generation and selling. This framework condition does not favour safe investment in expensive technologies such as for hydropower projects.

The electricity sector reform process that was started in 2015 may change the rules of the process and open the market for independent power producers. Yet there will not be any special rules or regulations for hydropower development as the main focus will be on geothermal, solar and wind power.

2.1.5 Guandeloupe

Fanni Bodri and Gonzalo Marzal Lopez, International Center on Small Hydro Power

Key facts

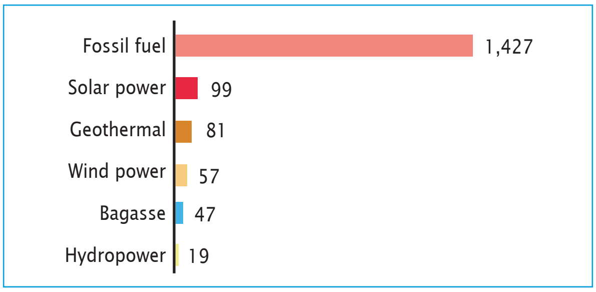
Population	403,750 [1]
Area	1,628 km^2
Climate	The climate is characterized by two distinct seasons, with the rainy season occurring between June and November and the dry season between December and May. Hurricanes may occur any time from June through November, and most likely during September. However, climate change may alter long-standing patterns. Average air temperatures range from 22°C to 30°C in coastal areas and from 19°C to 27°C in inland areas. Coastal water temperatures are generally between 20°C and 23°C.[2]
Topography	Located at the southernmost of the Leeward Islands in the eastern Caribbean Sea, Guadeloupe comprises the larger islands of Basse-Terre and Grande-Terre and three smaller islands. The two larger islands are separated by a narrow sea channel. Basse-Terre has a rough volcanic relief with the highest point at Soufriere volcano (1,467 m). Grande Terre features rolling hills and flat plains.[3]
Rain pattern	Total annual precipitation averages 1,814 mm. On average, September is the wettest and February is the driest.[4]
General dissipation of rivers and other water sources	Basse-Terre is the main source of water and most of its rivers take their rise in the island's national park.[5] A few of the rivers in Basse-Terre are the Lézarde Rivière, Moustique Rivière, Rose Rivière and Petite Rivière à Goyaves. Grande-Terre has Canal Perrin and Rivière des Coudes. Rivière Salée or the Salt River is the ocean canal separating Grande Terre and Basse-Terre. To supply the dryer regions of Grande-Terre and some of the nearby small islands, water storage capacities must be created and new resources tapped.[6]

Electricity sector overview

In 2013, the electricity generation was 1,729 GWh.[8] The majority (82.5 per cent) of generation came from fossil fuels, namely diesel and coal, while the remainder was from renewable sources: 5.7 per cent from solar energy, 4.1 per cent from geothermal energy, 3.3 per cent from wind power, and 1.1 per cent from hydropower (Figure 1). Electricity consumption was 1,508 GWh in 2013.[7]

FIGURE 1

Electricity generation by source in Guadeloupe (GWh)

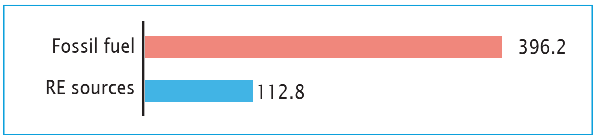


Source: Guadeloupe Energie[8]

The installed capacity in Guadeloupe was up to 509 MW in 2013, with 396.2 MW from fossil energy and 112.8 MW from renewable energies (Figure 2).[8] The utility rates in Guadeloupe are approximately US$0.18/kWh, below the Caribbean regional average of US$0.33. The reason for these low rates is that French electricity regulations equalize prices across the mainland and the overseas territories.[9]

FIGURE 2

Installed electricity capacity in Guadeloupe (MW)



Source: Guadeloupe Energie[8]

Regarding the electricity grid, an Eastern Caribbean Gas pipeline project has been proposed to stretch 970 km from Tobago to Saint Lucia, Dominica, Martinique and Guadeloupe. The idea to build a pipeline to import 100 MW of geothermal power from Dominica has also been proposed.[10]

Small hydropower sector overview and potential

Small hydropower (SHP), operating in numerous sites in Guadeloupe, has an installed capacity of 8.7 MW and produced 27 GWh electricity in 2014, as compared to 15

GWh in 2010.[13,11] The existing hydro-activity is centred in Basse-Terre, due to favourable altitude and available resources. Only the sites of Letaye and Gaschet are located in Grande-Terre.[11] The sites are operated by EDF (Electricite de France) or the FHA (Force Hydraulique Antillaise). The FHA has been present in the field of renewable energy since 1999 and has established 13 SHP plants.[14] The individual installed capacities of the SHP plants in Guadeloupe range from 0.1 MW to 3.5 MW (Table 1).

TABLE 1

Installed SHP capacity in Guadeloupe

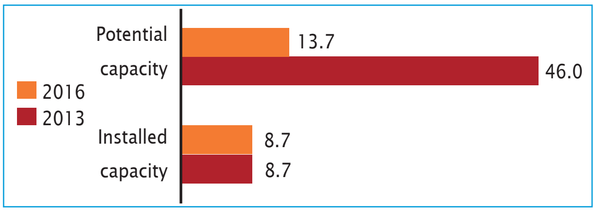
Site name	Installation date	Installed capacity (MW)
Carbet	1993	3.5
Bananier amont	1994	1.2
Bananier aval	1994	1.8
Partiteur 1 & 2	1995	0.5
Gaschet	2002	0.2
Letaye	2002	0.2
Bellevue	2002	0.1
Clairefontaine	2002	0.2
Saint Sauveur	2003	0.07
Schoeler	2004	0.07
Le Bouchu	2004	0.2
Dole	2004	0.2
Valeau	2006	0.2
Bovis	2008	0.25

Source: Guadeloupe Energie [11]
Note: Data includes EDF and Force Hydraulique Antillaise sites, as of 2010.

The regional Government has carried out feasibility studies of two sites that are planned to become operational soon: Riviere du Gailon of 1.5 MW and Capesterre of 3.5 MW.[16] Therefore, the country's SHP potential is at least 13.7 MW. However, total SHP potential is currently unavailable (Figure 3). Total hydropower potential was estimated at 35 MW in 2015.[9] Currently, hydropower altogether represents 1.2 per cent of electricity production in Guadeloupe.[7] Since Guadeloupe is seeking energy autonomy, the regional government has the intention to increase the share of hydropower up to 2 per cent by 2030.[15]

FIGURE 3

SHP capacities 2013-2016 in Guadeloupe (MW)



Sources: Guadeloupe Energie,[11] *WSHPDR 2013*,[10] EDF[13]

Renewable energy policy

Guadeloupe has engaged in the establishment of its regional energy sector under the Regional Plan for Renewable Energy and the Rational Use of Energy (PRERURE), which was first published in 2007 and updated in 2012. Guadeloupe, under this plan, aims to achieve energy autonomy through research and innovation, with an important focus on renewable energies. Since the PRERURE defined the energy policy framework in relation to renewable energies, it also established the goal to obtain 50 per cent of electricity from renewable resources by 2020 and 50 per cent of all primary energy from renewable sources by 2030.[9]

Moreover, the Government of Guadeloupe has issued innovative software for the energy calculation of buildings. Other success stories include OVC (off-vehicle charging) vehicles charged with solar panels and electricity generation via sugar cane fibres. Even though 50 undertakings have improved local expertise, the sector continues to be hampered by a lack of training, low demand, a lack of land and insufficient storage.[12]

The following list shows some of the cornerstones of the new policy framework:

- Reduce energy consumption in buildings;
- Reduce energy consumption from big consumer (companies, factories);
- Develop a sustainable transport system;
- Improve the communication, evaluation and observation of the different authorities and entities;
- External cooperation;
- Invest in research and development;
- Training and awareness.

The Government hopes that the implementation of the plan will attract investment in renewable energy projects.

Barriers to small hydropower development

There are several barriers to the development of SHP plants in Guadeloupe. The first one is environmental, as most of the construction needs to follow strict environmental rules and procedures. This can slow down the process. A large part of the water deposit that would be used to install further micro and SHP plants are located near the National Park, which is a protected area. Also, the elevated cost of setting up connections and clearing areas is an important barrier to the development of SHP projects.

2.1.6 Haiti

Martin Camille Cangé, EDH

Key facts

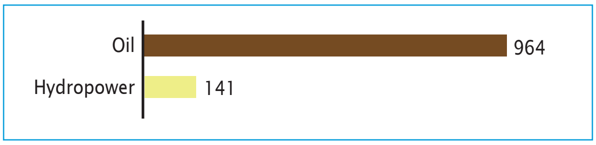
Population	10,400,000 [1]
Area	27,750 km[2]
Climate	The climate is tropical, with some variation depending on altitude. Temperatures in Port-au-Prince range from an average of 23°C to 31°C in January and 25°C to 35°C in July.[1]
Topography	The coastline of Haiti is irregular and forms a long southern peninsula and a shorter northern one, between which lie the Gulf of Gonâve. Rising from the coastal plains to a peak height at La Selle of 2,680 m and covering two-thirds of the interior, three principal mountain ranges stretch across the country. One runs east and west along the southern peninsula while the others stretch north-westward across the mainland. Once-fertile plains run inland between the mountains: the Plaine du Nord, extending in the north-east to the Dominican border, and the Artibonite and Cul-de-Sac plains, reaching west to the Gulf of Gonâve. Of the many small rivers, the Artibonite, which empties into the Gulf of Gonâve, and L'Estère are navigable for some distance.[2]
Rain pattern	The dry season lasts eight months in the north and six months in the south. Rainfall is irregular with annual precipitation of 400-1,000 mm.
General dissipation of rivers and other water sources	The River Artibonite is the longest river on the island at 321 km with 253 km located within Haiti (68 km in the Dominican Republic). It has a drainage basin of approximately 6,339 km[2] located within Haiti. Another important river is the Trois Rivieres with a length of 150 km. Rivers in Haiti flow either into the Atlantic, the Carribean or the Gulf of Gonâve.

Electricity sector overview

The total installed capacity in Haiti is nearly 400 MW, with available capacity at only 244 MW.[8] From this total installed capacity, 138 MW belong to Electricity d'Haiti (EDH) and 200 MW belong to independent power producers (IPPs). Due to the need to save electricity and the low quality of the electricity generated by EDH, a large amount of big consumers (hotels, factories, embassies) choose to produce their own energy through diesel units. The total capacity of these self-producers is estimated at 120 MW.[1] The country's hydropower installed capacity is 62 MW but only 40 MW is operational.[9] Total electricity generation in 2013 was 1,105 GWh (Figure 1).

FIGURE 1

Electricity generation by source in Haiti (GWh)



Source: IEA[13]

The electricity grid in Haiti is not a fully interconnected system but composed of isolated regional grids. The most important grid is the one generating energy for Port-au-Prince, the country's capital where nearly all economic activities take place and where nearly three million people live. The energy sector in Haiti has suffered for a long time due to a lack of a regulatory authority: there is no unique institution managing it. The purchase and distribution of oil products are ensured by the Ministry of Commerce and Industry. The research and identification of primary energy sources, minable resources and the management of the sub-sector for domestic energy are managed by the Mines and Energy Bureau. The generation of electricity is assured by the EDH, a state monopoly under the supervision of the Ministry of Public Works and Communications. There is no institution in charge of regulation nor in charge of rural electrification yet.[1]

There is a consensus on the need of restructuring the energy sector as well as revising corresponding regulations. Thus, working groups have been created in order to define the legal and institutional framework. The new framework should take into account the role of private investors in the development of this sector and especially of renewable energies.

The energy sector is characterized by large-scale utilization of biomass and a very strong dependence on imported oil products.[2] Firewood and wood coal cover 80 per cent of the needs of the population. The reliance on firewood for cooking and lighting has caused deforestation, which has exacerbated the electricity problem by increasing sedimentation and thus reducing the Péligre hydropower station (54 MW) to half its operational capacity.[9] The remaining 20 per cent of energy demand is met by imported petroleum products, which consume more than 50 per cent of the country's import capacity and weigh heavily on the Haitian economy.[1] Propane Gas is also used to for kitchen stoves, but within the cities and on a small scale. Renewable energy sources (solar energy, wind power) are abundant but still not developed.

Approximately 38 per cent of the country's population have access to electricity, but only 15 per cent in rural areas.[14] Due to the hilly topography of the country, connection of rural areas to the unified grid will remain unlikely for a long period of time.

As of 2015, electricity tariffs in Haiti were as follows: US$0.28 for residential consumers, US$0.37 for commercial consumers, public authorities and public lighting, and US$0.39 for industrial consumers.[8]

Small hydropower sector overview and potential

While there is no official definition for small hydropower (SHP) in Haiti, the Ministry of Public Works, Transports, Energy and Communications, in the outline of the Expression of Interest to Participate in the Scaling Up Renewable Energy in Low Income Countries Program (SREP), provided a definition of SHP as plants that have a capacity of 1 MW to 10 MW. Micro and pico hydropower were defined as having a capacity of 0.1 MW to 1 MW and less than 0.1 MW respectively.[9] The total installed SHP capacity up to 10 MW in Haiti is 6.95 MW, while the current available capacity is 3.3 MW (Table 1).[11] According to EDH, the untapped SHP potential is 13.95 MW. However, Worldwatch Institute, using 2011 data from Soleo Energies 2011, estimates it to be 102.3 MW (Tables 2 and 3).[11,7] This report uses the more recent data of 13.95 MW, therefore, the country's total SHP potential can currently be estimated at 20.9 MW (Figure 2).

TABLE 1

SHP plants in Haiti (MW)

Region	Site name	Installed capacity (MW)	Available capacity (MW)
Le Grand Nord	Caracol	0.80	0.5
	Drouet	2.15 (1.5 + 0.65)	1.0
	Délugé-Lanzac	1.10 (0.8 + 0.3)	0
Le Grand Sud	Saut Mathurine	1.60 (0.8 x 2)	1.4
	Gaillard	0.50	0.40
Centre Ouest	Onde-Verte	0.80 (0.65+0.15)	0

Sources: UNDP,[10] EDH[11]

TABLE 2

Hydropower potential sites in Haiti

Name	Location	Capacity (MW)
Dos Bocas	HAI/DR Border	90
Guyamouc	HAI/DR Border	22
Guayamouc	Thomonde El Baye	34
Guayamouc	Thomassique	21
Art 1	Verettes	32
Art 2	Deschapelles	56
Art 4C	Mirebalais	30
La Thème	Mirebalais	0.67
Pichon 1	Belle Anse	0.4
Pichon 2	Belle Anse	0.68
Casales 1	Casales	0.89
Casales 2	Casales	0.47
Samana	Samana	0.78
Bassin Bleu	Bassin Bleu	0.43
Ti Letang	La Vallee de Jacmel	1.4
Voldrogue	Voldrogue	0.23
Saut du Baril	Saut du Baril	0.37
3 Rivières	Trois Rivières	1.18
3 Rivières	Trois Rivières	0.73
GA-4.2	Grande Anse	1.21
GA-35.4	Grande Anse	0.97
GA /BD-8.6	Grande Anse	1.06
GA/BD-15.4	Grande Anse	2.48
Total		298.95

Source: EDH[11]

TABLE 3

SHP potential in Haiti

Number of sites	Small hydro (1-10 MW)	Micro hydro (0.1-1 MW)	Pico hydro (< 0.1 MW)	Capacity (MW)	Generation (GWh/y)
140	27	72	41	102.3	896.5

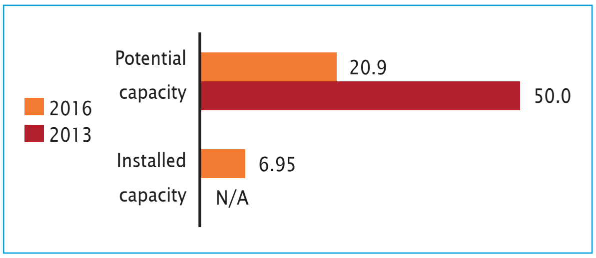
Source: Lucky et al.[7]

Hydropower is the most developed renewable energy in Haiti. EDH operates seven hydropower plants. Six of these plants are small-scale plants. T Peligre is the oldest plant (1971) while the SHP plant of Deluge-Lanzac is the most recent (1989).[2]

Over the years, the available capacity of plants has decreased due to the ageing equipment and the lack of maintenance. However, rehabilitation works are being carried out at the hydropower plant of Peligre. This

FIGURE 2

SHP capacities 2013-2016 in Haiti (MW)



Sources: Electricity d'Haiti,[11] Lucky et al,[7] *WSHPDR 2013*[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

project is funded by the Inter-American Development Bank, the KfW Development bank and the OPEC Fund for International Development.

A feasibility study was carried out for the refurbishment of the Drouet hydropower plant. The financing of the study, including the supervision and the realization of the works, was assured by the World Bank through the ongoing PRELEN project.

Aside from the existing hydropower facilities in operation, there is a sizable hydroelectric potential that can be harnessed. In 1976, through the Canadian International Development Agency, a survey of potential sites was carried out by the firm Lalonde Girouard Letendre and Associates. This survey identified 28 sites totalling 93,356 kW. From this survey the sites of Caracol and Saut-Maturine were developed. Over the years, a few more sites have been added to the list, with the most notable one being the site of Dos Bocas on the Artibonite River at the Haitian-Dominican border. This site could easily exceed 50,000 kW and have an energy production of 292.0 GWh a year. However, it will require a bilateral agreement between Haiti and the Dominican Republic. This potential is more extensive and they are many sites that have not been evaluated.

According to the most recent estimate by EDH, there are 23 potential hydropower sites ranging from pico to large with a combined untapped potential of 298.95 MW (Table 3).[11]

Renewable energy policy

The country's energy sector development follows the Strategic National Plan for the Development of Haiti (SPDH), which has set the target of becoming an emerging economy by 2030 and, inter alia, envisages improving on-grid electricity services in urban areas and surroundings and supporting off-grid electrification in rural areas.

The present National Development Plan for the Energy Sector recommends specific measures for the period 2007-2017. These measures include the promotion of renewable energies (wind, solar, biofuels) and the creation of an additional capacity from renewable energy sources of about 40 MW. However, this plan was prepared before the 2010 earthquake, which significantly changed the country's needs in terms of energy development. The plan is is now therefore rather outdated. As a result of the earthquake, a wide range of electricity infrastructure was damaged or destroyed, resulting in a larger focus on short- and mid-term priorities, in particular rebuilding the country's infrastructure. After the completion of this reconstruction, the Government has reverted to the priorities set by the SPDH. The updated vision for the electricity sector development will be reflected in the new Electricity Master Plan 2015-2030.

The government has accorded great importance to promoting the development of renewable energy sources. Former President Michel Martelly included energy and environment into his five major priorities and former Prime Minister Laurent Lamothe in 2012 declared that the country will reach a 25 per cent share of renewable energy sources in the national electricity mix by 2020.[9]

The Climate Investment Fund's SREP is seen as an important strategic tool to support the Government in its renewable energy policy. The government has requested SREP funds for a balanced programme that will help it to simultaneously focus on strengthening the power sector, supporting economic growth and expanding access to economic opportunities and improved living conditions in secondary/tertiary towns and rural areas.[4]

Some recommendations have been made in order to strengthen the country's vision for its energy development and increase its influence and effectiveness:

- Emphasize its clear intention to prioritise sustainable energy;
- Adopt ambitious and official sustainable energy targets;
- Synthesize the vision across all relevant institutions and sectors;
- Finalize and officially adopt a national energy policy;
- Improve institutional capacity and administrative effectiveness.[5]

Barriers to the small hydropower development

Although Haiti has a significant hydropower potential, it is not fully developed. There are several barriers for SHP development:[6]

- Absence of a single decision-making authority.
- Absence of a legal framework aiming to facilitate private investment and technical rules facilitating connection in 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.
- Limited data regarding the identified sites with SHP potential. Data needs to be collected on a regular basis and a specific department of engineers with hydropower knowledge should be responsible for its upkeep and dissemination.
- High cost of electricity system development.

2.1.7 Jamaica

Patricia Lewin, National Commission on Science and Technology (NCST); Betsy Bandy and Mark Williams, Ministry of Science Technology Energy and Mining

Key facts

Population	2,950,210 [1]
Area	10,991 km²
Climate	Jamaica has two climatic zones. It is tropical on the windward side of the mountains and semi-arid on the leeward side. Temperatures remain constant throughout the year, averaging 25°C to 30°C in the lowlands and 15°C to 22°C at higher elevations.[2]
Topography	The terrain is mostly mountainous, with a narrow, discontinuous coastal plain. Blue Mountain Peak is the highest point of the Blue Mountain Range at 2,256 m above sea level.[2]
Rain pattern	Average annual rainfall is 1,980 mm. Easterly and north-easterly trade winds bring rainfall throughout the year, depositing most of their moisture on the northern slopes of the axial mountain ranges, with the southern half of the island lying in the rain shadow. Island-wide long-term mean annual rainfall exhibits a characteristic pattern, with the primary maximum in October and the secondary in May. The main dry season lasts from December to April.[2]
General dissipation of rivers and other water sources	The central mountain ranges divide the catchment areas for rivers that drain either to the north or to the south coasts. Surface runoff predominates on outcrops of basement rocks and interior valley alluviums. Perennial rivers, like the Martha Brae River and the White River, have low seasonal flow variability. The Great River and the Blue Mountains basin have varying seasonal flows and low baseflow.[3,4]

Electricity sector overview

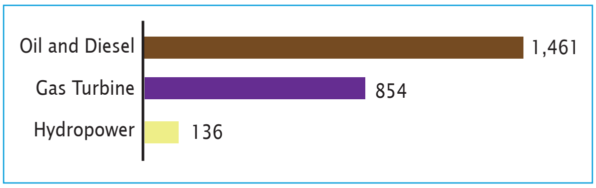
The economy of Jamaica has been chiefly dependent on oil imports, with most of the consumption in the bauxite/alumina, power generation and transportation sectors. Much has been done to diversify its energy consumption with an emphasis on energy security based on domestic renewable energy sources. There is also a thrust to improve the country's energy efficiency and conservation mechanisms.

The electricity generation sector is the country's largest petroleum consumer. Oil and diesel-fired steam generation has a low 29 per cent efficiency rate. Electricity losses on the grid remain high at 22.3 per cent. Ninety per cent of those losses are the result of theft and illegal connections. The National Water Commission is the single largest electricity customer, with electricity costs accounting for nearly 40 per cent of annual revenue.[5]

The Jamaica Public Service Company Limited (JPS) is the country's main electricity provider. According to the 2015 Economic and Social Survey of Jamaica Report (ESSJ 2015), 4,122 GWh of electricity was generated in 2014 (with 1,460 GWh coming from private power purchases), compared to 4,141 GWh in 2013. This decline is the result of a fall in output from non-JPS sources.[6] Though JPS retains a monopoly on the transmission and distribution of electricity, the production regime has been liberalized to include generation of electricity by independent power producers (IPP) for their own use or for sale to the national grid.[7] The JPS company has no renewable energy (RE) mandate and will have to bear any upfront cost of grid modification (if required by a RE generator).[8]

FIGURE 1

Electricity generation in Jamaica (GWh)



Source: Ministry of Science Technology, Energy and Mining[5]

The Government has a vested drive to reduce the country's dependency on imported fossil fuels by infusing renewable sources into the country's energy mix. This is consistent with its policy focus on renewable energy, an estimated 6.3 per cent of the electrical supply mix was attributable to RE during 2014 (Figure 1), compared to 8 per cent in 2012 and 2013. There was a 0.7 per cent increase to approximately 902.8 MW in the country's generating capacity facilitated by the commissioning of JPS Maggotty Hydro Plant in March 2014. This increased its capacity by 1 per cent to 13.5 MW. The commissioning of the Maggotty Hydro Plant further contributed to the overall percentage of net electricity generation from renewable sources.[8] These advances are expected to increase renewable energy input to the national grid by more than 11.5 per cent, thereby advancing the country towards the 2030 target of a 30 per cent share of renewable energy sources in electricity generation.[6]

The Office of Utilities Regulation (OUR), with support from USAID and the National Renewable Energy Laboratory (NREL), completed a study on the Net Billing Program in 2015. This programme allows individuals and companies to generate their own electricity from renewable energy sources and sell any excess to the electric grid operator under terms of Standard Offer Contracts (SOCs) and the supervision of the OUR. The summary on the study highlighted is as follows:

- 316 licenses have been issued of 360 applications, representing potential for 4.8 MW of new generation capacity;
- 120 systems connected to the grid representing approximately 2.0 MW;
- After three years, a review of the programme has been completed and renewed efforts are being made to achieve the target of approximately 12 MW, representing 2 per cent of the system peak demand.

With these efforts, Jamaica can expect its renewable energy capacity to increase to over 200 MW in the next three years.[8]

According to the Ministry of Energy and Mining, the Government of Jamaica has taken steps to facilitate the expansion of the renewable energy industry by providing concessions for the following:

- Reduction of import duty from 30 per cent to 5 per cent on all renewable energy equipment;
- Zero rating for General Consumption Tax (GCT) purposes on renewable energy equipment;
- Payment of a premium of 15 per cent above the curent "Avoided Generation Cost" for the procurement of electrical energy from renewable sources.[9]

The JPS is regulated by the OUR under an incentive-based framework, known as a price cap regime. This framework was introduced through the 2001 Electricity Licence. Under this framework, non-fuel base rates are set once every five years.[9]

The electrification rate now stands at 98 per cent, with the remaining 2 per cent of houses in extremely remote areas. This was made possible through the Rural Electrification Programme (REP), which was recently renamed the Jamaica Energy Solutions Limited (JESL).[10] The JPS produces electricity using steam (oil-fired), combustion gas turbines, combined cycle, diesel, hydroelectric, and wind. With four main power plants across the island, the company has access to approximately 820 MW of total installed generation capacity. This includes close to 197 MW from Independent Power Producers (IPPs). The JPS has eight hydroelectric plants among its mix of generating units, which contribute approximately 30 MW to the grid.[8] There are 12 sites with around 60 MW of generating capacity which have been identified as potential for hydropower development (Table 1).

TABLE 1

Hydropower overview in Jamaica

Site	Status	Capacity (MW)	Production (GWh)
Rio Bueno A	Existing	2.5	13.1
Rio Bueno B	Existing	1.1	5.8
Maggoty Falls	Extension	13.5*	66.1
Upper White River	Existing	3.8	19.9
Lower White River	Existing	4.0	21.0
Roaring River	Existing	3.8	19.9
Constant Spring	Existing	0.8	4.2
Ram's Horn	Existing	0.6	3.1
Great River	Proposed	8.0	42.0
Laughlands	Proposed	2.0	10.5
Back Rio Grande	Proposed	28*	52.5
Green River	Potential	1.4	7.3
Martha Brae	Potential	4.8	36.5
Rio Cobre	Potential	1.0	5.2
Dry River	Potential	0.8	4.2
Negro River	Potential	1	7.5
Yallahs River	Potential	2.6	13.6
Wild Cane River	Potential	2.5	13.1
Morgan's River	Potential	2.3	8.1
Spanish River	Potential	2.5	18.6

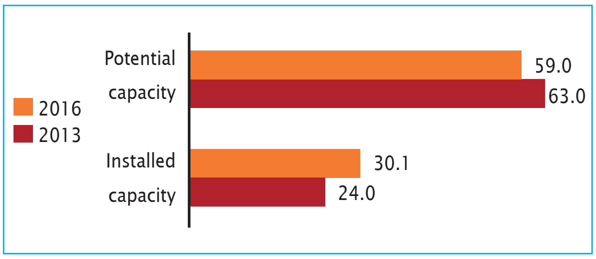
Sources: Ministry of Science Technology Energy and Mining,[12] CaPRI,[8] Petroleum Corporation of Jamaica[11]
Note: Some feasibility data unavailable. An asterisk (*) denotes larger than SHP (10 MW) capacity.

Small hydropower sector overview and potential

Small hydropower (SHP) in Jamaica is defined as hydropower plants with an installed capacity between 1 MW and 10 MW. Installed capacity has increased by 25 per cent (Figure 2) between the *World Small Hydropower Report* (*WSHPDR*) *2013* and *WSHPDR 2016*.

FIGURE 2

SHP capacities 2013-2016 in Jamaica (MW)



Sources: Ministry of Science Technology Energy and Mining,[12] *WSHPDR* 2013,[13] International Renewable Energy Agency[14]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

It should be noted that the 30.1 MW capacity includes all plants under 10 MW as well as the Maggoty plant, which recently had an extension that brought its total capacity above the 10 MW upper limit (13.5 MW). The total SHP potential up to 10 MW, including the Maggoty plant, is at least 59 MW (Figure 2 and Table 1).

Studies were conducted on the Rio Cobre River in St. Catherine, the Negro River, St. Thomas, Martha Brae River, Trelawny and Spanish River, Portland. This was followed by pre-feasibility studies in 2013, which identified a combined potential of more than 20 MW in generating capacity from these sources. Previous assessments of the Laughlands Great River in Saint Ann and Great River in Saint James could create investment packages for the development of about 26 MW in hydropower. If this potential was fully exploited it would double the country's hydro generating capacity combined with the six rivers could result in 95.7 GWh which would reduce the country's oil consumption by more than 56,300 barrels per year, yielding savings of almost US$329 million.[8]

The areas of focus in 2014 included hydropower consisting of the Four River Project, with continued support from the Energy Security and Efficiency Enhancement Project.[8]

Renewable energy policy

Through the Ministry of Science, Technology, Energy and Mining (MSTEM) the Government of Jamaica has been taking steps towards achieving the vision of the National Energy Policy (NEP). The NEP is aligned with Jamaica's National Development Plan, Vision 2030, and seeks to create a modern, efficient, diversified and environmentally sustainable energy sector, which is expected to facilitate the provision of more affordable energy supplies as well as sustainable growth and development for industries.[7]

The National Energy Policy 2009-2030 highlights that energy diversification will involve moving away from an almost total dependence on petroleum to a strategic mix of other sources, including natural gas, coal, petcoke, nuclear, and renewable energy such as solar, wind, and biofuels. Notwithstanding, focus is being given to the development of renewable energy sources such as solar and hydropower as a measure to combat the effects of fluctuation in crude oil prices.[7]

In June 2014 the Cabinet approved the plans of the Electricity Sector Enterprise Team (ESET) regarding the modernisation and diversification of the country's energy infrastructure. The ESET, in consultation with the Office of the Utilities Regulation, the JPS and MSTEM, was tasked to manage the procurement process for new electricity generating capacity. Among its mandates were the Preparation of Optimized Integrated Resources Plan, Selection of Projects for implementation and the development of financing strategies.

The Electricity Act 2015 was recently passed in parliament and now has a section for Renewable Energy Generation. The energy generated from renewable sources are integrated into the grid. Additionally, the draft Renewable Energy Policy will be reviewed to clarify and codify the roles and responsibilities of the main actors in the sector, including the government, the regulator, the utilities and the independent power producers. At the end of the year, work on the proposed amendments was far advanced.

The National Renewable Energy Focus is on Policy Goals to:

- Achieve the development of the economic, infrastructural and planning conditions conducive to RE development;
- Outline the financial and fiscal policy instruments needed and the legislative and regulatory environment;
- Implement the All Island Electric Act (2011);
- Develop and promote technology and introduce renewable energy technologies.

The MSTEM has signed a multimillion-dollar contract from the World Bank, for technical assistance towards the promotion and development of cost effective, SHP projects across Jamaica. The government sees hydropower as a relatively viable solution for the country's energy needs and with its SHP resources playing a significant role in providing low cost energy to the electricity grid, as well as expanding energy access to remote locations.[14]

This will involve feasibility studies, assistance and guidance to key agencies in the administration of hydropower development in Jamaica. The agreement is to also support the development and implementation of departmental policies and procedures, for the effective management of hydropower projects from design, to operation.

The MSTEM announced that there were several sites where SHP capacity could be harnessed for use with about 15 MW of the total 23 MW of SHP potential in the island being considered firm, while the rest is variable, due to seasonal changes in the stream flow.[14] The sites being investigated are the Rio Cobre River (Saint Catherine), Morgan's River and Negro River (Saint Thomas), Martha Brae River (Trelawny) and Spanish River (Portland).

Recent assessments conducted by the United Nations Economic Commission for Latin America and the Caribbean to determine the hydropower potential at 11 sites across Jamaica found that most sites demonstrated a potential capacity of some 2.5 MW or more. This amounts to a total potential of 33.4 MW.[15]

Barriers to small hydropower development

Early studies identified several barriers to the wide scale adoption of renewable energy systems in Jamaica. These include financing, cultural prejudices, the absence of or weak fiscal and regulatory provisions. Possibly the largest barrier to the development of a domestic renewable and cogeneration market is the absence of appropriate protocol to facilitate contracts governing buyer-seller relationships.

The contribution from renewable sources to the electricity sector will be increased from the current level of 6 per cent up to 15 per cent by 2020. Tax policies will be designed to encourage development of the renewable energy sector. The Government will strengthen the legislative and regulatory framework and establish appropriate protocols to facilitate the development of the sector and govern trading relationships including a basis for premium pricing.[15] However, the effectiveness of hydro units depends largely on the availability of water and the quality of the stream flow.

2.1.8 Puerto Rico

Efraín O'Neill-Carrillo, Agustín Irizarry-Rivera and Edy Jiménez-Toribio, University of Puerto Rico Mayagüez

Key facts

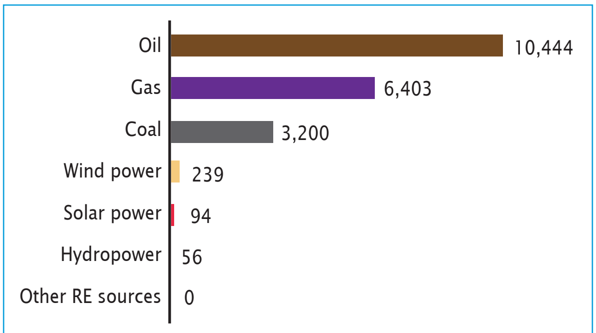
Population	3,548,397[1]
Area	8,870 km^2 [1]
Climate	The climate is tropical marine with warm and sunny weather most of the year. Temperatures fluctuate between 22°C and 25°C. The temperature in the south tends to be a few degrees higher than that in the north. In the central interior mountains the temperatures are cooler than in the rest of the island.[2]
Topography	The territory of Puerto Rico can be divided 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 m above sea level. The second zone is the coastal lowlands that extend 10-19 km inward in the north and south. Finally, the karst region, consisting of formations of rugged volcanic rock, extends in the north of the island.[2]
Rain pattern	Annual precipitation in the north is 1,550 mm, in the south 910 mm, in coastal regions 1,010-3,810 mm and in the mountains 5,080 mm. Rainfall is usually evenly distributed throughout the year but doubles in May to October, whereas January to April are the driest months.[2]
General dissipation of rivers and other water sources	Due to its topography, Puerto Rico does not have long rivers or large lakes. The Grande de Arecibo is the longest river and flows to the northern coast. Other rivers include La Plata, Cibuco, Loiza, Bayamon and the Grande de Anasco.[2]

Electricity sector overview

In 2015, the total generation of electricity in Puerto Rico was around 20,500 GWh (Figure 1). The Puerto Rico Electric Power Authority (PREPA) is a government-owned entity that operates the electric power system in Puerto Rico. PREPA generated approximately 65 per cent of this electricity and purchased the remaining 35 per cent from private generators, mainly EcoEléctrica (liquid natural gas) and AES-Puerto Rico (AES-PR) (coal).

FIGURE 1

Electricity generation by sources in Puerto Rico (TWh)



Source: PREPA[12]

The total dependable electricity generating capacity in Puerto Rico in 2014 was 5,839 MW, with 507 MW from EcoEléctrica (liquid natural gas), 454 MW from AES-PR (coal) and 4,878 MW from PREPA (2,892 MW steam-electric capacity, 846 MW combustion-turbine capacity, 1,032 MW combined-cycle capacity, approximately 100 MW hydropower capacity and 8 MW diesel capacity). PREPA does not include into the dependable capacity the 123.1 MW of installed solar and wind.

Customers are mainly classified as industrial, commercial, institutional and residential. There has been no rate revision since 1989, although minor changes have occurred to include power purchased to EcoEléctrica and AES, as well as accounting for renewable energy credits. There is a fuel adjustment clause that has mainly taken care of fuel price volatility and legislated subsidies.

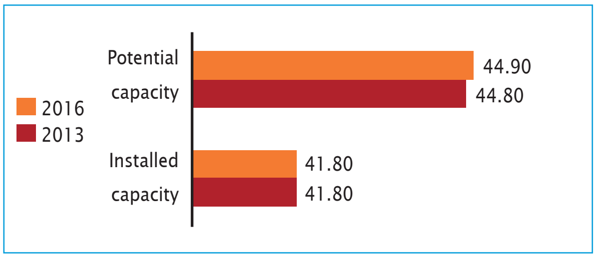
The electrification rate of Puerto Rico is 100 per cent. The country's utility rates are approximately US$0.24/kWh, while the Caribbean region average is US$0.33/kWh.

Small hydropower sector overview and potential

This report for Puerto Rico considers small hydropower (SHP) as plants with a capacity up to 10 MW. In Puerto Rico, 21 hydropower units at 11 locations are operated by PREPA. These 21 units have an aggregate capacity of approximately 100 MW. In 2015, the hydropower generating units generated 55.9 GWh. The hydropower units had an annualised service factor of 8 per cent.[3] Recent low rainfall and accumulating sediment in the reservoirs have limited the use of existing hydroelectric capacity. Furthermore, many of the units had mechanical problems in 2013, which also accounts for the reduced generation. There are eight SHP plants in Puerto Rico, with an aggregated capacity of 41.8 MW distributed among 15 units with capacities below 10 MW (Figure 2). However, two units in Patillas (0.8 MW units and 0.6 MW units) have not been in service for some time. Table 1 below briefly describes the units below 10 MW and their capacities.

FIGURE 2

SHP capacities 2013-2016 in Puerto Rico (MW)



Sources: *WSHPDR 2013*,[11] Caribbean Water Science Center[6]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The hydrology of small tropical islands differs from that of temperate continental areas. The water flow in a river is critically affected by annual precipitation in a particular zone. The precipitation in the Caribbean, which is the origin of all freshwater resources, is controlled by the easterly trade winds, tropical storm activity and the effects of mountains. The geology, topography, and relative size of the islands determine the degree to which they collect and retain the rainfall that supplies water. Puerto Rico has 224 rivers. The main ones drain into the northern and southern areas. About 67 per cent of the superficial drain is from the central mountain ranges to the northern coast.[4]

TABLE 1

Operational SHP plants in Puerto Rico

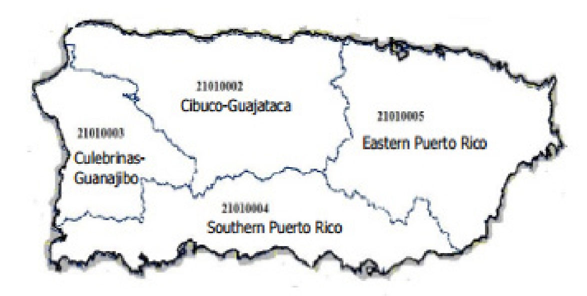
Plant name	Available capacity (MW)	Notes
Toro Negro 1	8.64	(3) 1.44 MW units, (1) 4.32 MW unit
Toro Negro 2	1.92	1 unit
Garzas 1	7.20	(2) 3.6 MW units
Garzas 2	5.04	1 unit
Yauco 2	9.00	(2) 4.5 MW units
Caonillas 2	3.60	1 unit
Rio Blanco	5.00	(2) 2.5 MW units
Total	**40.40**	**13 units**

Source: PREPA[3]

The United States Geological Survey (USGS) divides Puerto Rico into four hydrologic units (HU) as shown in Figure 3. The USGS data was analysed to obtain the average discharge of the main rivers in Puerto Rico (44 in total).[5] Since the natural places for large reservoirs have already been used, an area of growth for small hydro is the micro hydropower (units not exceeding 100 kW in capacity). The potential for micro-hydropower generation was determined using water flow and net head. A net head range from 3 to 120 m was considered due to variations from river to river or from location to location in the same river. Table 2 shows the estimate of micro hydropower generation capacity.[6] This is a conservative estimate.

FIGURE 3

Map of hydrological units in Puerto Rico



Source: US Department of Interior[4]

Note that hydrologic units 21010002 and 21010005, corresponding to the north and draining approximately 67 per cent of superficial water, have the highest micro hydropower potential.

TABLE 2

Estimated micro hydropower capacity in Puerto Rico

Hydrologic unit	Available capacity (kW)
21010002, Cibuco-Guajataca	1,067.00
21010003, Culebrinas-Guanajibo	101.00
21010004, Southern Puerto Rico	766.00
21010005, Eastern Puerto Rico	1,148.00

Source: Puerto Rico State Energy Office[5]

The total micro hydropower potential of all hydropower units is approximately 3.1 MW, a small amount since it is 3 per cent of the total installed hydropower capacity. This was the first attempt to estimate micro hydropower potential in Puerto Rico.[5] Not all potential sites were included in the estimate since many potential sites are not monitored. Nevertheless, this lower-limit estimate for such potential should motivate more extensive field work and data analysis in Puerto Rico to obtain a more accurate estimate.

Renewable energy policy

The Net Metering Act of 2007 has been the most effective law to date in promoting change in the energy sector and reducing the country's dependence on fossil fuels. It allowed users to operate their own generation up to 1 MW and sold back to the utility any excess power.[7] The programme was expanded in 2012 to increase eligible generation to 5 MW. Another action that helped increase distributed generation in Puerto Rico was Act 83 of 2010,[8] which provided partial refunds to selected users that installed renewable energy systems in their premises. In early 2015, there were about 37 MW of distributed generation in Puerto Rico, mainly solar PV systems. From PREPA estimates, that number jumped to close to 70 MW by mid-2015.

Act 82 of 2010 mandated renewable energy targets of 12 per cent by year 2015, 15 per cent by 2020 and 20 per cent by 2035.[9] However, as seen in Figure 1, total renewable energy generation was barely 1.5 per cent in 2015. Even though the legal framework had been established, there was no effective coordination of renewable energy policies with PREPA, nor consideration of the technical, financial and contractual difficulties of interconnecting utility-scale renewable energy. Although Act 82-2010 was passed, PREPA's mission remained the same, yet with no clear directive to integrate renewable energy policies.

Act 57 in 2014 tried to harmonise the goals and legislative actions towards renewable energy and the need for transformation in the electric sector.[10] It gave PREPA a direct and clear new mission of contributing to the sustainability of Puerto Rico, promoting renewable energy, conservation and energy efficiency. It directed PREPA to transform the electric infrastructure of Puerto Rico to enable the maximum level of renewable energy use, in particular at the distribution level. Act 57 also created a new regulator for the electric industry, a new utility consumer advocate and reformed the island's energy office. Unfortunately, as the law was signed in May 2014, a debt over US$9 billion (mostly in the municipal bond market) created a financial crisis for PREPA. Creditors agreed to give time to PREPA to create a restructuring plan for the company. The plan was presented on June 2015, and negotiations yielded a final plan by September 2015. By the end of 2015, the restructuring plan was halted until local legislation is passed to allow its execution. At the same time, PREPA must comply with Act 57 requirements of rate revision and an integrated resource plan for the second half of 2015, with oversight from the new regulator.

Barriers to small hydropower development

In the short term, an increase in SHP generation could come from improvements in PREPA's existing hydro units and also through micro hydropower connected through net metering or in stand-alone mode.

Since PREPA is going through a restructuration of its US$9 billion debt (mostly bonds in the US municipal bond market), a possible scenario to increase the use of hydropower is a private investment scheme where PREPA will retain its hydro assets and secure private investment to improve and expand its hydro generation. The private investor would receive a negotiated return on investment secured by the generation. Since hydro power is currently the cheapest electricity produced by PREPA, at around US$0.02/kWh, there is margin to secure a reasonable agreement for the investor and the people of Puerto Rico.

Puerto Rico does have SHP potential. However, it is small when compared to other renewable resources (e.g. solar and ocean waves). Some argue that if existing reservoirs were properly maintained (e.g. dredged periodically), new generators put in place and better water management implemented, the potential for SHP could increase threefold. Further increases in traditional SHP are unlikely because of other uses of existing water resources, primarily human consumption, but also tourism and recreation. A more realistic option to increase SHP would be to have distributed, micro-hydro units (in the tens of kW of capacity). Some of the obstacles with micro hydropower include little experience with this option in Puerto Rico, and the division of regulatory oversight among local and federal (USA) agencies that does not present a clear permitting process for hydro alternatives.

2.1.9 Saint Lucia

Marcis Galauska, International Center on Small Hydro Power; Sven Homscheid

Key facts

Population	183,645[1]
Area	616 km[2]
Climate	Saint Lucia has a tropical maritime climate, moderated by north-east trade winds. The average annual temperature is 27°C with rare fluctuations of above 33°C or below 20°C. Temperatures are lowest in December to March and highest in June to September.[2]
Topography	Saint Lucia is a volcanic island with a younger mountainous southern half, and an older and rather hilly northern half. The highest mountain, Mountain Gimie, rises 950 m above sea level. The lowlands and valleys of the island have fertile soil and are irrigated from many streams.[3]
Rain pattern	The wet season is from June to November and the dry season is from December to May. The average annual precipitation is approximately 3,350 mm.[4]
General dissipation of rivers and other water sources	A number of small rivers flow outward from the central highlands to the coast. The principal ones are the Cul de Sac, Canelles, Dennery, Fond, Piaye, Doree, Canaries, Roseau and Marquis. The Roseau River is the longest (20.92 km).[5]

Electricity sector overview

In 2014, installed capacity was 88.4 MW while peak demand was 57.2 MW. Electricity generation was 379.4 GWh, and all electricity was generated using diesel generators, with 100 per cent of diesel being imported.[6] The electrification rate is approximately 98 per cent. Recent years have seen an expansion of the 11 kV distribution network along the west coast and in the north, as well as a 66 kV transmission line that connects the south with the power stations in the north. In line with the electrification of rural inland areas, the distribution network has been expanded and its carrying capacity increased at numerous points.[7] The Ministry of Science and Technology, Energy and Sustainable Development is in charge of energy. St. Lucia Electricity Services Ltd (LUCELEC) is the utility responsible for generation, transmission and distribution of electricity.[4]

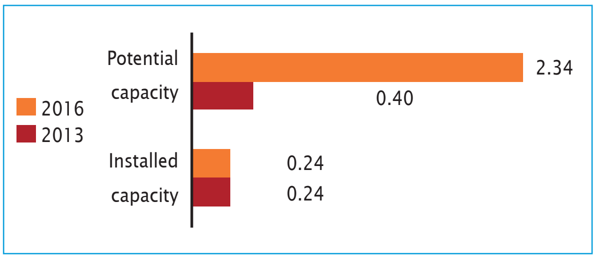
Long-term plans for the energy sector include the construction of a new dual fuel plant. The project was cited for 2015 and consists of four bays fitted with two Wartsila 18V50DF engines running on 99 per cent gas and 1 per cent light fuel oil. It is expected that one additional Wartsila 12V46 would be installed in the Cul De Sac power station. Short-term plans for generation expansion are to install two 1.2 MW Caterpillar portable generators for standby power. The average electricity price before tax to the end-consumer is approximately US$0.33/kWh for domestic users and US$0.37 for commercial/industrial users.[4]

Small hydropower sector overview and potential

There is no clear definition for small hydropower (SHP) in Saint Lucia, but for this report, the definition of less than 10 MW will be used. The only hydropower plant in operation in Saint Lucia is a small 240 kW domestic plant. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, potential capacity has increased due to a new study (Figure 1).

FIGURE 1

SHP capacities 2013-2016 in St. Lucia (MW)



Sources: *WSHPDR 2013*,[11] Caribbean Renewable Energy Development Program[8]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

In 2013, the Caribbean Renewable Energy Development Program carried out research on economically feasible hydropower potential in Saint Lucia. 20 rivers were analysed, using four different feed-in tariffs. At a feed-in tariff (FIT) of US$0.20, SHP potential was identified as feasible on 12 rivers. The overall economically feasible potential with an FIT of US$0.20 is approximately 2.34 MW and the biggest potential capacities were discovered on the Troumassee River (591 kW), the Doree River (390 kW) and the Grande Riviere du Vieux Fort (254 kW).[8]

Renewable energy policy

In 2015, the Government of Saint Lucia announced its goal to generate 35 per cent of electricity from renewable resources by 2020.[9] In early 2016, Saint Lucia renewed its Electricity Supply Act and removed the monopoly for electricity generation from renewable energy sources from LUCELEC, who still holds the monopoly for fossil fuel based generation.

Saint Lucia is a volcanic windward island, with large technical potential for geothermal, wind, and solar renewable energy generation, as well as use of solid waste generated by residents. There is little technical potential for biomass or hydroelectric generation on the island. A biomass plant requires large tracts of agricultural land and is not economically feasible. The island's abundant solar resources (it possesses a global horizontal irradiation of 5.7 kWh per square metre each day, which increases closer to the coast) make solar power economically attractive. The volcano that sits in the middle of Saint Lucia provides vast geothermal potential. Conservative estimates indicate more than 30 MW of technical geothermal potential, while others estimate 170 MW. Estimates also show that development of this geothermal resource would likely be economically feasible.[10]

Barriers to small hydropower development

- Rivers and waterfalls on Saint Lucia do not have a base flow rate sufficient to power water turbines.
- There is no FIT for SHP schemes, which would be fundamental for SHP development.[10]
- Emphasis is put on other renewable energy sources, such as geothermal and solar energy.

2.1.10 Saint Vincent and the Grenadines

Marcis Galauska, International Center on Small Hydro

Key facts

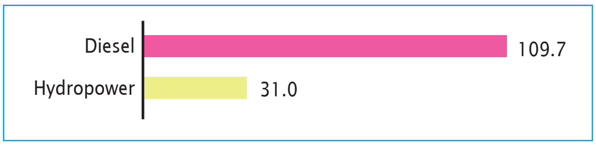
Population	109,360 [1]
Area	389 km^2
Climate	Average annual temperatures are around 26°C with variations of a few degrees between the hottest month at 27°C in September and the coldest month at 25°C in January.[2]
Topography	Saint Vincent is a rugged island of volcanic formation, and the Grenadines are formed by a volcanic ridge running north-south between Saint Vincent and Grenada. The highest peak on Saint Vincent is Soufrière, an active volcano with an altitude of 1,234 m. The low-lying Grenadines have wide beaches and shallow bays and harbours, but most have no source of freshwater except rainfall. The highest point in the Grenadines is Mount Tobai on Union Island, with an altitude of 308 m.[3]
Rain pattern	The annual precipitation varies from 2,000 to 6,000 mm, with total mean runoff of 2,000 to 5,000 mm/year.[4]
General dissipation of rivers and other water sources	The rivers in Saint Vincent tend to be short and straight. The longest river is the Colonarie.[5]

Electricity sector overview

Installed capacity in 2011 was 58.3 MW. Electricity generation was 140.7 GWh, of which 78 per cent came from diesel and 22 per cent from hydro sources (Figure 1). St Vincent Electricity Services Ltd (VINLEC) generates, transmits, and distributes electricity in St. Vincent and the Grenadines' islands of Bequia, Union Island, Canouan, and Mayreau. The other Grenadines islands of Palm Island and Mustique are supplied by privately owned electricity systems using diesel plants as part of their resorts. Peak demand was 21 MW and the electrification rate is approximately 73 per cent.[6] There is a power grid on each island.[4]

FIGURE 1

Electricity generation in St. Vincent and the Grenadines (GWh)



Source: Energy transition initiative[6]

Saint Vincent and the Grenadines (SVG) approved an Energy Action Plan (EAP) in 2010. The EAP forecasts possible energy scenarios in SVG until 2030. It contains short (1-5 years), medium (5-10 years), and long-term (10-20 years) actions which are designed to implement the policies and goals of the National Energy Policy (NEP). These actions foster energy conservation, energy efficiency, and diversification of energy source, including goals such as delivering 30 per cent of projected total electricity output from RES by 2015 and 60 per cent by 2020 and reducing the projected electricity generation by 5 per cent by 2015 and 15 per cent by 2020.[7]

Average electricity tariffs are US$0.22-0.29/kWh for residential users, US$0.29-0.31/kWh for commercial users, US$0.25/kWh to US$0.26/kWh for industrial users and US$0.32/kWh for public lighting.[6]

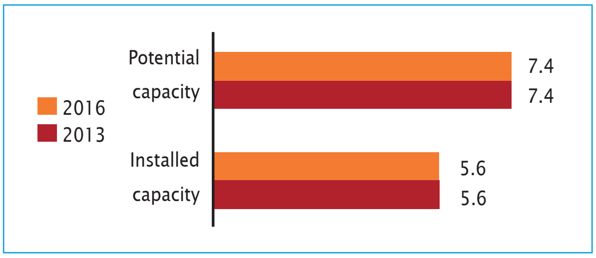
Small hydropower sector overview and potential

The country's definition of small hydropower (SHP) is up to 10 MW. Installed capacity of SHP in Saint Vincent is 5.6 MW. Potential capacity is based on the projects in the phase of development. However, it is safe to assume that the real potential is much larger. Between the *World Small Hydropower Development Report (WSHPDR) 2013* and *WSHPDR 2016*, installed and potential capacity has not increased.

There is 5.62 MW of hydropower capacity in operation at five plants. St Vincent Electricity Services Ltd. (VINLEC) is seeking to refurbish the 870-kW South Rivers hydro plant, which is more than 50 years old, on the Colonarie River. VINLEC signed a contract with Gilkes for rehabilitation

FIGURE 2

SHP capacities 2013-2016 in St. Vincent and the Grenadines (MW)



Sources: *WSHPDR 2013*,[9] IJHD[4]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

work in late 2014. Works are completed for the 1.1-MW Richmond hydro plant rehabilitation, which is located to the east of Chateubelair. VINLEC is also looking into the feasibility of installing a new 1.1 MW hydro plant on the Colonarie River, downstream of the South Rivers plant.[4]

Renewable energy policy

There is a substantial potential for development of electricity from renewable sources. Saint Vincent and Grenadines has a potential for the development of wind, geothermal, biomass and hydro power plants.

The Energy Action Plan for Saint Vincent and the Grenadines includes development plans for renewable energy. The goal is to utilise renewable energy technologies on all islands on Saint Vincent and Grenadines. Proposed policies for development are as follows:

- Promote the increased use of appropriate renewable energy technologies, which are technically and commercially proven, financially and economically viable, and environmentally friendly.
- Analyse the potential of renewable energy sources on all islands, make site-specific assessments and elaborate project proposals.
- Develop local expertise in the production, installation, operation, management and maintenance of technically and economically proven renewable energy systems.
- Encourage private sector participation in the development, financing and management of renewable energy projects.
- Design and initiate a national Renewable Energy education and awareness for all sectors of the civil society.
- Provide financial and fiscal incentives that will allow Renewable Energy technologies to be market competitive, taking into account economic benefits from the use of such technologies.
- Investigate options and potential benefits from importing biofuels to Saint Vincent and the Grenadines.
- Consider the mandatory installation of solar thermal collectors for all major users of hot water.[8]

Barriers to small hydropower development

The main barriers for SHP development are as follows:

- There is no legislation and plan for development of SHP.
- VINLEC holds a monopoly for power generation in Saint Vincent main island and Bequia, Union Island, Canouan, and Mayreau.
- The Government puts emphasis on developing renewable energy from solar power and geothermal sources.

2.2 Central America

José Fábrega, Universidad Tecnológica de Panamá

Introduction to the region

Mexico and Central America comprise a unique region, bordered by the Pacific Ocean to the west and the Caribbean Sea and Atlantic Ocean to the east. The region includes eight countries: Belize, Costa Rica, El Salvador, Guatemala, Honduras, Mexico, Nicaragua and Panama. While the overall geographic nature of the region is narrow, the topography and climate of the region vary widely. Northern Mexico is arid while the southern regions of the country are humid to very humid. For the rest of the region, the climate is defined by altitude and proximity to the coast. For example, in Guatemala, the climate is temperate in areas above 1,000-2,000 m, while the lower regions are tropical, with temperatures that can reach 40°C.[5]

Mexico has 158 river basins with a total mean runoff estimated at 379,000 hm^3/year. In Honduras, the most important river is the Ulúa, which flows 400 km to the Caribbean. In Belize, of the 18 major rivers and many perennial streams, the Belize River is the largest (290 km). In Nicaragua, the Rio Grande and its tributaries are the most extensive river system. El Salvador has 10 hydrographic regions that drain into the Pacific Ocean and the Lempa River. Costa Rica is divided into 34 major basins, 17 basins for each side, with sizes between 207 km^2 and 5,084 km^2. There are 52 watersheds and around 500 rivers in Panama. Most of these rivers (70 per cent) run to the Pacific side (longer streams), with the other 30 per cent running to the Atlantic side. The most important river in Panama is the Chagres River, which forms the basis for the Panama Canal.

River streams define many borders in Central America. The Coco River runs along the Nicaragua/Honduras border, and the San Juan, Lempa and Sixaola Rivers represent part of the Nicaragua/Costa Rica, El Salvador/Honduras, and Costa Rica/Panamá borders respectively. Rivers define half of Honduras' international borders. Finally, it is important to mention that the Lempa River basin composes half of El Salvador and its watershed is shared by El Salvador, Honduras and Guatemala.[5]

An overview of the countries in Central America is presented in Table 1. Mexico alone accounts for 55 per cent of the regional share of installed small hydropower (SHP) (Figure 1). Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, the installed SHP capacity in the region has increased by 42 per cent from 598.5 MW to 855.2 MW, largely due to developments in Guatemala, Mexico and Panama (Figure 2).

TABLE 1

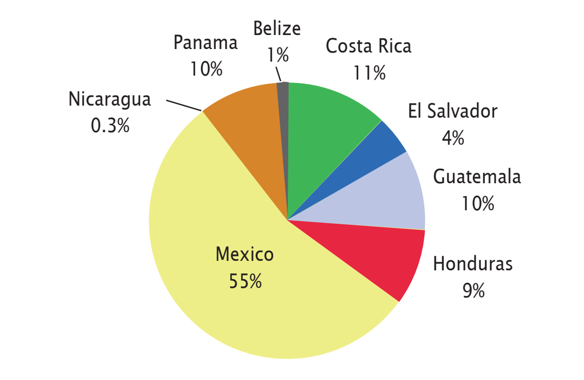
Overview of countries in Central America (+ % change from 2013)

Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Belize	0.34 (0%)	56.3 (+8.3pp)	90.0 (+5pp)	141 (-2.1%)	621 (+60%)	54.5 (+2.8%)	250 (0%)
Costa Rica	4.8 (+3.0%)	23.5 (-12.5pp)	99.4 (+0.01pp)	2,682 (-13.7%)	10,201 (+5.1%)	1,662 (-1.1%)	7,254 (-0.1%)
El Salvador	6.1 (+1.6%)	33.7 (-2.3pp)	93.7 (+7.3pp)	1,583 (+20.6%)	5,876 (+1.9%)	487 (+3.1%)	1,768 (-14%)
Guatemala	14.9 (+3.5%)	52.4 (+1.4pp)	86.3 (+5.8pp)	3,170 (+26%)*	9,920 (+21.7%)	997 (+11.8%)	4,654 (+24%)
Honduras	8.7 (+14.4%)	38.0 (-10pp)	82.2 (+11.9pp)	1,850a (+7.4%)	8,141.6 (+14.2%)	623.5 (+17.4%)	2,597 (-15%)
Mexico	121 (+7%)	21.7 (-1.3pp)	98.4 (+0.7pp)	55,086 (-9.9%)	258,256 (-11.4%)	12,294 (+6.5%)	38,145 (+6.5%)
Nicaragua	5.9 (+2%)	42.2 (-0.8pp)	77.9 (+5.8pp)	1,275 (+42%)	4,163 (+10.1%)	119.4 (+13.3%)	456 (+39.8%)
Panama	3.7 (+4.2%)	38.2 (+13.2pp)	90.9 (+2.8pp)	2,828 (+18.2%)	9,256 (+17.7%)	1,623 (+20.1%)	N/A (-)
Total	**165 (+6%)**	—	—	**68,615 (-4.9%)**	**306,434 (-8.3%)**	**17,860 (+7.5%)**	**55,124 (—)**

Sources: Various[1,2,3,4,5,6,7]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.
Note: An asterisk (*) indicates data were referenced from the 2013 country report, not the regional report.

FIGURE 1

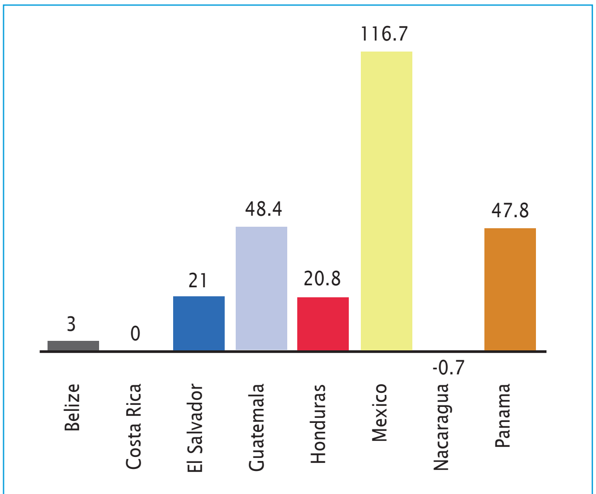
Share of regional installed capacity of SHP by country



Source: *WSHPDR 2016*[5]

FIGURE 2

Net changes in installed capacity of SHP (MW) for Central America, 2013-2016



Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.

The Central American Electric Interconnection System (SIEPAC) has been set up to create an integrated electricity market among El Salvador, Guatemala, Honduras, Costa Rica, Nicaragua and Panama. Once the installation of the SIEPAC line is finished, member states can exchange energy up to 300 MW. Besides the SIEPAC, a transmission line of 103 km has linked Mexico and Guatemala since April 2010. It has a capacity of 200 MW towards Guatemala and 70 MW in the opposite direction

These strategic projects allow energy transfers to the SIEPAC countries to serve the Regional Electric Market of Central America. Mexico is also connected to Belize by a transmission line with a capacity of 65 MW. To the north, Mexico has 11 interconnections with Texas and California in the USA. The capacities of those interconnections range from 36 to 800 MW. Great interest existed in a 2012 plan that would link Panama and Colombia through a 614 km interconnection. However, this project has yet to be realized.[8,9]

The reduction of electricity tariffs and the inclusion of more renewable energy (RE) sources might become a major political challenge in the future. Except for Mexico (US$0.082/KWh), electricity tariffs are high in most countries of the region. Costa Rica has increased its rate from US$0.07/KWh in 2005 (at the time, the cheapest in the world) to US$0.17/kW in 2015. The opposition to new hydroelectric projects by the local population (native groups in many cases) is another political challenge that the region is facing.[5]

Small hydropower definition

The definition of SHP varies throughout the region (Table 2).

Costa Rica does not have an official definition of SHP, but considers installed capacity less than 20 MW to be plants with limited capacity. In Honduras and Belize, there is no definition or consensus for SHP. The rest of the countries have some specific classification, with the highest being a capacity of 30 MW in Mexico.

TABLE 2

Classification of SHP in Central America

Country	Small (MW)	Mini (MW)	Micro (kW)	Pico (kW)
Belize	—	—	—	—
Costa Rica	"Limited capacity" < 20	—	—	—
El Salvador	Up to 20	—	—	—
Guatemala	Up to 10	—	—	—
Honduras	—	—	—	—
Mexico	Up to 30	—	—	—
Nicaragua	Up to 10	—	—	—
Panama	Up to 10 or 20	—	—	—

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]

Regional small hydropower overview and renewable energy policy

Despite the large number of watercourses in the region and the important role that large hydropower plants play in the energy sector of the region, SHP development has continued to remain a small fraction of overall hydro-generation. There is a large untapped potential, but more feasibility studies need to be conducted in order for many countries to fully utilize their SHP potential. There are several small projects in the Central America and Mexico region related specifically to SHP. For example, 30 MW of SHP is under construction in Honduras; and in Nicaragua, a 142 kW SHP project is under construction with another 2.7 MW planned for the next 10 years.[5]

The most significant developments since 2013 have been in legislation and the development of RE sources. The best example of legislation reform happened in Mexico, where in December 2013, three articles of the Constitution were amended to reform the energy sector. With this reform, the State of Mexico still retains the planning and control of the national electric system, as well as the transmission and distribution of electricity. However, private companies are now allowed to participate in the other activities in the electrical industry. Concerning major RE programmes, in Mexico, the Secretariat of Energy and the National Council for Science and Technology have allocated funds to four Energy Innovation Centres focused on wind, solar, geothermal and ocean RE sources. In 2015, Mexico presented its goals and commitments to reduce in 2030 greenhouse gasses by 22 per cent compared to 2013 levels before the United Nations Framework Convention on Climate Change (UNFCC).[11]

Honduras issued an Electrical Industry General Law in January 2014. This law allows for the liberalization of the electricity market.[10] Honduras also intends to reverse the structure of the electricity sector by 2022 to a ratio of 60 per cent RE and 40 per cent fossil fuel.

In terms of RE development, Costa Rica has heavily invested in the renewable energy sector and has become a world leader in the generation of electricity through RE sources. Costa Rica is focused on becoming carbon neutral by 2021. It also has a Plan for the Expansion of the Generation of Electricity 2014-2035, proposing to develop 414 MW from RE sources (mostly hydro and wind) by 2018. From this total, 327 MW will come from hydropower.[5] Costa Rica has also launched the National Energy Plan 2008-2021, which includes a strategic objective to promote the use of renewable and indigenous (biomass) energy for electricity generation.

TABLE 3

SHP in Central America (+ % change from 2013)

Country	**Potential (MW)**	**Planned (MW)**	**Installed capacity (MW)**	**Annual generation (GWh)**
Belize	21.7 (-57%)	N/A	10.3 (+41%)	N/A
Costa Rica*	91	24	91 (0%)	N/A
El Salvador*	180 (0%)	162.7	36 (0%)	N/A
Guatemala	84	N/A	84 (+136%)	N/A
Honduras	385 (0%)	30.1	75 (39%)	N/A
Mexico*	470	N/A	470.2 (+3.6%)	1,832 (—)
Nicaragua	40 (0%)	2.8	2.2 (-25%)	< 0.001 (0%)
Panama*	147.6 (+20.7%)	N/A	86.6 (+123%)	N/A
Total	**1,512.4**	**219.6**	**855.2 (+42.8%)**	—

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
Note: An asterisk (*) indicates greater than 10 MW definition.
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

In Nicaragua, a key part of the National Development Plan is the 72 MW San Jacinto Project. This is a massive 3,965 ha geothermal power plant expected to generate approximately 17 per cent of the country's total electricity needs at prices 37 per cent below the average wholesale electricity price in Nicaragua. The geothermal generation is already contributing to the National Development Plan of Nicaragua, which calls for 91 per cent of the country's electricity needs to be met by RE sources by 2027.

The national development plan of Belize, called Horizon 2030, includes the promotion of green energy and effective efficiency as one of its strategic priorities. This includes the creation of an institutional framework for producing a viable energy policy. The country's National Sustainable Energy Strategy 2012-2033 aims to institutionalise a countrywide infrastructure to collect data, in order to identify feasible sites for the development of solar, wind and hydropower energy.

In Guatemala, the 2013-2027 Energy Policy includes plans for the promotion of RE resources in electricity generation, with a long-term goal of generating 80 per cent of electricity from RE resources.

In El Salvador, the 2012 revision of the Master Plan for Renewable Energy selected 123 sites out of 209 identified for SHP, while considering protected areas and environmental concerns.

In Panama, high prices and consumption levels of energy lead to the promulgation of Law 44 of April 2011, which aims to promote wind power and diversity in RE sources. According to the National Energy Plan, incentives are being applied in order to comply with the Kyoto Protocol (it may have to be adapted to the new COP 21 agreements).[12]

Barriers to small hydropower development

There are two major challenges to SHP development are found throughout the region:

- Lack of solid financial frameworks for SHP investments. This is common to all countries and translates in limited funds made available by commercial banks (i.e. Mexico and Honduras), or short term loans at high interest rates (i.e. Guatemala and Nicaragua).
- Need for better policies and legislation to promote SHP projects. This is fostered by policies and interest

groups focused on promoting fossil-fuel-fired energy projects (i.e. Mexico and Honduras). Also, even within RE sources, there seem to be preferences for the development of other types of RE projects (i.e. Mexico, Panama and El Salvador). Even in Panama, which possesses a favourable legal framework, the SHP sector development is not significant. Since SHP projects are small, incentives are necessary to level disadvantages such as proportionally more expensive permits and environmental impact studies (i.e. Costa Rica, Mexico and Nicaragua).

Besides these two major barriers, it is important to also consider other situations such as:

- Lack of reliable river flow data series and detailed hydropower potential inventories;
- Unregulated markets and lack of standards (i.e. Belize);
- Land rights issues (i.e. Guatemala);
- Limits to private investors participation in energy generation (i.e. Costa Rica).

2.2.1 Belize

Henrik Personn, Caribbean Community Climate Change Centre

Key facts

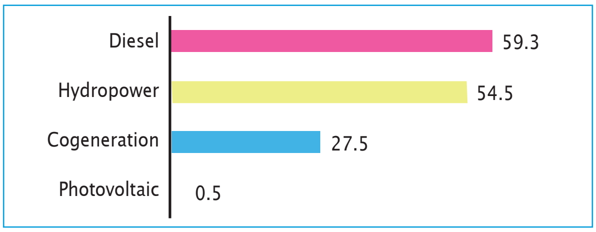
Population	348,033[1]
Area	22,966 km^2 [2]
Climate	The climate is tropical, hot and humid. Temperatures range from 10°C to 35°C. November through January are traditionally the coolest months, with an average temperature of 24°C. May to September are the warmest, with an average temperature of 27°C. In Cayo, in the west, temperatures can be several degrees colder than along the coast, with night-time temperatures sometimes falling to below 8°C during November.
Topography	The north of Belize is a flat, swampy coastal plain while the south contains the low mountain range of the Maya Mountains. The highest point is Doyles Delight, at 1,160 m.[3]
Rain pattern	The rainy season is from May 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 the north can be less than 1,800 mm.
General dissipation of rivers and other water sources	Eighteen major rivers and many perennial streams flow through Belize. The largest river is the Belize River (290 km), which flows along the northern edge of the Maya Mountains through the centre of the country to the Caribbean and drains more than one-quarter of the surface area. Other important rivers include the Sibun River, which drains the north-eastern edge of the Maya Mountains, and the New River, which flows through the northern regions before emptying into Chetumal Bay.[4]

Electricity sector overview

In 2014, the total installed capacity of licensed power producers was 141.78 MW. Approximately 42 per cent was contributed by diesel generators, approximately 39 per cent by hydropower and 19 per cent by a cogeneration plant utilizing bagasse and heavy fuel oil (HFO). A small photovoltaic plant of 480 kW also feeds the grid (Figure 1). A full list of operational power plants is given in Table 1.[5,6]

FIGURE 1

Installed electricity capacity in Belize by source (MW)

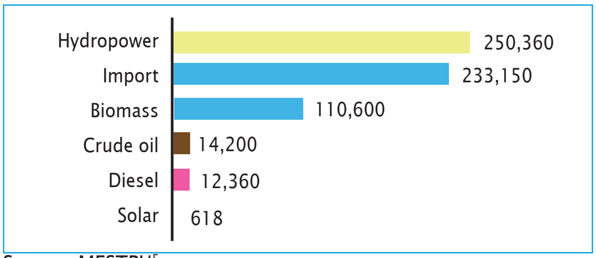


Source: MESTPU[5]

In 2014, 30 per cent (3,948 TJ) of the total primary energy supplied generated 621,288 MWh of electricity. This consisted of approximately 40 per cent (250,360 MWh) from hydropower, 18 per cent (110,600 MWh) from biomass (baggase), 2.3 per cent (14,200 MWh) from oil, 2 per cent (12,360 MWh) from diesel, and less than 1 per cent (618 MWh) from solar. Additionally, 233,150 MWh, or approximately 38 per cent was imported from the Mexican state-owned power company, Comisión Federal de Electricidad (CFE) (Figure 2).[5]

FIGURE 2

Annual electricity generation in Belize by source (MWh)



Source: MESTPU[5]

The Ministry of Energy, Science and Technology and Public Utilities (MESTPU) is the main authority on energy in Belize, while the Belize Electricity Limited (BEL) is the holder of a license, granted by the Public Utilities Commission (PUC), to generate, transmit and supply electricity in Belize.

The PUC is the regulator for the electricity, water, and telecommunications sectors in Belize. It is responsible for efficiently providing the highest quality services at affordable rates, ensuring the viability and sustainability of each sector.

TABLE 1

List of power plants in Belize (MW)

Name	Installed capacity (MW)	Description
Belize Electric Limited (BEL)	29.10	A diesel-fired gas turbine rated at 22.5 MW, but its actual output is typically 20.0 MW. In addition the utility deploys 6 x 1.1 MW mobile high-speed diesel units at different nodes in their network
Belize Co-Generation Energy Limited (BELCOGEN)	27.50	Generates electricity burning bagasse and heavy fuel oil 1 x 12.5 MW (back-pressure) and 15 MW (condensing/extraction) turbines nominally exporting 13.5 MW into the Grid.
Mollejon Hydroelectric Plant	25.20	Located on the Macal River. 3 x 8.4 MW Francis turbines with a typical output of 8 MW during dry season and 21 MW during wet season
Belize Aquaculture Limited (BAL)	22.50	Owns a power plant that operates 3 x 7.5 MW Wartsila medium-speed diesel units. The facility was initially a self-generator for its aquaculture operations but it is currently providing 15 MW on a standby arrangement to BEL.
Vaca Hydroelectric Plant	19.00	2 x 9 MW and 1 x 1 MW turbines
Farmer's Light Plant	7.70	Operates five diesel generators with rated capacities of 2 x 2.2 MW and 3 x 1.1 MW that run on crude oil.
Chalillo Hydroelectric Dam and Plant	7.30	Located on the Macal River. 2 x 3.65 MW turbines
Hydro Maya Limited (HML)	3.00	Run-of-river plant with units of 1 x 2.4 MW and 1 x 0.6 MW
Photovoltaic Plant at University of Belize	0.48	Grid feeding photovoltaic plant located in Belmopan at the University of Belize Campus.
Total	**141.78**	

Source: MESTPU[5]

The Directorate of Electricity within the PUC was formed by the government in order to focus on regulating all entities that are licensed under the Belize Electricity Act.

Major activities undertaken by the directorate include:

- Annual review (AR) of tariffs each year and a full tariff review (FTR) every four years for the BEL
- Licensees compliance audits
- Reliability and efficiency review for licensees

In establishing the PUC, the government also gave duties and mandates for a commission to enact legislature to regulate the entities involved in the electricity sector. The main legislative instruments used are:

- The PUC Act;
- The Electricity Act;
- Subsidiary legislature on tariffs, fees and charges;
- Licenses issued to entities involved in generation, transmission and distribution of power and energy;
- Other subsidiary legislation such as orders, statutory instruments and by-laws used by the commission to give effect to new tariffs and other legal conditions to be followed by licensees.

The main license holder is BEL, who has the license to generate, transmit and supply electricity throughout Belize. BEL is an incorporated company and, as of 2011, primarily owned by the Government, with a 68 per cent share. As of August 2013, other generation licensees who supply power and associated energy to the BEL National Grid System include: Hydro Maya Limited (hydropower facility), BELCOGEN Limited (bagasse fuel) and BAPCOL (number 6 HFO fuel oil). Other potential entities for inclusion under the regulatory umbrella of the electricity sector include: BECOL (hydro facility), Famer's Light Plant (FPL) Limited (generation and distribution provider) and other small self-generators with size generation of above 75 KW. These entities will be licensed and subsequently regulated by the commission within the next five years.

In December 1998, BEL completed an inter-connection between its transmission system and that of the Comision Federal de Electricidad (CFE) of Mexico. The inter-connection is 115 kV and it completed the existing 115 kV Transmission Grid System. In 2005, BEL completed a 69 KV transmission facility that allowed for the connection of all the southern load centers (Dangriga, Independence/Placencia and Punta Gorda) and completed the existing National Transmission Grid System whereby all load centers in the country were connected except for Caye Caulker.[5]

The national transmission grid currently services approximately 98 per cent of the country's electricity demand. During 2012, the peak demand was 82 MW with net generation requirements of 522 GWh. Caye Caulker remains the lone isolated load centre and is supplied by a diesel power plant. In other remote rural areas and cayes (small, sandy, low-elevation islands) where there are no connections to the grid, households, communities and other entities use a mix of diesel generators, small scale photovoltaic systems or small scale wind turbines to supply electricity for their own needs. According to the 2010 census, 90 per cent of the total households in the country are connected to an electricity supply, including 97 per cent of urban households and 83 per cent of rural households. However, the 2012 data from the World Bank indicates 100 per cent electricity access.[13]

The national transmission grid consists of:

- 115 kV transmission line (approximately 100 miles) running from the XUL-HA substation located in Mexico to the West Lake Substation in Belize, located 8.3 miles on the George Price Highway (previously the Western Highway) from Belize City. Taps are present at the Buena Vista substation and the Maskall substation.
- 115 kV transmission line (approximately eight miles) running from the West Lake substation to the Belize City substation.
- 115 kV transmission line (approximately 100 miles) running from the Mollejon Hydro Plant to the West Lake substation with taps to VACA Hydro Plant, San Ignacio substation, Belmopan substation and the La Democracia substation.

TABLE 2

Tariff rates by type

Tariff type	Tariff (US$/kWh)	Additional charges
Social rate		
0-60 kWh	0.110	Minimum charge is US$2.00
Residential rate		
0-50 kWh	0.165	Minimum charge is US$3.00
51-200 kWh	0.205	
> 201 kWh	0.220	
Commercial 1 (less than 2,500 kWh)		
0-50 kWh	0.165	Minimum charge is US$3.00
51-200 kWh	0.205	
> 201 kWh	0.220	
Commercial 2 (above 2,500 kWh)		
0-10,000 kWh	0.215	Service charge is US$57.50
10 001-20,000 kWh	0.210	
> 20 ,001 kWh	0.205	
Industrial		
Demand of 18 kVA	0.155	Service charge is US$57.50
Demand of 11.25 kVA	0.135	
Street lights	0.235	

Source: BEL[9]

- 69 kV transmission line (approximately 130 miles) running from the La Democracia substation to the Punta Gorda distribution substation, with taps to the Dangriga substation, the BAPCOL generating plant and the Independence substation.

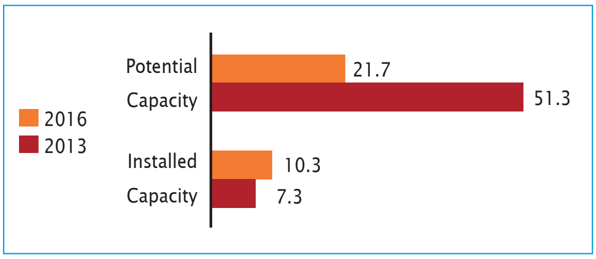
Table 2 provides the tariff rates approved by the PUC from 1 January to 30 June 2015.

Small hydropower sector overview and potential

Belize has no given definition of small hydropower (SHP). This report assumes a definition of 10 MW. The installed capacity of SHP plants below 10 MW is 10.3 MW, with an additional estimated potential of at least 11.4 MW, indicating that 47.5 per cent has been developed.[5,10] Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, the installed capacity has increased by over 40 per cent, while the estimated potential has decreased by approximately 58 per cent (Figure 3).[8]

FIGURE 3

SHP capacities in Belize (MW), 2013-2016

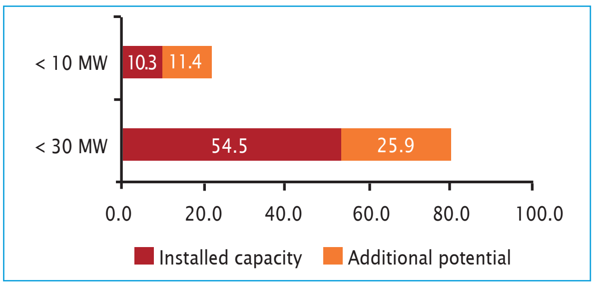


Sources: MESTPU,[5] POYRY,[10] *WSHPDR 2013*[8]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

However, the prior potential estimates were based upon SHP sites of up to 30 MW. With the inclusion of sites up to 30 MW, the potential capacity increases to 80.4 MW. This is a 57 per cent increase. The installed capacity of up to 30 MW includes all hydropower plants in the country, with a total of 54.5 MW (Figure 4).

FIGURE 4

SHP capacities < 10 MW and < 30 MW in Belize (MW)



Sources: MESTPU,[5] POYRY[10]

The installed SHP capacity of up to 10 MW comes from two operational SHP plants: the Chalillo Hydroelectric

Dam and Plant and the Hydro Maya Limited Facility (Table 1). Combined, they account for approximately 19 per cent of total hydropower capacity and approximately 7 per cent of the country's total installed capacity.

While the country's hydropower potential is relatively low, there are still potential sites for further hydropower development without the need to inundate large areas of rainforest for storage reservoirs, as stated in a 2006 study of the country's hydropower potential.[10] Sites with a potential of less than 10 MW listed in the study include:

- The Macal River Project, which has a potential capacity of 8.4 MW and is easily accessible and in proximity to lines of the national power network;
- Tributaries to the Macal River which have the right conditions to install a SHP plant with a capacity of 2 MW;
- Site along the Privassion Rio, which has a potential capacity of 1 MW.

There are also a number of other potential sites across the country. However, no data exists to provide accurate assessments of the potential capacity.[10]

There are no defined financial mechanisms for SHP projects in Belize, but certain incentives do exist. For example, funds or credits for clean energy investments can be applied for with Beltraide or the Development Finance Corporation (DFC). However, neither is specifically focused on SHP.[11,12] Calls have also been issued for Power Purchase Agreements (PPAs) and similar incentives, like the recent call by the PUC in November 2013 to submit proposals to generate electricity to be sold to the government.

Renewable energy policy

The principles of sustainable development are embodied in a national development plan called Horizon 2030. One of the strategic priorities of Horizon 2030 is the promotion of green energy and energy efficiency and conservation, including the creation of an institutional framework for producing a viable energy policy. In February 2012, the government endorsed the National Energy Policy and Planning Framework. The Belize National Sustainable Energy Strategy 2012-2033 aims to institutionalize a countrywide infrastructure to collect data and assess the potential for converting solar, wind and hydropower to electricity, in order to identify feasible sites for development. One of its goals (Goal 5) is to increase hydropower up to 70 MW by 2033. It suggests a revision of the technical assessments of hydropower resource capacity to identify new sources, to determine the potential and to develop expansion plans.

To move forward, the government has conducted several studies that were not public at the time of publishing of this report. These studies will analyse the electricity sector and the needed development in the coming years.

Barriers to small hydropower development

As Belize has no legal framework for renewable energy and grid feeding, the main barrier is the unregulated market, stemming from political considerations and interests. Belize has no Standard Offer Contract (SOC) for renewable energy generation. Investment security is also not automatically given to investors, making the renewable energy market unclear and unregulated. Additionally, Belize has no standards in the SHP sector, resulting in the possibility of technical instability. The skilled workforce for SHP is also very limited in Belize and needs to be explored from other sources. Targeted policy, regulatory, and financial interventions can overcome the barriers that prevent greater development of SHP in Belize, as well as targeted programmes with a focus on SHP.

2.2.2 Costa Rica

Jose Pablo Rojas, CEGESTI

Key facts

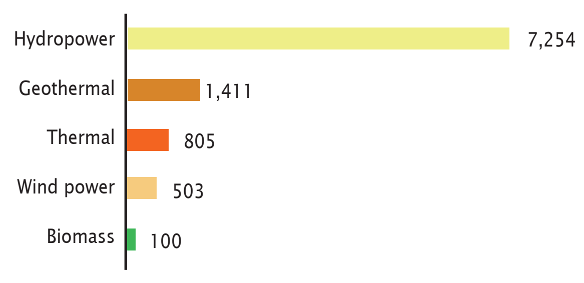
Population	4,870,000 [1]
Area	51,100 km^2
Climate	Most of Costa Rica has two seasons: the wet season from May to November (winter) and the dry season from December to April (summer). Although the country lies completely within the tropics, elevation plays a role in the variations of its climate. Temperature is also determined by proximity to the coasts. The area known as the *tierra caliente* (hot country) in the coastal and northern plains experiences daytime temperatures of 29°C to 32°C. The *tierra templada* (temperate country), including the central valleys and plains, has average daytime temperatures from 24°C to 27°C. The *tierra fría* (cold country) composes the land above 1,524 m and has daytime temperatures from 24°C to 27°C, but night-time temperatures of 10°C to 13°C.[9]
Topography	Mostly flat, with swampy coastal plains and low mountains in the south, the highest point is Cerro Chiripo (3,810 m). The country is divided longitudinally into two hydrographic areas by a system of mountains. These are the Caribbean slope, which is humid and rainy, without water deficit throughout the year and the shed, drier Pacific Ocean, with a marked decline in low water flow.[3]
Rain pattern	During the rainy season, the country receives more than 300 mm each month.[3]
General dissipation of rivers and other water sources	The territory is divided into 34 major basins, 17 basins for each side, with sizes between 207 km^2 and 5,084 km^2. The Caribbean side is wet and rainy, with higher volumes of runoff per unit area without water deficit throughout the year, and the North Pacific has relatively dry basins, with decreased flow in the dry season. The San Carlos and Chirripó Rivers, located near the border with Nicaragua, commonly flood during the wet season, turning the surrounding landscape into swampy marshlands. The largest storage capacity is Lake Arenal (1.9 billion m^3 of useful capacity), followed by Cachí (36 million m^3), Pirris (30 million m^3) and Angostura (11 million m^3).[3]

Electricity sector overview

In 2014, electricity generation in Costa Rica was 10,202 GWh (Figure 1), dominated by non-thermal renewable sources. It is remarkable that approximately 92 per cent of electricity generated in the country comes from renewable sources, with only 8 per cent coming from thermal generation.[8]

FIGURE 1

Electricity generation by sources in Costa Rica (GWh)



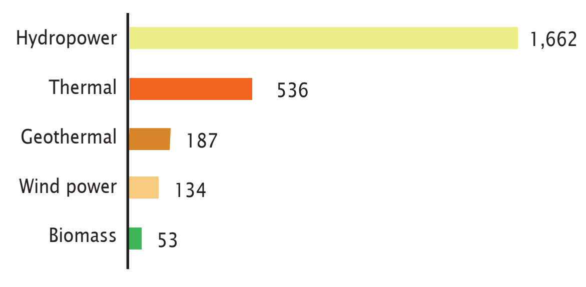
Source: ICE[4]

The Costa Rican Electricity Institute (ICE), which was created in 1949 as per Decree Law No. 449, is a state institution with the legal mandate to provide the electrical power the nation requires for its development. As such, it provides the vast majority of electricity to the country at 74 per cent of generated totals. The electricity sector as a whole is made up of seven public utilities and 30 independent power producers (IPPs). The National Power and Light Company (Compañía Nacional de Fuerza y Luz S.A., or CNFL), which is a subsidiary of ICE, is the principal distributor for the sector.[4]

In 2012, Costa Rica had a total installed capacity of 2,682 MW (Figure 2). The ICE, through power stations it operates, contributed 76 per cent of the total, while IPPs contributed 13 per cent. The remaining 11 per cent came from plants owned by the distribution companies. It should be noted that in the 1970s and 1980s, hydropower was essentially the only source for electricity generation. After a severe drought in 1994, the government diversified generation and began utilizing geothermal, wind, thermal, and recently solar sources to provide stable electricity generation.[8]

FIGURE 2

Installed electricity capacity by sources in Costa Rica (MW)



Source: ICE[4]
Note: Data from 2012.

Costa Rica still utilizes thermal plants for electricity production. During rainy season the generation is minimal, but during the dry season and in times of drought, the thermal plants can keep production matching demand. The electrification rate in Costa Rica is considerable, with 99.4 per cent of households having access to electricity.[8]

Costa Rica participates in the Central American Electricity Market, a regional interconnection of six national markets in a consolidated regional market. Currently the interconnections operate on 230 kV lines. Once the installation of the SIEPAC (Electrical Integration System for Central American Countries) line is finished, member states will be able to have energy exchanges of up to 300 MW.[5]

The distribution and commercialization of Costa Rican electricity is guaranteed by eight public companies. However, the electric system is managed and is under the responsibility of the ICE. The electricity tariffs in Costa Rica are set by the regulatory authority for public services, ARESEP.[6]

Electricity tariffs rose 142 per cent from 2005 to 2015 (US$0.07/kW to US$0.17/kW). At the lower levels, Costa Rica had among the cheapest electricity in the world. In December 2015, the government announced a reduction of 6.7 per cent of the ICE´s average distribution tariffs for 2016. The reduced rate will affect almost 800,000 consumers, including residential, industrial and preferential sectors.[12]

Small hydropower sector and overview

In Costa Rica, there is no definition of small hydropower (SHP). However, plants with installed capacity up to 20 MW are considered to possess limited capacity. For the purposes of this report, the definition will remain as 10 MW or less. Traditionally, the ICE had a monopoly on hydropower production, but IPPs and cooperatives can now invest and operate SHP systems up to 20 MW (Table 1).

In 2009, the installed capacity was 91.25 MW, as reported in the *World Small Hydropower Development Report* (*WSHPDR*) *2013* (Figure 3). Since that time, the capacity has likely increased, but the available data from the ICE continues to demonstrate the capacity of 91 MW (Table 2) from 2009.

TABLE 1

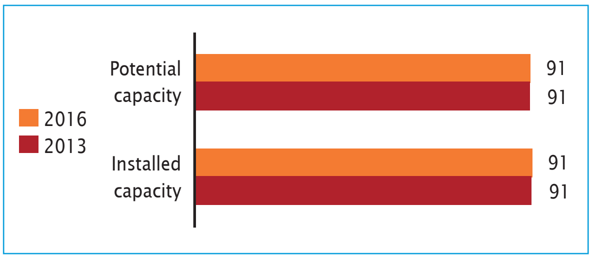
SHP installed capacity In Costa Rica

Public company site	Capacity (MW)	Private company site	Capacity (MW)
Alberto Echandi	4.7	Embalse	2.0
Anonos	0.6	Tapezco	0.1
Avance	0.2	Poas II	1.1
Belen	10.5	La Lucha	0.3
Birris #2	2.4	La Rebeca	0.1
Birris #3	4.3	Poas I	1.6
Brasil	2.8	Montezuma	1.0
Cacao	0.7	Cano Grande	2.8
Carrillos	2	San Gabriel	0.5
Chocosuelas	8.1	Zuerkata	3.0
Electriona	5.8	Quebrada Azul	0.3
La Joya	0.3	El Angel S.A	3.7
Los Lotes	0.4	Matamoros	3.8
Nuestro Amo	7.5	Hidrovenecia	3.4
PTO.Escondido	0.2	La Esperanza	5.5
Rio Segundo	0.3	Rio Segundo II	0.5
Rio Segundo 2	0.5	—	—
Ventanas	10	—	—

Source: ARESEP[6]
Note: Corresponds to 2009 data.

FIGURE 3

SHP capacities in Costa Rica (MW), 2013-2016



Sources: ICE,[1] *WSHPDR 2013*[11]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Costa Rica has massive theoretical hydropower potential, estimated at over 4,000 to 7,000 MW, yet the potential for SHP remains unidentified. While this number suggests the possibility to greatly increase the capacity, the technical and economically feasible potential is lower due to environmental and geographic restrictions. Roughly 1,700 MW of potential are in areas with protected species habitats and another 780 MW are in national parks. While

TABLE 2

Proposed RE installations in Costa Rica

Year	Site	Type	Capacity (MW)
2016	Capulin	Hydro	49
2016	La Joya 2	Hydro	38
2016	Eolico C1 C1a	Wind	50
2016	Orosi	Wind	50
2017	Eolico C1 C1b	Wind	50
2017	Eolico C1 C2	Wind	20
2017	Hidro C1 C1	Hydro	4
2017	Hidro C1 C2	Hydro	50
2019	Pailas 2	Geot	140
Total			**451**

Source: ICE [8]

the former is not prohibited per se, the government must seek concessions with local communities.[6]

In 1990, Act 7200 was adopted, allowing private-sector participation in electricity generation from renewable energy (RE) sources. This law had limited private participation (up to 15 per cent) in the national electric power system. After an amendment by Act 7508, the private-sector participation project limit was raised from 20 MW to up to 50 MW under the Build, Operate, and Transfer modality, which must be executed through tenders by ICE. Importantly, under this law, all projects must use RE.[8]

Renewable energy policy

The Ministry of the Environment and Energy is the state entity for the country's energy planning through the Energy Sector Management Directorate. One of the basic objectives is to diversify the energy mix through the use of renewable energies available at a commercial level. In the National Energy Plan from 2008-2021, one of the strategic objectives is to promote the use of renewable and indigenous (biomass) energy for electricity generation.[10]

The Government of Costa Rica is heavily invested in the renewable energy sector and has become a world leader in electricity generation through renewable sources. The government is dedicated to having the country become carbon neutral by 2021.

According to the Plan for the Expansion of Electricity Generation 2014-2035, distribution companies have proposed plans for developing another 327 MW of hydropower, 67 MW of wind, 10 MW of geothermal and 10 MW of solar, all to be completed by 2018. IPPs currently are eligible for 930 MW (out of 1,250 MW of proposed plans), to include interest in developing hydro and wind units of less than 20 MW.[8]

Legislation on small hydropower

However, independent producers have a cap to production. Per Law No. 7200, the percentage that IPPs can hold of total generation is 15 per cent. With new government RE policies, though, the cap can be raised to include an additional 15 per cent if the production is wholly renewable. This is beneficial for IPPs wishing to develop several SHP sites.

There are recommendations in the Plan for the Expansion of Electricity Generation 2014-2035 issued by the Costa Rican Electricity Institute, with goals and incentives to be implemented in order to cover Costa Rica's electricity needs. The project has put a strong emphasis on RE, in particular one large geothermal plant and several hydropower plants (see Table 2 for a list of projects 2016-2019).

Barriers to small hydropower development

The first barrier regards the difficulties for private investors to develop SHP plants, as well as other renewable energy sources. Currently, the legislation (Law No. 7200) only allows the private sector to generate up to 15 per cent of the installed capacity. Newer policies have increased generation to 30 per cent if it is fully renewable. However, the drawbacks could leave some IPPs without connections to the national grid when that limit is reached.[5]

Barriers to SHP development in Costa Rica are common to barriers encountered by other RE sources. Private developers of electricity generation projects must go through a number of administrative procedures in order to fulfill several documentation requirements of pre-feasibility and feasibility, in addition to obtaining resource use and building permits. They must also sign power purchasing agreements, making the ICE the only possible buyer. The institutional complexity involved in meeting the above-mentioned requirements creates great barriers to the private sector, particularly for small developers.

All hydropower projects, small or large scale, are considered to have potentially high environmental impact and therefore require a full environmental impact study, which is the most complex of the currently existing requirements.[7]

Another problem relates to the establishment of rates for feed-in tariffs. Costs, rules and tariffs were established in 2002, and were stipulated specifically for hydropower plants. Therefore, any technology or alternative energy source must adjust to this reality. Both private developers and the different government authorities are aware of this situation, but have still not reached a consensus on how best to fix it.

2.2.3 El Salvador

Rodolfo Caceres, Consejo Nacional de Energia; Nathan Stedman, International Center on Small Hydro Power

Key facts

Population	6,107,706 [1]
Area	21,040.79 km^2
Climate	El Salvador has a tropical climate with an annual average temperature of 24.9°C. The maximum temperature is 26.4°C in April and drops to a minimum of 23.8°C in December and January due to the northern winds. In the mountainous regions average temperatures range from 10°C to 16°C.[2]
Topography	Roughly 15 per cent of the country is located on the low-lying Pacific coastal region. The remainder of the country is divided into two geographic types, mountains and plateaus. The Sierra Madre mountain chain forms the northern border with Honduras. The western border contains Santa Ana, which is the highest peak (2,365 m). The southern mountains are mostly volcanic. The central plateaus comprise nearly 25 per cent of the territory, and is home to most of the major cities.[3]
Rain pattern	There are essentially two seasons: the dry season from November to April and the rainy season from June to September. The average annual precipitation is 1,800 mm. During the dry season, crops need to be irrigated as only 20 per cent of the annual rainfall occurs during that period.[2]
General dissipation of rivers and other water sources	The country is divided into 10 hydrographic regions that drain into the Pacific Ocean and Lempa River. The biggest is the Lempa Basin, which composes half of the country's area. There are four main storage reservoirs, the largest is Cerron Grande (135 km2) and the smallest is November 5 (16 km2). Five per cent of the territory is wetlands.[2]

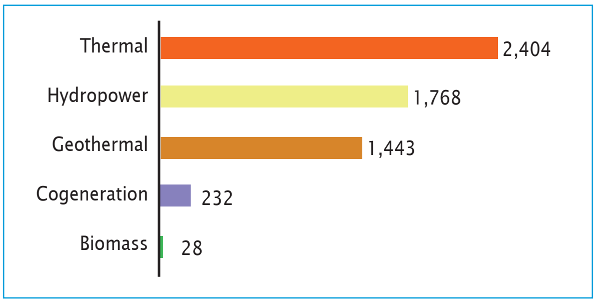
Electricity sector overview

In El Salvador, Unidad de Transacciones (UT) acts as the Independent System Operator responsible for the management and control of the electric transmission grid. The electric distribution grid is privately owned by AES El Salvador. Energy policy is implemented by the National Energy Council (CNE) and regulation of the electricity sector is exercised by the Superintendent of Electricity and Telecommunications (SIGET), both under UT. The regulatory body is the Regional Commission of Electricity Interconnection (CRIE) based in Guatemala City. The Regional Operating Agency (EOR) based in the city of San Salvador is responsible for the dispatch and exchange of energy between countries.[4]

In 2014, total installed capacity was 1.583 GW, where thermal (diesel and fuel oil) took the largest share with 47 per cent (755 MW), then hydro with 30 per cent (487 MW), geothermal with 13 per cent (204 MW), cogeneration with 8 per cent (129 MW) and biomass with the remainder. In the same year, total generation was 5,876 GWh. Thermal was again highest with 40 per cent of generation, hydro constituted 30 per cent, geothermal 25 per cent, cogeneration around 4 per cent and biomass with the remainder (Figure 1).[5] Recently, energy imports have played an important role through the Central America Electrical Interconnection System (Sistema de Interconexión Eléctrica de los Países de América Central, or SIEPAC). Imported oil is the main source of energy for the transportation sector, and for domestic consumption wood is used in rural areas and electricity within cities.

FIGURE 1

Electricity generation in El Salvador (MWh)

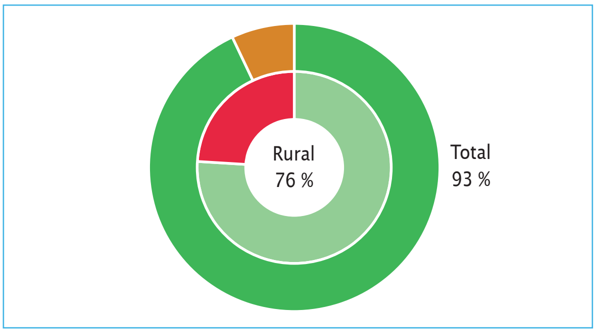


Source: CEPAL[5]

Although El Salvador has an installed capacity of 1,583 MW and maximum demand is 1,035 MW, demand and electricity generation varies with the season of the year. Hydropower constitutes the principal source of energy during the rainy season (50 per cent). By contrast, oil serves as the main generation source (50 per cent) during the dry season. The use of geothermal energy is relatively steady throughout the seasons, at about 20-22 per cent of total generation. With an installed capacity of 50 MW, biomass supplies electricity through private sugar mills. However, production is limited to the harvest season from November to April of each year.[5] The electrification rate is approximately 93 per cent, with 99 per cent access in urban areas and 76 per cent in provincial or rural areas (Figure 2).[7,8]

FIGURE 2

Electrification rate in El Salvador



Source: CNE,[7]AES[8]

Due to the seasonal fluctuations in production, El Salvador varies between an electricity importer and exporter through the SIEPAC network. Guatemala is traditionally the largest exporter of electricity; during the months of January to June, El Salvador is the second largest exporter with a monthly average of 34 GWh, which is roughly 25 per cent of the total exports for that period in SIEPAC. However, El Salvador is also the largest importer of electricity, with roughly 44 per cent of the annual SIEPAC total imports. This is especially true for the months of November and December, where the country contributes roughly 75 per cent of SIEPAC monthly totals.[5]

In 1998, reforms through the General Electricity Law transformed the electricity sector from a state monopoly to a competitive market, thus separating the generation, transmission and distribution of electricity. The Lempa River Hydroelectric Executive Committee's (CEL) thermal and geothermal high voltage plants were sold to private entities. The high-voltage (115 kV) transmission network is owned by an independent company under regulation (natural monopoly) and electricity distribution is concessional, forming four regions held by private investors. In addition, a regional network of electrical interconnection (230 kV) has been set up as the Regional Electricity Market. The law further allows the creation of smaller distribution companies that integrate under UT and are regulated by SIGET.[6]

CEL, as a state company, oversees generation of electricity operations through four hydropower plants with a combined 427 MW installed capacity located in the Lempa Basin. The company continues to conduct studies and develop energy projects namely in the area of non-conventional renewable energies such as photovoltaic energy, wind energy and biofuels.

SIGET is responsible for the implementation of the General Electricity Law to promote free participation and competition in the electricity market in order to gain access and competitive electricity prices for all users. A recent achievement was the tendering and contracting of 94 MW of power and energy from non-conventional renewable energies, including solar PV, valid for 20 years.[7]

Rates remain the same for different types of generation. Every three months, the rates are set by SIGET for each distribution company. Within that period, contracts between such companies and industrial and household consumers may be established. There are neither preferential electricity tariffs nor regionally differentiated prices. Different rates are determined by marketing costs and customer service costs of the different distribution companies across the four regions of the country. In addition, long-term contracts exist between generators and distributors where a constant sales rate is fixed for a determined period. The Government of El Salvador, through the National Investment Fund for Telephone and Electricity (FINET) and financed by CEL, maintains an allowance for end users up to 200 kWh per month.[7] The final consumer price of electricity consists of:

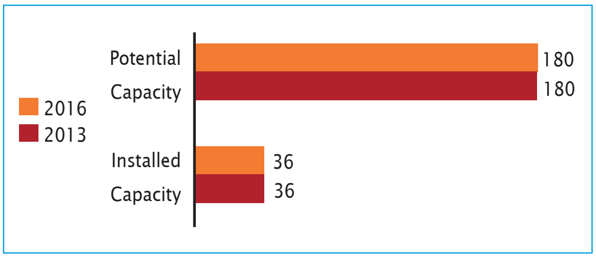
- The price of energy in the wholesale market;
- Marketing costs of the electricity distributor;
- Customer service costs.

Small hydropower sector overview and potential

In El Salvador, the total installed hydropower is 487.55 MW and the potential capacity is upwards of 2,258 (which could result in generating 7,705 GWh/year). The country's definition of small hydropower (SHP) is less than 20 MW, although there are some differences with regulations for 5 MW and 3 MW. The total SHP installed capacity is 35.35 MW (15.55 MW of less than 10 MW capacity), and the potential capacity is 180.8. MW.[10] *WSHPDR 2013*[9]

FIGURE 3

SHP capacities in El Salvador (MW), 2013-2016



Sources: CNE,[10] *WSHPDR 2013*[9]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Since the *World Small Hydropower Development Report (WSHPDR) 2013*, installed capacity and potential capacity has remained unchanged (Figure 3). This indicates that only 20 per cent of potential SHP has been developed.[9]

As of a recent revision to the 2012 Master Plan for Renewable Energy, there have been feasibility studies conducted which identified 209 sites for SHP, most of which were identified in the western regions. After taking into account of environmental concerns and protected areas (SANP), 123 sites have been selected for the Master Plan implementation from 2012-2027. The expected total capacity by the end of phase III in 2027 will be 162.7 MW with a total generation of 671.3 GWh/year.[10]

TABLE 1

SHP in El Salvador (> 20 MW)

Hydro plant	Location	Installed capacity (MW)
Guajoyo	Santa Ana	19.80
Cucumacayán	Sonsonate	2.30
Río Sucio	Santa Ana	2.50
Milingo	San Salvador	0.80
Bululú	Sonsonate	0.70
Atehuasías	Ahuachapán	0.60
Cutumay-Camones	Santa Ana	0.40
Sonsonate	Sonsonate	0.20
San Luis I	Santa Ana	0.60
San Luis II	Santa Ana	0.74
Nahuizalco	Sonsonate	2.80
La Calera	Sonsonate	1.50
Papaloate	Sonsonate	2.00
La Chacra	Morazán	0.02
Carolina	Morazán	0.05
El Junquillo	Morazán	0.01
Miracapa	Morazán	0.03

Source: CNE[10]

Renewable energy policy

The Ministry of the Environment and Natural Resources (MARN) is the responsible institution in the Central Government for socio-environmental aspects, and as such is the largest factor in renewable energy (RE) policy making. In addition to MARN, the Attorney General, National Registry Center, the CNE, SIGET and municipal governments and courts all play a role in the RE policy development and implementation. To date, the most significant policy is the 2012 Master Plan for Renewable Energy.[7]

Legislation on small hydropower

Article 22 of the Environmental Law (Decree No. 579) stipulates that MARN will make classifications on activities and determine the documentation needed to submit proposals. For proposals with moderate to high environmental impact (Group B, Category 2), the investor must submit an Environment Impact Assessment (EIA) to MARN. In addition to the EIA, project holders may have to submit an Environmental Management Plan, to ensure environmental protection during construction of the project and after completion.[7]

The Environmental Law (Articles 78-81 and 85-95), also stipulates protected natural areas. This law was implemented to protect ecosystems and biological diversity and gives the authority to MARN to declare protected areas. As of 2012, there were 69 protected areas, some of which were located in the sites identified for SHP development.[7]

Land Use Decree 855 governs the appropriation and use of land in metropolitan San Salvador. However, local municipal governments refer to the legislation when deciding on land use in the regional areas. Additional permits may be required per this decree. In total, it was estimated to take between 440 and 470 days to receive approval of an EIA from MARN, which would include time needed obtaining other permits.[7] It should be noted that the procedure is the same for all types of projects concerning construction, there is no variation for different RE technologies.

Barriers to small hydropower development

While the country moves forward with the Master Plan for RE, including increasing the role of hydropower in the energy mix, there are still political, institutional and implementation barriers that impede the development of SHP, particularly in the hands of private project holders.

- Lack of basic framework for the development of RE;
- Lack of formalized incentives to promote RE;
- Need to implement technology-specific permits from MARN;
- Lack of MARN experts on RE;
- Expensive environmental studies;
- Inadequate land zoning prevents proper testing;
- Community opposition to projects; the 66 MW El Chaparral and the 261 MW Cimarrón hydro projects have faced considerable opposition, which has hindered development.[11]

2.2.4 Guatemala

Marcis Galauska, International Center on Small Hydro Power

Key facts

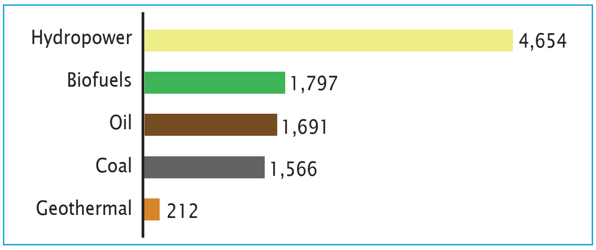
Population	14,918,999 [1]
Area	108,889 km^2 [1]
Climate	Guatemala can be divided into three climactic zones. Daytime temperatures in the tropical lowlands can reach as high as 40°C and temperatures at night rarely drop below 20°C. The temperate zone extends from approximately 1,000-2,000 m above sea level with daytime temperatures rarely exceeding 30°C. The cool zone daytime temperatures are only slightly lower than in the temperate zone, but the nights are fairly cold and temperatures drop below freezing occasionally.[2]
Topography	A tropical plain averaging 48 km in width parallels the Pacific Ocean. A piedmont region rises to altitudes of 90-1,370 m. Above this region lies nearly two-thirds of the country, in an area stretching north-west and south-west and containing volcanic mountains, the highest of which is Tajumulco (4,211 m). To the north of the volcanic belt lies the continental divide and, still farther north, the Atlantic lowlands.[3]
Rain pattern	There are dry and wet seasons: the dry season from May to October and the wet season from November to April. The average precipitation varies from approximately 100-500 mm per month.[4]
General dissipation of rivers and other water sources	The country can be divided into three major areas. The Pacific Rim has 18 river basins. The coast on the Caribbean Sea has 10 basins and includes the most important river, the Motagua. The Gulf of Mexico region also has 10 basins, which are home to the most abundant rivers in the country.[5]

Electricity sector overview

In 2013, electricity generation was 9,920 GWh, with 313 GWh imported and 669 GWh exported, making an overall domestic electricity supply of 9,564 GWh. Of the domestic production, 4,654 GWh was generated from hydro, 1,797 GWh from biofuels, 1,691 GWh from oil, 1,566 GWh from coal and 212 from geothermal sources (Figure 1).[6]

FIGURE 1

Electricity generation in Guatemala (GWh)



Source: IEA[6]

Installed capacity was 3,170 MW. The total electrification rate is approximately 86.3 per cent, while the rate in rural areas is approximately 82 per cent. To assist in increasing electricity access, the Inter-American Development Bank has approved a loan of US$55 million to improve and expand coverage of the national electricity service. The programme is expected to raise the electrification coverage to 92.9 per cent by 2019, through investments in the grid and the installation of isolated systems using renewable energy sources, which will make it possible to connect an additional 6.6 per cent of the population.[7] Guatemala is connected via the Central American Electrical Integration System (SIEPAC) to Honduras and El Salvador. Several communities are located in areas where access to electricity might be delayed due to relief barriers in government assistance programmes, low capacity to pay for the services and lack of transmission infrastructure.[8]

The power market in Guatemala is unbundled, with state and private players acting in generation, transmission, energy trading and distribution segments. The Ministry of Energy and Mining oversees planning for the electricity sector, while the National Electricity Commission (Comisión Nacional de Energía Eléctrica) is in charge of regulation. Additionally, the Wholesale Market Operator (Administrador del Mercado Mayorista), a private organization, organizes the system's dispatch based on marginal cost of generation.[8]

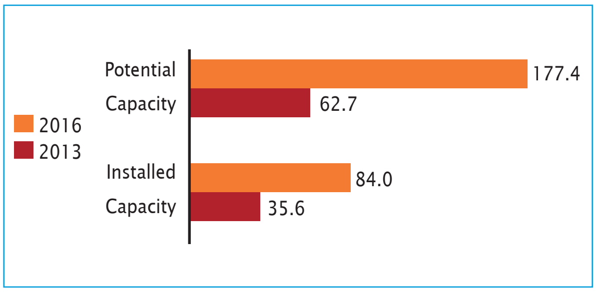
The National Indicative Plan 2008-2022 has set a number of projects to increase power generation, including both non-renewable and renewable sources. Amongst the non-renewable sources, investment is expected in nineteen different power generation plants that include gas and vapour turbines. The average electricity rate in Guatemala is US$0.26/kWh.[9,10]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Guatemala is up to 10 MW. The installed capacity of SHP is 84 MW,[11] while the additional potential capacity derived from the Ministry of Energy and Mines Plan for Generation and Transmission (2016-2030) is 93.36 MW.[17] Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, both installed capacity and potential capacity increased by significant rates (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Guatemala (MW)



Sources: IRENA,[11] Ministry of Energy and Mines,[17] *WSHPDR 2013*[14]
Note: The comparison is between data from *WSHPDR 2013* and *WHSPDR 2016*.

According to the International Renewable Energy Agency (IRENA), installed capacity of SHP in 2014 was 84 MW.[11] Data from ministry records indicate there are approximately 82 hydro plant projects under 5 MW.[12]

The estimated technically feasible hydro potential is 5,000 to 10,800 MW. While data on countrywide potential is not available, the Plan for Generation and Transmission 2016-2030 has a roadmap for developing hydropower over the period of 2016 to 2030; the potential derived from the plans indicates an overall hydropower potential and planned capacity of 3,550 MW, of which 93.36 MW are SHP, indicating a SHP potential of at least that amount.

The Central American Bank for Economic Integration has granted a US$669,000 partial credit guarantee to Financiera de Occidente S.A. to hedge financing for development of SHP generation in Guatemala. The investment anticipates estimated annual generation of 2,751.3 MWh.[13]

Legislation on small hydropower

For SHP project licensing, the operator must obtain temporary water rights from the Ministry of Energy and Mines (MEM) after completing prefeasibility studies. Following the approval, feasibility studies, including hydrology and geology assessments as well as project design and cost estimates, must be carried out and submitted. An environmental impact assessment is also required before the MEM will approve a grid connection study. Final authorization for project implementation is granted by the National Electrical Energy Commission. For projects with capacities up to 5 MW, the water rights staking process consists of registering the project at the Ministry of Energy and Mines. For projects with capacity higher than 5 MW, a 50-year water rights claim must be submitted to the Ministry of Energy and Mines. A safety study is required before construction may begin for all projects with a dam, which must be approved by the National Electrical Energy Commission.[14]

Renewable energy policy

The Energy Policy 2013-2027 is the general energy development plan for Guatemala. It includes plans for the promotion of renewable resources in electricity generation. One of the goals is to diversify electricity generation by prioritising renewable resources; the long term goal is to generate 80 per cent of electricity from renewable resources. The planned actions are:

- To update studies about renewable resource potential of the country;
- To promote hydropower, geothermal, solar, wind, biomass energy as well as other new and renewable energy sources;
- To promote technological innovation and technological development of human capital in the energy sector.

The other objectives are to promote investment in production of 500 MW of renewable energy, as well as to create a Master Plan for renewable energy development.[15]

Estimates of geothermal power potential in Guatemala vary from 400-4,000 MW, biomass potential can be estimated at approximately 500 MW, another 5 MW can be generated by waste products. PV can be developed at a rate of 20 MW per year between 2019 and 2022.[16]

Barriers to small hydropower development

SHP development in Guatemala is strongly hindered by social-institutional barriers, comprising land rights issues between local communities and private developers in natural resource management. Inadequate benefit sharing mechanisms coupled with limited conflict resolution mechanisms have created a significant barrier for SHP development.[18,19]

In addition, Guatemala currently portrays the second lowest Human Development Index in Central and Southern America. The need for rural electrification is thus clear. However, rural electrification is stalled due to ethnic disparities and poverty, which in turn provide a lack of incentive for private investors who are unable to justify high-energy investments within communities with low energy demand and income, thus creating a financial and market barrier to SHP development. SHP development also faces investment barriers, as domestic financing is difficult to obtain due to Guatemala's high interest rates and short loan terms.[18,20]

2.2.5 Honduras

Gonzalo Marzal Lopez, International Center on Small Hydro Power

Key facts

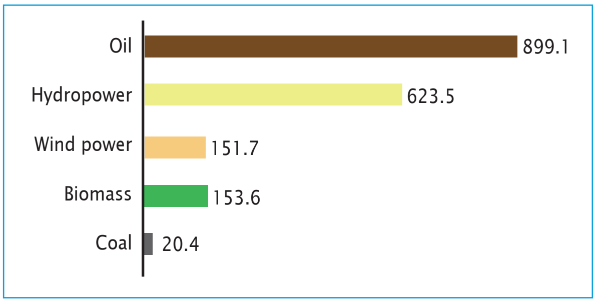
Population	8,762,000
Area	112,491 km^2
Climate	The climate is sub-tropical in the lowlands and temperate in the mountain areas. The warmest month is May, with an average temperature of 25°C, while the coolest month is January, at 22°C.[1]
Topography	The terrain is mostly mountainous in the interior with narrow coastal plains. The highest point is Cerro Las Minas, at 2,870 m. About 80 per cent of the territory is 600-2,850 m above sea level, and 15 per cent is between 150 and 600 m above sea level. About 20 per cent consists of low coastal valleys of the Caribbean Sea and the dry plains of the Pacific coast.[1]
Rain pattern	The average annual rainfall is 1,470 mm. The rainy season is from May to November, with regional variations. Hurricanes and floods are common along the Caribbean coast.[2]
General dissipation of rivers and other water sources	Honduras is a water-rich country. The most important river in Honduras is the Ulúa, which flows 400 km to the Caribbean through the economically important Valle de Sula. Numerous other rivers drain through the interior highlands and empty north into the Caribbean. These rivers are important, not as transportation routes, but due to the broad fertile valleys they produce. Rivers also define about half of Honduras' international borders. The Río Goascorán, flowing to the Golfo de Fonseca, and the Río Lempa define part of the border between El Salvador and Honduras. The Río Coco marks about half of the border between Nicaragua and Honduras.[2]

Electricity sector overview

In 2014, the installed energy capacity in Honduras was 1,850 MW, which consisted of oil (899.1 MW), hydropower (623.45 MW), wind (151.7 MW), biomass (153.55 MW) and coal (20.35 MW). The total generation of electricity in 2014 was 8,141.6 GWh. The generation by sources was as follows: diesel and oil generated 4,713 GW, hydropower generated 2,597 GWh, wind power generated 398 GWh, biomass generated 317 MW and coal generated 113 MW of electricity.[2]

FIGURE 1

Electricity installed capacity in Honduras in 2014 by sources (MW)

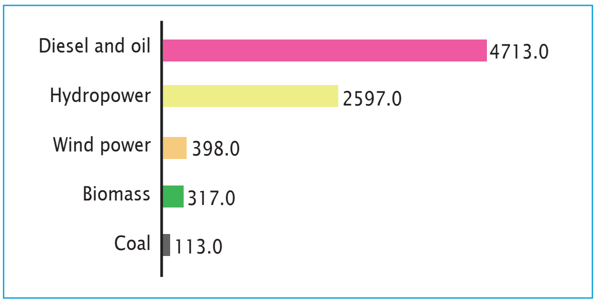


Source: AHPER[2]

The highest authority in the country is the Energy Cabinet. Its main task is to formulate energy policies. SERNA is the government institution in charge of the energy sector, under which there is the National Commission for Energy (CNE) the regulatory authority for the electric energy sub-sector. The national electric power company, the National Company of Electric Energy (ENEE), is owned by the Government and it is in charge of the generation, transmission and distribution of electric energy. It comes under SERNA authority, but is regulated by CNE.[12]

FIGURE 2

Electricity generation in Honduras in 2014 by sources (GWh)



Source: AHPER[2]

The *Ley General de la Industria Electrica* (General Law of the Electric Industry) was issued on 20 January 2014. This law allows for the liberalization of the electricity market in Honduras. It allows for the export and import of energy, creating new business opportunities. Moreover, it allows direct sales of electricity to qualified consumers. The Regulatory Commission of Electric Energy was appointed in June of 2015.[3]

As of the 2012 data provided by the World Bank, the total electrification rate in Honduras was 82.2 per cent.[9]

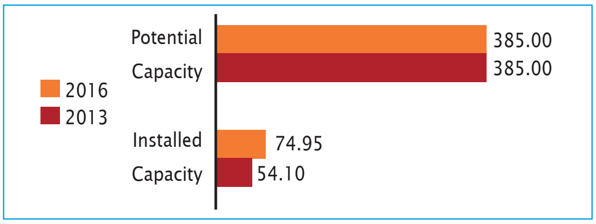
Small hydropower sector overview and potential

The total small hydropower (SHP) installed capacity in Honduras is 74.95 MW.[12] The total SHP potential is approximately 385 MW, with an estimated potential generation of 470.2 GWh/year.[4] There are 21 SHP plants in operation, with a total capacity of 74.95 MW. Moreover, there are 30.13 MW plants of SHP under construction. Currently, there are seven operational SHP plants including the following: Mangungo I (1.2 MW), Mangungo II (1.3 MW), Matarras I (1 MW), Matarras II (2.3 MW), Masca I (1.7 MW), Masca II (1 MW), and Rudiosa I (4 MW).[12]

The total hydropower installed capacity is 623.5 MW and the total hydropower potential is 1,284.2 MW. The Industrial and Commercial Bank of China granted US$299.7 million to the Government of Honduras in order to build the Patuca III project.

FIGURE 3

SHP capacities 2013-2016 in Honduras (MW)



Sources: *WSHPDR 2013*,[11] CIF,[4] IJHD[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Renewable energy policy

The 1998 Legal Framework and Reforms of the Energy Sector Law and its Incentives Law for Renewable Energy Generation have provided incentives for the development of renewable energy. Coupled with Decrees No. 85-89 and No. 267-98, they promote the implementation of renewable energy plants via mechanisms such as tax breaks or tariffs equivalent to short-term marginal costs experienced by the system.[4] In 2007, the Honduran Government issued Decree No. 70-2007 (the Law to Promote Electricity Generation by Renewable Resources), implementing a preferential tax policy and a preferential sales policy for natural and juridical persons who develop and operate renewable energy projects according to the Act 81 of the Environment General Law.[5] It grants additional benefits such as tax exemptions in the forms of import duty and income tax, and improvements in Power Purchase Agreements signed with ENEE to operators who generate electricity from renewable resources.

With all these initiatives, the Government of Honduras intends to reverse the structure of the electricity sector by 2022 to a ratio of 60 per cent renewable and 40 per cent fossil fuel, thus complying with the provisions of the Country Vision and National Plan Law constituted into State Policy by Decree No. 286-2009.[6] The government recognizes the potential of renewable energy technologies to improve industrial, commercial, and residential access to a reliable and affordable grid-connected power; and it is eager to develop these opportunities to enhance the sustainability of energy services in rural areas. Currently, the government's priorities are to scale-up the access to electricity services in rural areas, and to promote rural access to clean energy cooking solutions.

The Honduras Scaling-Up Renewable Energy Program in Low-Income Countries (SREP) is giving US$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 the electricity access in remote areas; promoting access to improved and appropriate cooking technologies; and a policy along with a regulatory reform initiative intended to improve the conditions for development of the country's renewable energy sector.[7]

Legislation on small hydropower

Following the energy crisis of 1994, the Government of Honduras negotiated with the European Commission (EC) in order to promote electricity generation from renewable sources and to encourage energy conservation. In January 1996, a financing agreement was established between the EC and the national electricity utility ENEE. After an initial two-year project, the EC donated EUR 250,000 to create a revolving fund called Fondo de Preinversión Hidroeléctrica (Hydroelectric Pre-investment Fund) that grants loans to the private sector. Since 1999, this ENEE Pre-Investment Fund has helped finance feasibility studies for SHP plants of installed capacity of up to 5 MW.[6]

Barriers to small hydropower development

The equity capacity by private investors in Honduras is concentrated in the larger, fossil-fuel-fired energy projects. It is not common for domestic commercial banks to provide equity to renewable energy projects. Market research indicates that given sound fundamentals (technical viability of project, good contracts, positive and adequate technical studies, competent sponsors) and a resulting reasonably low risk expectation, there are abundant international equity investors and sovereign investors that would be interested in providing equity to renewable energy projects in Honduras.[2]

2.2.6 Mexico

Sergio Armando Trelles Jasso, Mexican Institute of Water Technology

Key facts

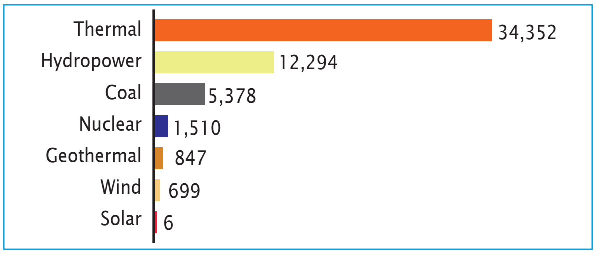
Population	121,005,815[1]
Area	1,964,375 km², including 5,127 km² of islands.[2]
Climate	There is a great diversity of climate in the country due to its extension and relief. It is dry in most of the centre and north (28.3 per cent of the country), very dry in the north-west (20.8 per cent), warm and humid in the south (4.7 per cent), warm and sub-humid along the coasts (23 per cent), temperate and humid in the mountains of the south (2.7 per cent), and temperate and sub-humid in the mountains near the coasts (20.5 per cent).[3]
Topography	The main topographic features evolve from the activity of four tectonic plates. The Peninsula of Baja California is a 1,200 km-long mountainous chain. The Western Sierra Madre is a mountainous chain parallel to the Pacific coast with a length of some 1,400 km, ranging in altitude from 2,000 to 3,000 m. The Eastern Sierra Madre runs parallel but is separated by vast plains from the Gulf of Mexico over some 600 km, ranging in altitude from 1,200 to 3,000 m. The Sonora and Chihuahua Deserts are in the north-west near the border with the USA. The Central High Plateau ranges from 500 to 2,600 m. The Neovolcanic Axis runs from the west coast to the east coast, south of Mexico City, with a peak altitude of 5,747 m. The Southern Sierra Madre extends over 1,200 km and is very close to the south-western coast, with a peak altitude of 3,850 m. The Sierra Madre of Oaxaca in the south-east is about 300 km long, with peaks of about 3,000 m. The Peninsula of Yucatan in the south-east is a relatively flat karst formation with almost no streams or rivers.[4,5]
Rain pattern	From 1971 to 2000, the average precipitation for the country was 760 mm per year. The spatial distribution varies widely from 100 mm in the north-west to 2,350 mm in the south-east. Every year, between July and October, there are tropical storms and hurricanes that reach both littorals. From 1970 to 2012 there were 200 such events, most of them on the Pacific coast, but they were the strongest on the Atlantic coast. The rainy season from May to October accumulates 83 per cent of the annual rainfall.[6]
General dissipation of rivers and other water sources	The country is divided in 37 hydrologic regions, which are further divided into 158 river basins and 976 sub-basins. The total mean runoff is estimated at 379,000 hm³ per year. The five hydrologic regions with the largest runoff are in the south-east: Grijalva-Usumacinta (shared with Guatemala), Pánuco, Papaloapan, Costa Chica de Guerrero and Coatzacoalcos. The five hydrologic regions with the largest extension but with lesser pluviosity than the previous group are: Bravo (shared with the USA), Sonora Sur, Lerma-Santiago, Balsas and Sinaloa.[4]

Electricity sector overview

The total effective capacity in June 2015 was 55,086 MW of electricity, distributed by sources as in Figure 1.[7]

FIGURE 1

Installed electricity capacity in Mexico (MW)



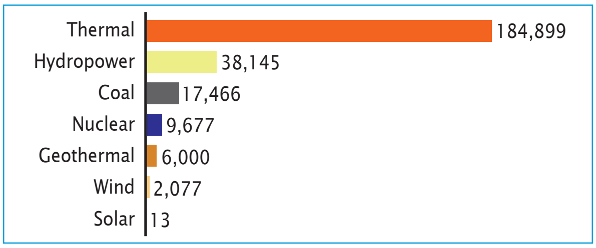
Source: Secretariat of Energy (SENER)[7]

The total electricity generation in 2014 was 258,277 GWh of electricity, distributed by sources as in Figure 2.[8]

The overall availability of base generation units was

FIGURE 2

Electricity generation in Mexico (GWh)



Source: SENER[8]

85.5 per cent in 2014. There was a margin of operating reserve of 17.0 per cent for the same year.[9] The overall energy mix in 2014 was 82.1 per cent from fossil fuels, including thermal, coal and nuclear. The renewable energy (RE) sources, including solar, wind, geothermal and hydropower amounted to 17.9 per cent of the total.

The national electrification rate in 2014 was 98.4 per cent; ranging from 99.6 per cent in the states of Aguascalientes and Coahuila, to 95.6 per cent in Oaxaca.[10] There are rural communities that remain without electric service, mainly due to their dispersion in mountainous areas, that could be served by RE and micro hydropower in particular.

In December 1992, the then existing Law of the Public Service of Electric Energy (LSPEE) was amended to allow private participation in generation of electricity for self-supply, cogeneration, external producers, small producers, import and export. The use of transmission networks was also permitted with a simplified low price scheme.

Private energy generators were not allowed by law to sell their production to the public, but exclusively to use it for self-supply, to sell to the Federal Commission of Electricity (CFE) or to export. The private generators were allowed to form a project specific enterprise including a pool of industrial, commercial and municipal end-users. These new entities were considered to fulfil the condition of self-supply.

There are 28 power plants belonging to the external producers' category that entered in operation in 2000 or after, with 12,851 MW. These include 23 combined cycle plants in different states and five wind power plants in Oaxaca. These plants generated 33.19 per cent of the total electricity in 2014, mostly from combined cycle.[11]

In 2013, a large process of radical reforms of the legal and institutional framework within energy sector started in Mexico. The reforms mainly focused on the oil and gas industry, but also included the electricity sector. On December 20, 2013, Articles 25, 27 and 28 of the Constitution were amended. Previously, only the nation had the right to generate, transmit, transform, distribute and supply electric energy for public service. The change enabled the State to control the planning and authority of the national electric system, as well as the public service of transmission and distribution of electricity. However, private companies are now allowed to participate in the remaining activities of the electric industry. Following the constitutional reform, 12 national laws were amended and nine additional laws were established. The changes entered into force on 11 August 2014.[12] The corresponding bylaws are being adjusted or promoted.

The roles of the main public institutions of the electricity sector were adjusted accordingly, including:

- Secretariat of Energy (SENER);
- Federal Commission of Electricity (CFE);
- Regulatory Commission of Energy (CRE);
- National Centre of Energy Control (CENACE);
- Secretariat of Environment and Natural Resources (SEMARNAT);
- National Water Commission (Conagua);
- National Commission for the Efficient Use of Energy (CONUEE).

As a consequence of the Energy Reform:

- The CFE and the National Oil and Gas Company (PEMEX) are now State Productive Enterprises that are required to compete with private companies.
- The CFE will be restructured and several affiliated and subsidiary entities will be separated from the core institution in 2016.
- The CFE and the PEMEX are allowed to form public-private associations.
- Private companies can generate and sell energy, capacity and associated products; excepting nuclear generation and supply to domestic users.
- There will be a new Wholesale Electricity Market (MEM) supervised by CENACE in January 2016.
- There will be a spot market with short-term transactions.
- There will be electricity auctions with long-term contracts.
- Qualified users of energy with a starting threshold of 2 MW in 2016 will be able to buy from the spot market, from energy vendors or directly from the generators.
- A new type of actor, the energy vendor companies, will be able to intermediate.
- Clean energy certificates will be issued and traded starting in 2018.
- There will be a minimum percentage of RE for generators to participate in MEM transactions.
- Private companies will be allowed to participate in the expansion and operation of the transmission and distribution networks.
- The price scheme for the electric transmission service will be changed to reduce subsidies.

The National Electric System is organized in nine regions. Seven of them form the National Interconnected System (SIN), which covers most of the territory with dense electric transmission and distribution networks. The Peninsula of Baja California has two regional networks. There are capacity restrictions in some nodes of the SIN that impose limitations or delays to the addition of new plants.

Since there is a margin of operating reserve, the shortage of electricity on a regional or seasonal scale normally does not occur. However, some outages of electric supply of short duration and limited extension may occur. The average interruption time per user in 2014 was 36.7 minutes.[13]

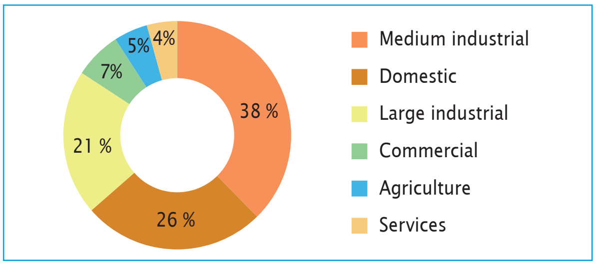
A transmission line of 103 km at 400 kV linking Mexico and Guatemala started operation on 22 April 2010. It had an initial capacity of 200 MW towards Guatemala and 70 MW in the opposite direction.[14] This strategic project allows energy transfers to the SIEPAC countries to serve the Regional Electric Market of Central America. Mexico is connected to Belize by a transmission line with capacity of 65 MW. To the north, Mexico has 11 interconnections with the States of Texas and California in the USA, with capacities ranging from 36 to 800 MW.

The total gross demand of energy in 2014 was estimated in 284,382 GWh. This included sales by the CFE, remote self-supply, exports, energy savings, reduction of energy losses, and the CFE's internal consumption. The expected annual rate of growth of demand of capacity in 2013-2028 is 4 per cent. This means that some 44,000 MW of additional capacity will be needed in the next 15 years, 80 per cent more than the present. The expected annual rate of growth of demand of energy from 2013-2028 is 3.8 per cent. It is foreseen that there will be an additional annual demand for energy of some 213,300 GWh in 15 years, which is 75 per cent more than the present.[15]

The total energy sales of CFE in 2014 were 208,015 GWh, distributed by user category as follows.[16]

FIGURE 3

Energy sales by user category



Source: SENER[16]

The monthly distribution of aggregated energy sales in 2014 had its peak of 19,463 GWh in August and its valley of 15,293 GWh in February. The total exports of energy in 2014 were 2,653 GWh, with 72 per cent to the USA and the rest to Guatemala and Belize. The total imports of energy in 2014 were 2,124 GWh, with 99.8 per cent from the USA and the rest from Guatemala.

Energy prices in the neighbouring countries are higher than they are in Mexico, mainly in Central America, where there are countries that suffer shortages.

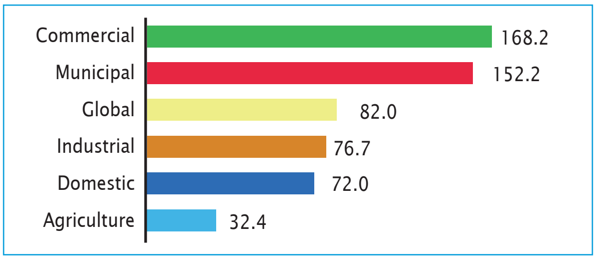
The strategic vision of CFE incorporates the following elements:

- Reduction of generation costs, mainly by decreasing the proportion of fuel oil plants in favour of natural gas and RE plants.
- Reduction of energy losses. The total losses in 2014 were estimated in 14 per cent, including physical (6 per cent) and commercial (8 per cent) losses.
- Reduction of electricity tariffs. The tariffs for industrial, commercial and domestic users started to decline by the end of 2014 as a result of the decreased use of costly fuel oil, the increased use of natural gas,the descent in international oil prices and the increment of hydropower generation.
- Implementation of the Energy Reform. The legal procedure to become a State Productive Enterprise was completed and CENACE was separated from the CFE on 28 August 2014.

The CFE has an electricity tariffs structure that considers: level of tension, category of use, region, season, required and used demand, required continuity, type of energy (base, intermediate and peak), day of the week, level of consumption and hour of consumption. This gives rise to more than 40 tariffs. The electricity tariffs are charged in Mexican Pesos and are indexed monthly. The following chart shows tariffs of five user categories and the global average from in 2015. The global tariff in August 2015 was US\$82.0/MWh.[17]

FIGURE 4

Electricity tariffs in 2015 (US\$/MWh)



Source: SENER[17]

The exchange rate considered in the previous charts was MXN16.32/USD on 6 August 2015. In general, the highest prices were in Baja California and Baja California Sur regions. The lowest prices are those of the north, north-east and north-west regions.

The tariffs of the CFE have been used as a reference in the negotiation of PPA within the self-supply scheme. Until now, this procedure has been attractive for private investors. However, there has been a decline in the tariffs since September 2014 of 15 per cent.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Mexico is up to 30 MW of electricity. The installed capacity of SHP was 470.2 MW in May 2015. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 4 per cent (Figure 5).

A hydroelectric generation facility is considered eligible for incentives aimed at RE projects when its capacity is lower than 30 MW, or when it has a Power Density of 10 W/m^2, which is the ratio of installed capacity to reservoir

FIGURE 5

SHP capacities (MW) in Mexico, 2013-2016

Sources: *WSHPDR 2013*,[26] SENER[17]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

surface.[25] This can be considered as the definition of SHP in Mexico.

There has never been a nationwide study of SHP potential and its value remains unknown. The CFE has conducted planning studies in the majority of river basins for several decades, looking for specific sites with expected production greater than 40 GWh/year. In 2012, its inventory had 585 such sites, including 73 plants presently in operation. The combined capacity of the remaining 512 sites was estimated in 41,132 MW, with a generation of 114,754 GWh/year, and an average plant factor of 32 per cent.[18]

In 1995, a global estimate close to 3,250 MW for the SHP potential of Mexico was published by CONAE, considering plants with capacity from 2 MW to 10 MW.[19] It was based on an inference from data of 18 countries. Later on, the author stressed the urgent need to conduct a real assessment of national SHP potential.[20] Nevertheless, many official and academic documents continued until present to cite the figure of 3,250 MW as a fact. There have been several official studies of SHP potential assessment in natural streams of some river basins that cover a very small portion of the national territory. These studies have a widely varying degree of hydrological and topographical precision. In the low end of precision, there is a pioneering study requested by CONAE in 1995 of six watersheds on the Gulf of Mexico coast, covering 26,376 km^2, where a total of 100 SHP sites were identified using simplified techniques and data.[19] In the high end of precision, there are studies requested by CFE in 2007 of three watersheds, covering 29,259 km^2, where a total of 3,118 micro, mini and SHP sites were identified using advanced techniques. This included 110 SHP sites.[21]

Facing the need to estimate the small-scale hydropower potential under 30 MW as input for planning purposes, SENER has published a total probable SHP potential of 2,629 MW.[22] This value is combined capacity of 469 sites picked from the 512 in the inventory of CFE, after raising the plant factor to 100 per cent and reducing the height of the dams. Another estimate using a plant factor of 80 per cent yielded a total possible hydropower potential of 6,300 MW. These estimates are largely uncertain.

Taking into account the rugged relief and heavy rain pattern in vast river basins of Mexico that have yet to be studied, it is logical to assume with good confidence that once a systematic and exhaustive assessment of SHP potential is carried out, thousands of feasible sites will appear instead of hundreds. The total capacity will also be counted in the order of tens of thousands MW.

In terms of installed capacity, in May 2015, hydropower amounted to 89.5 per cent of the total amount of RE. In terms of annual generation, in 2014 it was 82.5 per cent of the total amount of RE.[7,8] The total capacity of 31 SHP plants in operation belonging to CFE is 284.7 MW. Their mean annual generation is 1,084 GWh. The average plant factor is 46.3 per cent. The total capacity of 17 SHP plants in operation belonging to private owners is 185.5 MW. Their mean annual generation is 748 GWh. The average plant factor is 37.6 per cent. CRE has issued 79 hydropower generation permits since 1992, when the LSPEE was amended.[23] The combined capacity is 1,411.3 MW, ranging from 0.4 MW to 165 MW. The estimated annual generation is 5,815 GWh, with an average plant factor of 57.5 per cent. The number of hydropower plants with permits and the total capacity by status are as follows:

- 17 plants are in operation at 195.4 MW;
- 27 plants are in construction at 736.1 MW;
- 34 plants are to start construction at 459.8 MW;
- One plant is inactive at 20 MW.

Developers are currently facing uncertainty as to how and when the new institutional and regulatory framework will take effect.

The Convention No. 169 of the International Labor Organization (ILO), ratified by Mexico in 1991, sets the obligation to obtain on good faith the free, prior and informed consent from the indigenous and tribal peoples about new projects in their territory. The Law of the Electric Industry reinforces it in Art. 119. Systematic opponents to hydropower projects are prone to misuse this obligation by attempting to manipulate the inhabitants of distant communities.

Legislation on small hydropower

The licensing process includes the following main procedures:

- Legal incorporation of the company (15 days) obtained by the developer.
- Environmental Impact Assessment (EIA) authorisation (20 or 60 days) issued by SEMARNAT. Three options with increasing levels of complexity, depending on whether the project includes a preventive report, a particular or a regional EIA.
- Water authorization (60 days, for a period of 5-50 years) issued by Conagua, which grants the concession to use surface water. There are exemptions if the project is eligible as a RE project permit to use federal zone and a permit to build hydraulic infrastructure.

- Feasibility studies by the CFE, consisting of a study on grid connection (30 days) and a feasibility study on transmission (20 days). Contracts issued by the CFE also need to be obtained, including a contract on grid connection (90 days), a contract to buy/sell RE to CFE, an agreement of electric backup and an agreement of transmission.
- Permits for electric energy generation, issued by the CRE (20 to 50 days).
- Municipal Permits for construction, issued by the municipal governments involved.

Renewable energy policy

The National Strategy for Energy Transition and Sustainable Use of Energy sets objectives, lines of action and goals for 2024 for the Federal Government to promote the greater use of RE and clean technologies. From 1992 until the Energy Reform, there were a number of incentives for RE including the following:

- Zero import duties for equipment that prevent pollution and for research and technological development;
- Accelerated assets depreciation for infrastructure projects that use RE sources;
- Contract of interconnection for intermittent RE sources with favourable provisions.

In 2008, the Law for the Use of Renewable Energies and the Financing of the Energy Sector Transition (LAFERTE) was issued, which included economic, financial, fiscal, administrative, electric connection and technological incentives for RE projects.[24] Likewise, in 2008, the Law for the Sustainable Use of Energy (LASE) was issued. This law also provides the National Programme for Sustainable Energy (PRONASE) and the National Commission for the Efficient Energy Use (CONUEE). SENER is legally bound since 2008 to assess, update and publish the national inventory of potential of RE.

The new Law of Energy Transition (LTE),[25] which entered in force on 24 December 2015, to promote RE in the context of the Energy Reform replaced the two laws mentioned above, LAFERTE and LASE. The main goals of LTE are the following:

- Set goals for the clean energy portion in the generation matrix of 25 per cent in 2018, 30 per cent in 2021, and 35 per cent in 2024. The same proportion was 25 per cent in 2014.
- Provide instruments for the distributed generation and sale of energy by any person or enterprise.
- Provide for the strengthening and expansion of the transmission and distribution networks through the Programme of Smart Electric Grids.
- Strengthen the institutions charged with promoting energy efficiency.
- Create the National Programme of Sustainable Management of Energy to achieve energy efficiency goals.

SENER and Conacyt have allocated funds to four Energy Innovation Centres focused on wind, solar, geothermal and ocean RE sources. With regard to the emissions of 2000, the General Climate Change Law has set the indicative goal of reducing CO_2 equivalent emissions by 30 per cent in 2020 and by 50 per cent in 2050. On 27 March 2015, Mexico presented before the United Nations Framework Convention on Climate Change (UNFCC) its goals and commitments to reduce GHG by 22 per cent in 2030, compared to the levels of 2013.

Barriers to small hydropower development

Mexico is a land of opportunity for RE development. The vastness of its hydropower potential remains to be assessed and harnessed. There is an enabling regulatory framework and the Energy Reform tends to improve it with the new Wholesale Energy Market unfolding. However, there are barriers to overcome so that the country can attain in the next decades its goals of a cleaner energy matrix amid an ever-growing demand of electricity. In the next 15 years, an additional annual demand for energy of 75 per cent more than the present is expected. A large portion of its supply could come from hydropower and other renewable sources. These details are detailed as follows:

Renewable energy sector:

- Clear preference by policy makers to promote the expansion of the oil and gas industries over RE sources, considering the amount and investments and political support.
- Clear preference by policy makers for other RE over SHP, mainly wind and solar power.

Technological:

- Absence of a national hydropower potential inventory that is detailed and reliable.
- Hydrological uncertainty due to lack of adequate meteorological and hydrometric series.
- Studies tend to focus on local projects, rather than on entire river basins to systematically assess all feasible projects.
- Absence of prospective studies of water resources scenarios by watersheds to assess the impact on SHP projects in the long term.
- Technical deficiencies in SHP project formulation, due to rudimentary methods applied in the early phases of prospection and prefeasibility studies resulting in low success rate.
- Insufficient technical documentation of SHP projects, which adds to the difficulty and duration in the promotion phase.
- Limited local manufacturers of turbines.

Social:

- Legitimate social and community concerns regarding hydropower projects, often based on lack of education and objective information.
- Ideological and political opposition induced against

hydropower projects, private participation and foreign investments.

- Disproportionate expectations of local communities regarding compensations to remedy regional underdevelopment and lack of services.
- Delays or blockage of projects due to environmental and social opposition.
- Regional insecurity and delinquency.

Regulatory:

- Requirement to complete elaborate, costly feasibility studies, prior to having the assurance to obtain all the permits for the project.
- Complex and multiple licensing procedures with federal, state and municipal authorities, due to lack of a one-stop/single window scheme.
- Restrictions to issue water use permits for generation in river basins with extraction regulation or ban, even if hydropower is non-consumptive.
- High restrictions on projects proposed in protected areas, without objective balance of positive and negative impacts.
- Difficulty to license SHP projects in existing hydraulic urban and irrigation infrastructure.
- Requirement to connect to the electric grid in higher tensions.
- Exposure to risk of issuance of new concessions for different water uses or diversions upstream of the hydropower project.
- Delays in the consultation to get the consent of indigenous population due to lack of personnel and funds in the involved public institutions.
- Period from one to three years for licensing processes.

Legal:

- Risk of legal project interruption due to social or environmental pressures.
- Risk of legal challenge by another developer for a site that is under prospection or licensing process.
- Long period of contract preparation for structuring projects.

Economic:

- Limited coverage and maintenance of roads in areas with high hydropower potential, requiring major investment in access roads.
- Limited coverage and capacity of electric grid in some areas with high hydropower potential, requiring major investment in interconnection lines.
- Generation and transmission electric networks that have privileged concentrated over distributed generation.
- Charges or duties for the volume of water used to generate energy, rather than for the energy produced.
- Inadequate or incomplete assessment of SHP project flows of costs and benefits.
- Difficulty of valuation of positive externalities of RE sources.

Commercial:

- Saturation of the consumer market for self-supply.
- Low credit rating of prospective energy consumers.
- Low prices of energy delivered to the national electric system.
- Risk of gradual or sharp decline in energy prices due to energy bids.
- Difficulty to access mechanisms of payment for GHG emissions reduction.

Financial:

- Lack of financing options for the prospection and prefeasibility phases.
- Limited funds made available by commercial banks in the country for SHP projects.
- Terms of commercial credit are not conducive to project implementation.
- Requirement to augment the ratio of equity capital to debt.
- Difficulty to access equity capital for some developers.
- Requirement to structure syndicated loans for larger projects.
- Difficulty of access to mezzanine funds, clearly subordinated to principal debt.
- Condition to disburse equity capital prior to using debt capital.
- High requirements of banks to assess the specific track record and financial solvency of the project developers.
- High requirements of financial guarantees, beyond the project expected cash flows, including:
  - Long term power delivery agreements;
  - High credit rating of energy consumer partners;
  - Construction and supervision contracts with highly ranked and costly firms (EPC);
  - Operation and maintenance contracts during the loan term;
  - Requirement of opinions from independent experts.
- Difficulty in accessing mechanisms of partial guarantees of the loan.
- Difficulty in accessing mechanisms of guarantees against cost overruns of projects.

2.2.7 Nicaragua

Marcis Galauska, International Center of Small Hydro Power

Key facts

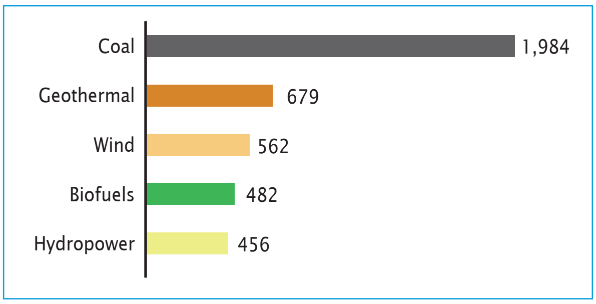
Population	5,907,881[1]
Area	130,370 km^2 [1]
Climate	The climate is tropical in the lowlands and cooler in the highlands, with two distinct seasons, wet and dry. The wet season lasts from mid-May to November, with May and October being the wettest. Temperatures in this season usually range from 27°C to 32°C. The dry season lasts from December to April, with April being the hottest and driest month. Temperatures during the dry season usually range from 30°C to 35°C but the weather can be very dry and windy.[2]
Topography	The Caribbean coast consists of low, flat, wet, tropical forest, extending into the pine savannas 80-160 km inland. The coastal lowland rises to a plateau covering about one-third of the total area. This plateau is broken by mountain ranges extending eastward from the main cordillera to within 64-80 km of the Caribbean coast. The mountainous central area forms a triangular wedge pointed south-east, rising at its highest to some 2,000 m. The highest peak is Pico Mogotón at 2,106 m. The plains and lake region, in a long, narrow structural depression running north-west to south-east along the isthmus, contains a belt of volcanoes rising to 1,500 m and extends from the Gulf of Fonseca to Lake Nicaragua.[3]
Rain pattern	The average annual rainfall along the Caribbean coast reaches 2,540-6,350 mm as a result of easterly trade winds blowing in from the Caribbean; the highlands also have heavy rainfall. Managua receives 1,140 mm while the Pacific coast averages over 1,020 mm a year.[4]
General dissipation of rivers and other water sources	General dissipation of rivers and other water sources All of the major rivers run into the Caribbean. The Rio Grande, along with its tributaries, is the most extensive river system, while the Escondido provides a major transportation route between the Pacific and Caribbean coasts. The Coco runs along the border with Honduras and is the country's longest river at 680 km. The San Juan begins in Lake Nicaragua and forms part of the border with Costa Rica.[5]

Electricity sector overview

In 2013, electricity generation in Nicaragua was 4,163 GWh. An additional 52 GWh of electricity was imported and 16 GWh was exported, making overall domestic supply 4,199 GWh. 1,984 GWh was generated by coal, 679 GWh from geothermal, 562 GWh from wind, 482 GWh from biofuels, and 456 GWh from hydro sources (Figures 1 and 2).[6]

FIGURE 1

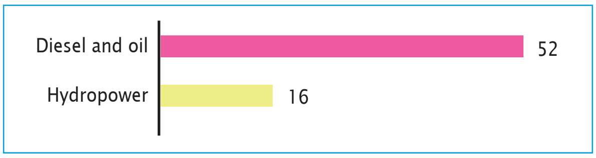
Electricity generation in Nicaragua (GWh)



Source: IEA[6]

FIGURE 2

Electricity import/export in Nicaragua (GWh)



Source: IEA[6]

The total installed capacity was 1,275 MW. National electricity is subdivided into two concession areas, covering only the western part of the country. More than half of the country on the Caribbean and Atlantic coasts remains outside of these concession areas.[7] The overall electrification rate in Nicaragua is approximately 77.9 per cent, although the rural electrification rate is much lower.[15]

Electricity generation can be contracted via tenders organized by distributors or through bilateral contracts between generators and distributors and/or large consumers. The Instituto Nicaragüense de Energía (Nicaraguan Energy Institute, or INE) regulates the electricity sector, where transmission and distribution are subject to regulated tariffs and generators can compete freely in the market. The Comité Nacional de Despacho de Carga (CNDC) is the electricity market operator, while the Ministry of Energy and Mines (MEM) oversees energy policy and planning.[8]

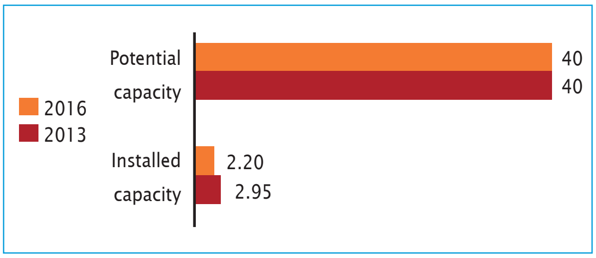
The National Development Plan in 2013 called for 94 per cent of the country's electricity to be sourced from RE by 2017. The plan was ambitious and the country will not reach this goal by 2017. However, Nicaragua has been achieving many of its energy goals, specifically with wind farms and geothermal plants. Such achievements have already allowed it to reach its current share of nearly 75% of the gross domestic primary energy supply, and about 50 per cent of the total electricity supply, according to the INE.[16] As a result, the government has since adjusted its aim from 94 per cent in 2017 to 91 per cent in 2027.[16] A key part of the plan has been the 82 MW San Jacinto project, a massive 3,965 ha geothermal power plant built on the San Jacinto-Tizate geothermal area,[10] widely considered to be one of the most productive volcanic reservoirs in Latin America. The plant is an essential component for the country's continued infrastructure development, and in 2013 it generated revenue of US$46.2 million and 424,000 MW of net power.[9]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Nicaragua is up to 10 MW. The installed capacity of SHP is 2.2 MW while the potential is estimated to be 40 MW, indicating that approximately 5 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has decreased while the estimated potential has not changed (Figure 3).

FIGURE 3

SHP capacities 2013-2016 in Nicaragua (MW)



Sources: *WSHPDR 2013*,[12] IJHD[11]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The total installed capacity of SHP, approximately 2.2 MW, produces 0.0245 GWh/year. A further 142 kW of SHP is under construction, with another 2.7 MW planned for the next ten years. The total amount of SHP under construction is expected to generate 49 MWh/year and planned SHP is estimated to produce 9.4 MWh/year.

There are 18 SHP plants currently in operation. These are Samaria (7 kW), Aguas Rojas (5 kW), Las Piedrecitas (7kW), Las Brisas (5 kW), Los Milagros (10 kW), Kasquita (25 kW), Castillo Sur (24 kW), Kuskawas (50 kW), Ocote Tuma (30 kW), San Luis (50 kW), Campo Real (12 kW), San Vincente (42 kW), Malacotoya (13 kW), Bilam Pi (340 kW), Rio Bravo (180 kW), El Bote (900 kW), El Naranjo (240 kW) and Salto Negro (220 kW).

There are seven small hydro projects under construction. These are El Roblar (13 kW), La Laguna (23 kW), Valle los Meza (32 kW), Cano Los Martinez (20 kW), San Antonio de Yaro (14 kW), Dipina Central (25 kW) and El Zompopo (15 kW).

There are 10 planned small hydro projects. These are El Corozo (300 kW), El Golfo (230 kW), casa Quemada (425 kW), Salto El Humo (200 kW), Salto Labu (210 kW), Salto Pataka (120 kW), El Hormiguero (250 kW), Salto Putunka (600 kW), Tunky Ditch (160 kW) and Ayapal (200 kW).[11]

Legislation on small hydropower

Most of the projects are financed by private investors or international organizations (European Investment Bank, Inter-American Investment Bank etc.). The Nicaraguan Government provides its investors with tax based incentives such as income tax and import duty tariffs to support the implementation of clean energy projects. Furthermore, local micro finance institutions portray a robust system with 10 organisations providing green finance at an average cost of 1.5-28 per cent.

The Nicaraguan Government has declared hydropower development to be an important part of its energy policy. A favorable legal framework and an attractive incentive structure have been established for hydropower plants with capacities below 5 MW. The necessary environmental permits are obtained from the Ministerio del Ambiente y los Recursos Naturales, generation of licences from Instituto Nicaragüense de Energía (INE), and water concessions from the Ministerio de Fomento, Industria y Comercio (MIFIC).[14]

Law 476 for the Promotion of Hydroelectric Sub sector stipulates that hydropower schemes below 1 MW do not need a water concession. Instead producers will get a permit for 15 years. For schemes with capacities of 1-5 MW, a simplified procedure applies to obtain a water concession from MIFIC. Law 217 General Law of the Protection of Environment and the Natural Resources stipulates that projects with capacities below 5 MW do not need an environmental impact assessment.[14]

Renewable energy policy

The principal legislation governing RE generation in the country is Law 532 for the Promotion of Electric Generation from Renewable Sources. It promotes the following:

- Full exemption from taxes on the sale of carbon bonds;
- Exemption from all taxes that might exist for the exploitation of natural resources for a maximum of five years after the start of operations;
- Exemption from payment of customs duties and value added tax (VAT) on imports, machinery, equipment, and all materials intended solely for the pre-investment (and construction of) the sub-transmission line for the national interconnection system.[13]

In addition to the above, a high-level government entity for the country's energy sector was created in 2007, the Ministry of Energy and Mines (MEM). Its mandate is to allocate resources to resolve the energy crisis in the country, and create an energy sector consistent with the country's long-term sustainability plan. One of MEM's main obligations is to oversee the formulation, coordination and implementation of the strategic plan, as well as the public policies, covering the energy sector. MEM also oversees the operation and administration of companies operating in the RE sector. There is a great potential for development of RE, approximately 2,000 MW for hydro, 1,500 MW for geothermal, 800 MW for wind and 200 MW for biomass, the goal is to reach 91 per cent of electricity generation from renewable resources by 2027.

Barriers to small hydropower development

- Difficulty in accessing finance because of the high initial cost of projects. Commercial finance is needed for the long term, but in general, financial assistance is short-term and hence shows high interest rates.
- Requirements and costs for permits are the same for large and small projects. The cost per MW for small projects is very high and the concession process is very slow, often lasting several years.
- Power purchase agreements are too short to motivate SHP project development. Therefore, it is difficult to take long-term investment decisions.
- The approved fiscal incentives for hydropower projects do not yet create a level playing field for hydropower development in general compared to thermal projects, since the latter continue to be highly subsidized.[12]

2.2.8 Panama

José Fábrega, Alexis Baúles and Denise Delvalle, Universidad Tecnológica de Panamá

Key facts

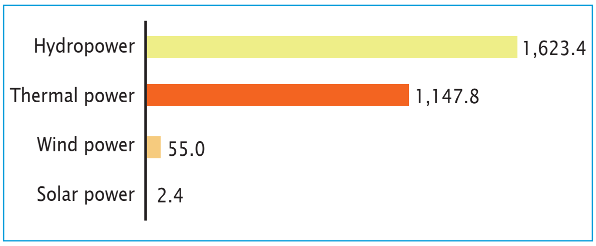
Population	3,657,024[1]
Area	75,420 km[2]
Climate	It has a tropical climate with two seasons, dry and rainy, with variations depending on the region and the altitude. Winter is the wet season (May to November) while summer is the dry season (December to April, with March and April normally being the warmest months). The temperatures on the coast regularly reach 35°C, but the temperature drops 1°C for every 150 m.
Topography	Panama has rugged mountains to the west and towards the Caribbean Sea and rolling hills along with large plains to the Pacific Coast. The lowlands in Panama cover around 70 per cent of the country. The highest point in Panama is the Volcán Barú, which rises to 3,475 m.
Rain pattern	From 1971 to 2002, Panama had a yearly average precipitation of 2,924 mm.[2] The Pacific region shows a wet season pattern from May to November. For the Atlantic region, precipitation is continuous throughout the year.[3]
General dissipation of rivers and other water sources	There are around 500 rivers in Panama in 52 watersheds, with 70 per cent of rivers running to the Pacific side (longer streams) and 30 per cent to the Atlantic side.[4]

Electricity sector overview

The energy generated in 2014 was approximately 9,256 GWh, from which only 4.7 per cent came from renewable sources.[5] The consumption of electricity in 2014 was 7,822 GWh. Panama exports its energy surplus to neighbouring countries like Colombia. Thus, the government aims to make Panama an energy hub in Latin America.[6]

FIGURE 1

Installed electricity capacity in Panama (MW)



Source: SNE-ETESA[5]

Electricity generation in Panama comes mainly from hydropower, thermal generation and renewable energy sources like wind and solar power. The installed capacity in Panama by the end of 2014 was 2,828.6 MW, which was 6.1 per cent more than in 2012. Hydropower represents 1,623.4 MW (57.4 per cent) and thermal represents 1,147.8 MW (40.6 per cent). Furthermore, 55.0 MW (1.9 per cent) came from wind farms and 2.4 MW (0.08 per cent) from solar energy (Figure 1).[5]

It is worth mentioning the role of the Panama Canal Authority. The Panama Canal Authority is the biggest independent producer (auto generator) in Panama, with an installed capacity of 258.6 MW (71.8 per cent comes from thermal plants and 28.2 per cent from mini and small hydropower (SHP)).[7] The main objective of the Panama Canal Authority is to assure the performance of the canal. Even though there is a favourable legal framework for the development of SHP plants, a local financial framework supporting the investment of SHP plants is still lacking.

The National Department of Energy, created by Law 43 on 23 April 2011, is in charge of the energy sector.[9] The Rural Electrification Office (Oficina de Electrification Rural, or OER) is responsible for providing energy in the rural and isolated areas that are not connected to the national grid. The OER has a goal to increase the electrification for rural areas by using photovoltaic energy and building electricity grids for short distances (10 km). From November 2013 to October 2014, up to 109 projects were completed in the provinces of Colon, Darien, Coclé, Bocas del Toro and Indigenous territories. Approximately, 25,000 inhabitants received access to electricity.[10] The OER is supervised and budgeted by the Ministry of the Presidency. However, all project ideas have to be proposed by rural communities in order to be included in their planning.

The energy sector is regulated by Law No 6 introduced on 3 February 1997 (and its later amendments) as well as by Decree Law 22 of 1998.[9,11,12,13] The transmission of energy is carried out almost entirely by the Empresa de Transmision Electrica S.A. (ETESA). Currently, the electricity grid of Panama consists of two main transmission lines. There is a transmission systems modernization and expansion plan financed by the Latin-American Development Bank for the period of 2014-2017. The plan expects to carry out the following by the end of 2015:

- The modernization of the electricity transmission system, through increasing the capacity of transmission of electricity in the National System of Interconnection;
- Extend the coverage of the network;
- Improve the quality of the service.[6]

The construction of a third transmission line is needed and it is foreseen to become part of the national grid in a few years.[14]

The total electricity consumption considering all sectors (private, commercial, governmental, industrial and public electrification facilities) in Panama was 7,401 MWh in 2014. This number represents a per capita consumption of 1,735 kWh and is double the average consumption rate in Central America (848 kWh per person).[15] According to a statement issued in 2014 by the Department of Energy, the demand of electricity is going to increase approximately 4.8-7.4 per cent for the next 15 years. In order to alleviate the energy shortage of 300 MW, several thermoelectric power plants have been contracted in 2015.[16]

In Central America, the Central American Electric Interconnection System has been set up in order to create an integrated electric market within the six countries of the region: El Salvador, Guatemala, Honduras, Costa Rica, Nicaragua and Panama.[17] For instance, in 2012, an interconnection was planned with Colombia. The planned line has an extension of 614 km (including an underwater line of 55 km, with 44 km in Panamanian territory). However, this project was stopped for two years after the President of Panama disapproved of the costs. In 2014, however, the President of Panama, along with his Colombian counterpart, agreed to restart the project and projected a completion date for 2018.[27] After the privatization of the public electricity service in 1998, the ETESA was charged with dispatching and transporting electric energy in an efficient, safe and reliable way—through adequate planning for the expansion, the construction of new amplifications and the reinforcement of the transmission grid.[18] The remuneration for the services carried out by the ETESA is regulated by Law 6 of 1997.[11]

Small hydropower sector overview and potential

Although the Latin American Energy Organization's (OLADE) definition of SHP for Latin America is up to 5 MW,[19] the legal framework in Panama considers plants up to 10 and even 20 MW.[20]

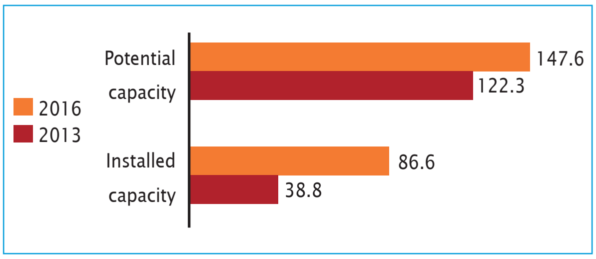
OLADE's definitions on SHP is as follows:[19]

- Small hydropower: 500-5,000 KW.
- Mini hydropower: 50-500 KW.
- Micro hydropower: up to 50 KW

Figure 2 shows the increase in SHP potential and installed capacity from 2013 to 2016 (as of January). Potential capacity is defined as concessions granted for SHP plants.

FIGURE 2

SHP capacities 2013-2016 in Panama (MW)



Sources: ASEP,[21] *WSHDR 2013*[22]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Since 1970, the Government of Panama has shown interest in the development of SHP plants. The government, in collaboration with the US Agency for International Development carried out a study in the country and identified 40 potential SHP sites. In the framework of these studies, the following micro hydropower plants were built: La Tronosa (60 kW), La Pintada (30 kW), Pueblo Nuevo (50), Buenos Aires (10), Entradero de Tijeras (50 kW) and El Cedro (35 kW). These micro hydropower plants were built with the support of the Government and the communities.[23]

In Panama, a self-generation producer is defined as an entity producing and consuming electricity in the same place in order to attend its own needs. These kinds of energy producers do not sell or transport energy to third parties. However, they can sell the energy surplus to other energy agents.[7]

Renewable energy policy

The starting point for the promotion of renewable energies is included in Chapter II, Title VIII of the Law 6 of 1997.[11] Renewable energy sources are defined in this law as geothermal, wind power, solar energy, biomass and hydropower. The high prices and the high levels of energy consumption led to the promulgation of the Law 44 of April 2011;[18] this law aims to promote mostly wind power and the diversity in the renewable energy sources. The application of the model Long-Range Energy Alternative Planning is used to determine the possible scenarios of combination in between energies, i.e. hybrid systems. It is a way for developing scenarios created by Shwartz in the context of economic and energy models.[24]

According to the National Energy Plan,[25] incentives are being applied in order to comply with the Kyoto Protocol. However, these incentives might need to be adapted to the new agreements made in the 2015 COP 21 held in Paris.[26] The Panamanian Government and private investors are working on developing SHP, wind farms, solar energy, and biomass generation.

Small hydropower legislation

The government established a legal framework in 2004 by enacting Law 45, with incentives for hydropower generation and other renewable energy sources with an extended scope for the SHP definition (up to 20 MW).[20] Law 45 provides incentives for small and mini hydropower plants: SHP plants up to 10 MW are not charged for selling energy directly or indirectly, small projects of 10-20 MW receive exemptions for the first delivered 10 MW for 10 years, there are fiscal exemptions for importing equipment, machinery, materials and others and there are fiscal incentives for projects up to 10 MW and with up to 25 per cent of CO_2 emissions per year.

Barriers to the small hydropower development

Although there is a favourable legal framework granting fiscal incentives in order to develop SHP plants, the SHP sector development is not significant. The most important barrier is the lack of a solid financial framework in order to support the investment in SHP plants. It is also worth noting that the OER does not include the development of SHP plants in its future plans.

2.3 South America

Cleber Romao Grisi, WHITEnergy Bolivia

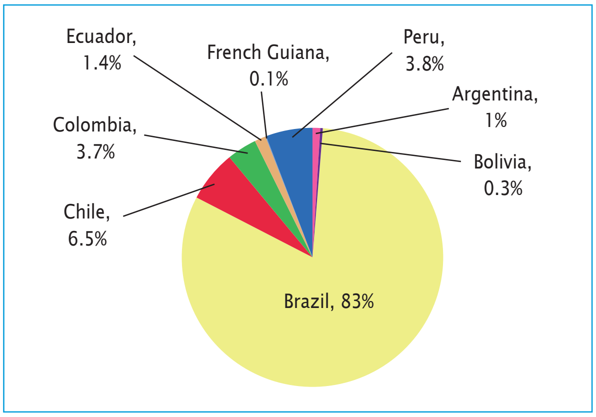
Introduction to the region

South America is the fourth largest subcontinent on Earth with a total land area of approximately 17.8 million km^2. It is bordered by Central America and the Caribbean Sea to the northwest, the Atlantic Ocean to the east and north and the Pacific Ocean to the west. The South America region comprises 12 sovereign countries: Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, Guyana, Paraguay, Peru, Suriname, Uruguay and Venezuela, as well as several dependent major territories: French Guiana administrated by France, the Falkland Islands and the South Georgia and South Sandwich Islands under the British Government. This report covers 10 countries and one territory, of which eight have an installed capacity of small hydropower (SHP), with Brazil having 83 per cent of the regional total (Figure 1). This report also covers Paraguay and Guyana, which were not included in the *World Small Hydropower Development Report (WSHPDR) 2013*.[1,3,9]

South America can be divided into three physical regions: river basins, coastal plains, as well as mountains and highlands. Coastal plains and mountains and highlands generally run in a north-south direction, while highlands and river basins generally run in an east-west direction. The western part is dominated by the Andes mountains, where temperatures fall below 0°C, and the Pacific coast, where rainfall can be as low as 1 mm per year (Atacama Desert). The eastern region is ruled by tropical rainforests and vast grasslands, where the average temperature is about 30°C and rainfall can exceed 5,000 mm a year.[6]

FIGURE 1

Share of regional installed capacity of SHP by country



Source: *WSHPDR 2016*[10]

There are approximately 418.5 million inhabitants; most of this population lives near the continent's western and eastern coasts, while the interior and the far south are sparsely populated.[2] Approximately 83 per cent of the total population lives in the urban areas.[7] In South America, almost 87 per cent of the rural population has electricity access. The urban electrification rate is about 98 per cent.[5]

Electricity is produced from different sources where the dominant technologies are hydropower and thermal.

TABLE 1

Overview of countries* in South America (+ % change from 2013)

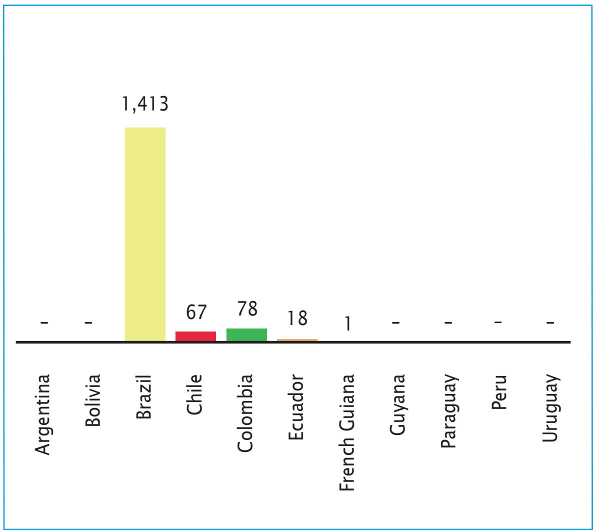
Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Argentina	42.6 (+5%)	8.2 (+0.2pp)	95 (-2.2pp)	37.6 (+11%)	131,205 (+2%)	10,700 (+6%)	40,663 (+1.8%)
Bolivia	10.0 (+1%)	31.5 (-1.5pp)	87 (+9.5pp)	1.61 (+11%)	7,836 (+28%)	477 (0%)	2,233 (-42%)
Brazil	202.7 (+6%)	14.3 (+1.3pp)	99.7 (+0.7pp)	142 (+21%)	624,300 (+17%)	92,159 (+12%)	407,200 (+1%)
Chile	18.0 (+5%)	10.5 (-0.5pp)	99.6 (+1.1pp)	19 (+8%)	69,897 (+11%)	6,410 (+7%)	23,871 (0%)
Colombia	48.3 (+4%)	23.6 (-1.4pp)	98 (+4.4pp)	15.5 (+7.5%)	N/A	10,919 (+12%)	38,714 (0%)
Ecuador	16.2 (+12%)	36.3 (+3.6pp)	97.2 (+4.1pp)	5.10 (0%)	23,258 (+13%)	2,237 (0%)	11,048 (+20%)
French Guiana	0.24 (+4%)	15.6 (-8.4pp)	N/A	0.29 (0%)	N/A	119 (-7%)	N/A
Guyana	0.76	71.4	79.5	0.18	771	0	0
Paraguay	6.55	40.3	99	8.83	55,582	8,834	55,276
Peru	31.15 (+7%)	21.4 (-1.6pp)	90.3 (+4.6pp)	12.25 (+30%)	48,066 (+209%)	4,166 (-5%)	23,300 (-4%)
Uruguay	3.40 (+1%)	4.7 (-3.3pp)	99 (+0.7pp)	3.12 (+16%)	10,515 (6.3%)	1,538 (0%)	3,125 (-61%)
Total	**379.9 (+8%)**	—	—	**245.5 (+22%)**	**971,430 (+15%)**	**137,559 (+18%)**	**605,430 (+12%)**

Source: *WSHPDR 2013*,[9] *WSHPDR 2016*,[10] Geohive[7]

Other sources include nuclear, wind and biomass. Installed capacity and energy production have increased in all South American countries since 2013. Five countries have increased their share of SHP resources (Figure 2).

FIGURE 2

Net change in installed capacity of SHP (MW) for South America, 2013-2016



Sources: *WSHPDR 2016*,[10] *WSHPDR 2013*[9]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

SHP definition

The definition of SHP varies across the countries in South America. In most cases, there are no limits for categorizing small, micro and pico hydropower. In some countries, SHP remains undefined (Table 2).

TABLE 2

Classification of SHP in South America

Country	Small (MW)	Mini (MW)	Micro (kW)	Pico (kW)
Argentina	≤ 3	50 to < 500	5 to < 50	—
Bolivia	0.5 to < 30	—	< 500	—
Brazil	1 to < 30	—	—	—
Chile	< 20	—	< 300	—
Colombia	0 to < 10	—	—	—
Ecuador	10 to < 20	—	—	—
French Guiana	—	—	—	—
Guyana	≤ 5	—	—	—
Paraguay	—	—	—	—
Peru	≤ 2	—	—	—
Uruguay	< 50	100-1,000	< 100	< 5

Source: *WSHPDR 2016*[10]

Regional overview and renewable energy policy

South America hosts the Amazon, Orinoco, and Paraguay/Paraná River basins, covering almost 7 million km², 948,000 km² and 2.8 million km², respectively.[6] These watersheds make this continent attractive and suitable for hydroelectric development of varying capacities.

The total hydropower installed capacity in South America, including large, medium and small facilities, is about 103 GW. Hydroelectric production has increased since 2013 for all countries in South America, except in Bolivia where thermal (natural gas) energy has replaced hydropower production.

Countries in South America started to develop SHP projects to feed small towns or the national grids since 1970. However, project development is slow due to the higher costs compared to large or medium scale hydropower schemes, the lack of appropriate regulations related to taxes, tariffs, subsidies and concessions, environmental permits and due to social acceptance.[9,10] However, since 2013, potential capacity for SHP in South America has increased by 14 per cent and the installed capacity has increased by 31 per cent. Table 3 gives an overview of SHP in South America.

TABLE 3

SHP in South America (+ % change from 2013)

Country	Potential (MW)	Planned (MW)	Installed capacity (MW)	Annual generation (GWh)
Argentina	430 (0 %)	30	66 (0 %)	N/A
Bolivia	50	50	21.3 (0 %)	N/A
Brazil	25,000 (+11 %)	429	5,518.5 (+34 %)	26,400
Chile	17,000 (+57 %)	423	435 (+18 %)	N/A
Colombia	25,000 (0 %)	N/A	250 (+46 %)	N/A
Ecuador	383 (+29 %)	49	94.92 (+24 %)	474.13
French Guiana	N/A	7	6.3 (+15 %)	N/A
Guyana	24.17	N/A	0	0
Paraguay	N/A	0	0	0
Peru	1,600 (-)	N/A	391 (+11 %)	N/A
Uruguay	232 (+111 %)	N/A	0	N/A
Total	63,457 (+99 %)	988	6,783 (+291%)	

Source: *WSHPDR 2013*,[9] *WSHPDR 2016*[10]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.

Most countries in South America, including Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, etc., have renewable energy policies to encourage and provide benefits for developing renewable energy projects that comprise SHP schemes. Some benefits to SHP projects are the following:

- Exemption or reduction of taxes for importing equipment and construction;
- Purchase power agreements to secure the energy purchase price in a mid or long term agreement allow investors to pay the generation costs and to receive an acceptable investment return rate;
- Favourable conditions to meet government, authorities or any other regulatory institution requirements to acquire the necessary permissions to develop the project;
- Financing with suitable conditions to develop SHP projects.

Barriers to small hydropower development

As mentioned above, South America has enormous hydro potential to develop large, medium and SHP projects. However, certain technical, regulatory and policy issues may interfere with the implementation of SHP projects. A few of these issues are:

- Lack of or poor SHP project framework, rules, other conditions and incentives for their development. There are political constraints and structural limitations within the governmental agencies that are responsible to enforce policies or regulations to provide the framework for the development of SHP projects (i.e. Argentina, Bolivia, Guyana).
- Financial resource constraints due to limited availability of local finance institutions or local financial policies.
- Social risks related to the local people's perception and lack of information regarding the impacts and benefits of SHP projects. Insufficient regulatory frameworks that may lead to project cancellation due to a lack of social acceptance.
- High investment cost to develop, construct, and operate SHP schemes, compared to large or medium scale hydro projects.
- Poor quality of hydrological, climate and statistical data, especially for remote areas far from the main cities where there are suitable locations for SHP projects.

2.3.1 Argentina

Ariel Marcheniagi; Raul Pablo Karpowicz, Colegio de Ingenieros Civiles de la Provincia de Cordoba

Key facts

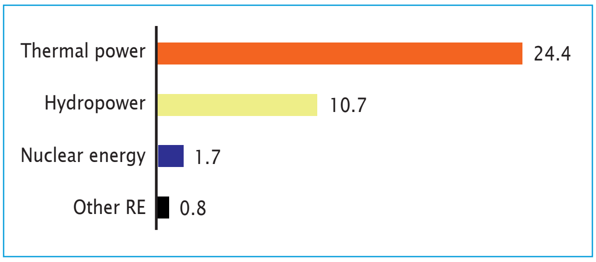
Population	42,980,026[1]
Area	2,780,000 km[2]
Climate	The vast extent of the country and the great range in altitude ensures that the country has a diverse climate. Throughout Argentina, January is the warmest month and June and July are the coldest. As the prevailing westerly winds lose their moisture and descend into Argentina, temperatures increase while humidity decreases. The north of the country has a warm and humid sub-tropical climate. Central Argentina has a temperate continental climate, with very hot summers and mild winters. The south of the country has a sub-arctic climate and is directly influenced by the prevailing westerly winds. [2]
Topography	The terrain comprises rich plains of the Pampas in northern half, flat to rolling plateau of Patagonia in south, and rugged Andes along western border. The highest point is Aconcagua, at 6,960 m.[2]
Rain pattern	Rainfall is variable, depending on location and elevation. The north has rain throughout the year with the annual average of around 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.[2]
General dissipation of rivers and other water sources	The major rivers in Argentina include the Pilcomayo, Paraguay, Bermejo, Colorado, Río Negro, Salado, Uruguay and Paraná, the largest river. 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 the Mendoza in the homonymous province, the Chubut in Patagonia, the Río Grande in Jujuy, and the San Francisco River in Salta.[4]

Electricity sector overview

The total installed capacity in Argentina in 2013 was 37.6 GW, consisting of thermal (24.4 GW), hydropower (10.7 GW), nuclear energy (1.7 GW), and the remainder from other renewable energy (RE) sources (Figure 1).[16] The total electricity generation in Argentina in 2014 was 131,205 GWh; the main sources of generation were thermal (83,265 GWh), hydropower (40,663 GWh) and nuclear energy (5,228 GWh).[12]

FIGURE 1

Installed capacity by sources in Argentina (GW)

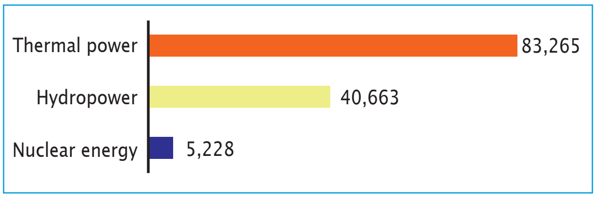


Source: EMIS[16]

The Compañía Administradora del Mercado Mayorista Eléctrico (CAMMESA) is the administrator of the electrical market and the National Electricity Regulatory Commission (ENRE) is an independent entity within the Secretariat of State for Energy. ENRE is responsible for regulating the energy industry.

FIGURE 2

Electricity generation by sources in Argentina (GWh)



Source: IJHD[12]

The electrification rate in Argentina is 95 per cent. The average pre-tax cost per MW for domestic and industrial consumers is US$0.27 and US$0.58, respectively.

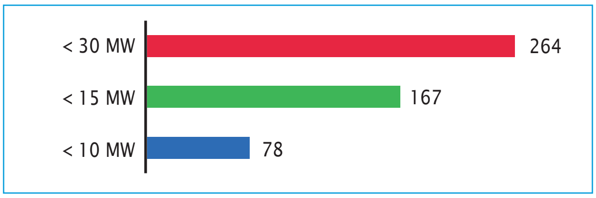
Small hydropower sector overview and potential

Currently in Argentina, hydropower plants with an installed capacity up to 30 MW are considered small hydropower (SHP) plants, as stated by the Secretary of

Energy in 2015, marking a change from the previous definition, which encompassed plants of up to 15 MW.[13]

FIGURE 3

Installed SHP by definition in Argentina



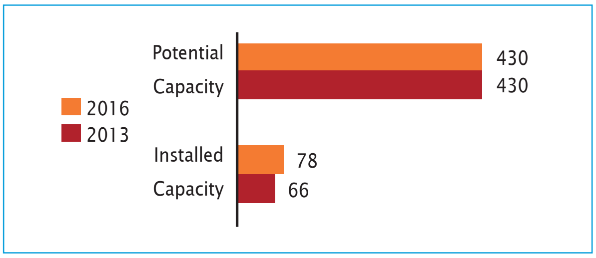
Sources: CAMMESA,[8] IRENA[10]

The data available from CAMMESA indicates that the current installed SHP is at least 264 MW (167.7 MW below 15 MW). The actual number could be as high as 321 MW, since the national utility database does not include all SHP plants in the country.[8] Meanwhile the World Energy Council's Argentine Member Committee has the number at 377 MW from a total of 75 micro, mini and SHP plants.[9] Using the standard SHP definition of up to 10 MW, the current installed SHP capacity is at least 78 MW,[10] however, it is likely to increase as more accurate data is made available (Figure 3).

The total SHP potential is still believed to be 430 MW.[14] Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by at least 12 MW, while potential capacity has remained the same (Figure 4).

FIGURE 4

SHP capacities 2013-2016 in Argentina (MW)



Sources: *WSHDR 2013*,[11] CAMMESA,[8] WEC,[9] IRENA[10]
Note: Current country definition is < 30 MW; data in the figure represents < 10 MW.
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Recent projects that are worth noting are: Salto Andersen, located in the province of Rio Negro, which started operating since 2011 with 7.9 MW installed capacity and electricity generation of 49.6 GWh/year; Lujan de Cuyo in the province of Mendoza with 1 MW capacity and 7.4 GWh/year generation (inaugurated in 2013); and La Lujanita, also in the province of Mendoza with 1.7 MW capacity and 7.5 GWh/year generation.

In terms of RE sources, the government prioritizes development of SHP plants (up to 15 MW), because these projects represent an opportunity for sustainable development in multiple geographic regions in Argentina.

The Energy Department has a national inventory of 116 SHP projects (less than 15 MW each) as identified in a site survey; the aggregate additional power supply would be nearly 430 MW. The results of the study favour, among others, development of isolated SHP in the southern region. Of the 116 projects reviewed, only four have reached implementation stage and only 20 have reached the feasibility stage.

With the need realised, a plan for a framework to develop SHP plants has been proposed. This plan will make further hydrological, geological, geotechnical and environmental impact studies (done for only 12 SHP sites). Other suggestions include the need to evaluate the additional environmental benefits, social cost of externalities, as well as the capability to supply potable drinking water.

While the overall SHP potential has been estimated to be 430 MW, there is a plan to develop 100 MW of this unutilized capacity within 10 years' time in different regions of the country. SHP projects with a total capacity of 30 MW are currently under development. The presence of turbine manufacturers who are part of the clean energy value chain of SHP within the country may facilitate meeting the desired targets.[3]

Renewable energy policy

The importance of renewable resources (i.e. photovoltaic, wind, biomass and SHP plants) as alternative sources for generating electricity in rural areas has increased through various programmes that are being conducted by the Ministry of Public Works and Services at the National Bureau of Promotion, in order to achieve basic power provision (lighting and communications), although the main authority on energy is the Ministry of Planning.[3]

Argentina has a national law for promoting RE sources (Law 26 190/06). Via a tax based incentive, a non-binding renewable target of 8 per cent is set to be achieved by 2016, in addition to a 7 per cent biodiesel and a 5 per cent ethanol blending mandate. Studies and maps show the RE potential in each province.

In the same year, the national government, together with Energía Argentina Sociedad Anónima, the public power company, launched the GENREN Programme, which offers to buy 1,000 MW of RE.[3]

With the aim of promoting RE in the country, in September 2015, the Argentinean Congress approved Law No. 27191 that intends to reach a goal of 8 per cent of the total electricity consumption from renewable sources by 31 December 2017 and 20 per cent by 31 December 2025. The Law No. 27191, which amended Law No. 26190, also includes benefits for hydroelectricity developments up to 50 MW, including feed-in tariffs as well as tax benefits for RE generation and electromechanical assembly. Currently, the approved law is under regulation process. The time requirements set by the law pose a challenge for SHP development, as it requires longer periods for planning and installation compared to other renewable sources. The beneficiaries are investors of RE projects and the benefits differ depending on when the project started. Among another benefits there are tax reductions and VAT exemptions for investors.[4]

Consequently, private producers must generate their own RE or sign contracts at an average price of up to US$113/MWh traded between parties.

Article 14 of Chapter VI states that all investment projects that meet the of the scheme established by Law 26.190 will be exempt from the payment of import duties and all other duties on imported equipment necessary for the energy project.[5] Exemptions or consolidation of duties and taxes will also be extended to imports of capital goods, parts, components and supplies for the production of equipment for power generation from renewable sources and intermediate goods in the value chain of manufacturing equipment. Power generated from renewable sources may be sold both domestically and for export.[6]

The Enforcement Authority will determine how to comply with the required accreditation. However, article 16 states that benefits set out in Chapter VI shall be valid until 31 December 2017.

Legislation on small hydropower

The SHP action plan outlined by the National Directorate for Promotion (DNPROM) of the Ministry of Energy comprises:[3]

- A survey of the facilities in operation and out of service, as well as those able to be refurbished, and of public irrigation works that can be equipped with generating units;
- A search for new sites and to select a methodology for estimating total theoretical potential of regions and basins;
- Compilation, review, and proposal of reformulating the provincial legal regimes of water, environment and energy, in agreement and collaboration with governments and provincial agencies;
- An analysis of the profitability of SHP in isolated markets, the 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.

The Energy Department's Office is currently bound to encourage the construction of the 116 micro-hydro plants mentioned above. The government is considering several possibilities to avoid an energy crisis, which would impact economic growth. One strategy is designed to further develop the country's water resources through small-hydro facilities, which individually have a generating capacity of up to 30 MW. Financial capacity is a key element to consider, particularly in the case of private investors looking for opportunities in the SHP sector. Studies show that in order to encourage private initiatives, financial mechanisms are essential as they allow the collection of long-term loans at rates appropriate to the realities of such projects.

Furthermore, it will be necessary to implement a system of guarantees that awards credits to private investors so that they are not inhibited by other commercial arrangements. At this point, the intervention of the federal, provincial and/or municipal state to facilitate and manage credit is needed. There is also a need to have an adequate remuneration system for the energy sold by SHP. When deciding the tariff structure of SHP, it is pertinent to consider the environmental benefits and the social cost of externalities affecting the company, but which are not incorporated by the generators yet. Argentina, which has a weak penetration of RE in the national electricity supply, opted for the regulatory mechanism of 'quotas' for grid access. This system is advantageous for states with funding problems but does not ensure private investment.[3]

Barriers to small hydropower development

Argentina has great SHP potential, but a number of very diverse barriers hinder its realization. Hydropower is considered the most promising technology for national development, followed by wind, solar and biomass. There are political constraints and structural limitations within the governmental agencies responsible for establishing policies that provide solutions to these problems. It is necessary to apply instruments that help formulate and implement an energy policy that includes RE. At the moment the regulatory framework remains insufficient.[7]

Foreign investors perceive high risks and a lack of incentives based on the limited availability of local finance. Local finance is hindered by the limited number of local banks and the lack of liquidity experienced in commercial banks. Furthermore, the difficulty in securing capital at reasonable costs in the short term strongly hinders the volume of investment, despite the country's resource potential.

It is necessary to acknowledge that programmes like GENREN are being implemented, in which the generator is not paid a premium but a guaranteed price for the energy generated in order to provide a more reasonable rate of profit.

There is a specific need to update the incentives posed by Law 26190. It is not easy to meet the target to cover 8 per cent of electric demand with emerging RE, as established by the law, without implementing the policies, instruments and specific promotional activities, particularly those aimed at financing.

2.3.2 Bolivia (Plurinational State of)

Cleber Romao Grisi, WHITEnergy Bolivia

Key facts

Population	10,027,254[1]
Area	1,098,581 km²
Climate	Bolivia has a continental climate, cold winters and hot summers divided into three regions. The Andean zone has strong and cold winds with high solar radiation and maximum temperature of 20°C and minimum below 0°C. The Sub Andean zone is humid and rainy, with temperatures varying from 15°C to 25°C on average. The Lowlands are rainy and humid, with an average temperature of 30°C.[1,2,4]
Topography	There are three geographic zones: the Andean zone, the Sub-Andean zone and the Lowlands. These areas feature great variations in altitude, from an elevation of 6,542 m above sea level at the Sajama peak to nearly 90 m at the Paraguay River.[1,2,5] Bolivia has a high level of biodiversity, considered one of the greatest in the world, as well as several eco-regions such as mountains, high altitude flats, tropical rainforests, dry valleys and tropical savannahs.[2]
Rain pattern	As in a tropical climate, the rainy season is at the end of spring and all summer (middle of October to early April). It is much more pronounced in the Lowlands, with precipitation patterns that vary from 2,000 mm per year in the north to 600 mm per year in the south.[7,8,9]
General dissipation of rivers and other water sources	The most important rivers start in the Andes and descend across the valleys into the low tropical lands. Bolivia has three main watersheds and river systems. The Amazonian Basin runs from east to west, and constitutes mainly 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 Rivers cross the often-flooded northern savannah and tropical forests, all converging in the northeast to form the Madera River; which flows into Brazil.[2,5] The Central or Lake Basin is formed by the Titicaca and Poopó Lakes, the Desaguadero River and large salt lakes like the Coipasa and Uyuni. Titicaca Lake is 222 km long and 113 km wide. With its surface at an altitude of 3,805 m, 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.[2,5] Finally the South or Plata River basin is where the Pilcomayo and Bermejo Rivers cross the Chaco to the south-east, leaving Bolivia to form the border between Paraguay and Argentina.[2,5]

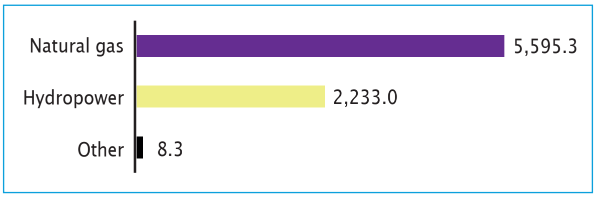
Electricity sector overview

The total installed capacity of the national grid in 2014 was 1,614.7 MW. During this period, the maximum instantaneous power demand was 1,298.2 MW while the annualized total demand in Bolivia reached 7,477.7 GWh, the highest in the past 15 years. This represents 8 per cent growth in power demand compared to 2013.[12] Although currently there is a lack of accurate data from the isolated power networks in Bolivia, it is estimated that the demand is around 600 GWh annually (2014) with an estimated installed capacity of 179.4 MW (2012).[12]

In 2014, the country generated 7,836.55 GWh annually, with 5,595.3 GWh produced by natural gas turbines with an installed capacity of 1,146.5 MW (69.3 per cent) and producing 5,595.3 GWh annually (71.4 per cent). This was followed by hydropower with 465.2 MW capacity (28.8 per cent) and 2,233.0 GWh generation. Other small sources include wind and biomass with a total installed capacity of 30.5 MW (1.9 per cent) producing approximately 0.1 per cent of the energy demand (Figure 1).[12]

FIGURE 1

Energy Generation in Bolivia (GWh/annum)



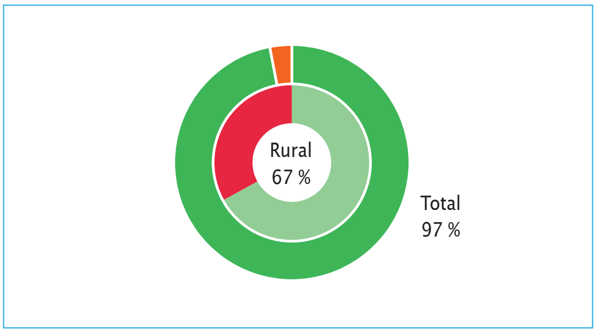
Source: Comité Nacional de Despacho de Carga[12]

The electricity sector of Bolivia consists of the national interconnected grid, the Sistema Interconectado Nacional, as well as several isolated networks. The National Grid extends along the regions of La Paz, Oruro, Potosí, Chuquisaca, Cochabamba, Santa Cruz and Beni.

There are 3,440.3 km of transmission lines including 1,970 km at 230 kV, 1,356.2 km at 115 kV and 112.1 km at 69 kV.[12] In 2011 there were 38 operational and registered isolated networks, most of them located in the regions of Pando, Beni, Santa Cruz and Tarija. The energy produced in these isolated networks was mainly thermal gas fired (69 per cent) and diesel (27 per cent) powered units and some hydropower generation (4 per cent).[13;14] The total population access to electricity was expected to be approximately 87 per cent by the end of 2015. Urban coverage was 97 per cent and rural 67 per cent (Figure 2).[12]

FIGURE 2

Electrification rate in Bolivia

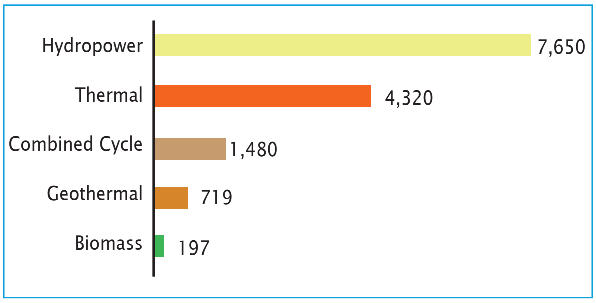


Source: Comité Nacional de Despacho de Carga[12]

According to the energy sector authorities, electricity demand will reach 14,336 GWh annually by 2022 and will increase to more than 22,000 GWh annually by 2030, requiring a total installed capacity of 2,297 MW in 2022 and more than 3,500 MW in 2030.[13] The potential sources for this energy to be produced in 2022 is shown in Figure 3 below. Approximately 53 per cent of this future demand will be fulfilled by hydroelectric power.[13]

FIGURE 3

Estimated energy demand in 2022 (GWh)



Source: Ministerio de Hidrocarburos y Energía[13]

The Spot Market for wholesale energy transactions and the end consumers' market commercially constitute the electricity sector in Bolivia. In relation to the energy production chain in the interconnected national grid, the electricity sector is divided into three areas: generation, transmission and distribution. According to the laws, a single company is not allowed to participate in all three areas of the energy production chain, except for the national electricity company, the Empresa Nacional de Electricidad (ENDE), if they have not been specifically authorized to supply end consumers in an isolated network.[16]

As a public entity, the electricity sector in Bolivia in mostly owned by the government. Between 2006 and 2009, there was a tendency to nationalize (i.e. purchase private shares) the private companies participating in the energy sector. The nationalization process ended in 2009. The nationalized electric companies, including thermal and hydroelectric generating facilities, transmission lines and distribution utilities, as well as service companies, are under the ENDE is the public entity now responsible for the operation and maintenance of the existing facilities, to administrate the national grid, to plan the electrical market growth and to develop energy projects. Private companies have a minor role in the electricity sector, which does not include generation, transmission and distribution.[12,16]

Electricity end users are classified into two groups. The first group consists of non-regulated consumers. When the demand of a single end user exceeds 1 MW they participate in the spot market and are allowed to make purchase agreements previously authorized by the control and regulation authority. The second group consists of regulated consumers, comprising end users with a demand below 1 MW. They are supplied by local electricity distribution companies.[12,16,17]

The government authorities and institutions that regulate the Bolivian electricity sector are: the ministry Ministerio de Hidrocarburos y Energía, the vice ministry Viceministerio de Electricidad y Energías Alternativas, the regulation and control authority Autoridad de Fiscalización y Control Social de Electricidad (AE), the interconnected system regulation, control and operation entity Comité Nacional de Despacho de Carga (CNDC) and the Government's electricity utility Empresa Nacional de Electricidad (ENDE).[12,16,17]

The following laws, regulations and operational standards regulate the energy sector in Bolivia:

- Electricity Law No. 1604, published 21 December 1994. This law defines the Electricity Sector principles, institutional organization, operations structure and economic model. This law is currently under review and changes may be applied.
- Supreme Decrees and Regulation Statements: These documents are published to complement the Electricity Law stating the operations and economical detailed framework for the electricity sector.[12,16,17]
- Operational rules: Developed and published by the national grid administrator (CNDC), reviewed and approved by the AE, these documents establish the detailed procedures for the coordination, management and operations of the electricity sector.[12,16,17]

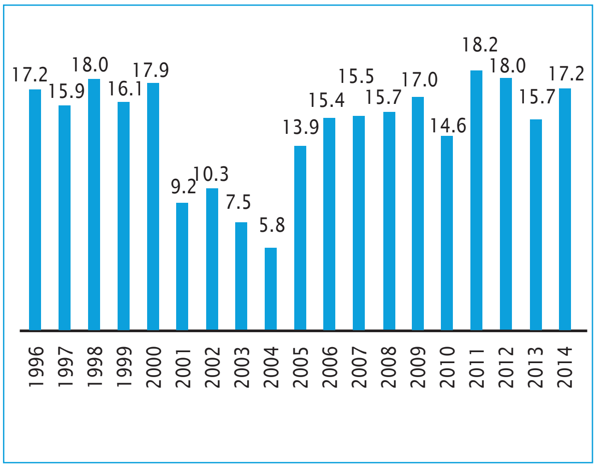
Despite the energy sector being predominantly thermal, the electricity tariffs in Bolivia are the lowest in South America due to the subsidised gas and diesel prices for energy production. The generators connected to the national grid are paid by a combination of energy tariffs and available power of their installed capacity.[12]

For import-export through the interconnected grid, energy price is established in the spot market by the marginal cost. This represents the economic cost to generate the next kWh required by the system. All generators are paid for their produced energy at the marginal cost rate multiplied by a factor that considers the payment of losses and transmission. The tariff scheme is based on the marginal theory, and its calculation is made from the use of optimization models and simulation of the operation.

The grid's administrator, the CDNC, is responsible for modelling the energy production in the short, mid and long term, ensuring the most economical generation scheme in order to keep the marginal generation cost as low as possible.[12] The average marginal cost in the spot market during 2014 was US$17.2/MWh. Figure 4 shows the marginal cost variation since 1996. It shows that the marginal cost has been relatively stable, varying from US$15/MWh to US$18/MWh in the last five years.[12]

FIGURE 4

Generation marginal cost (US$/MWh)



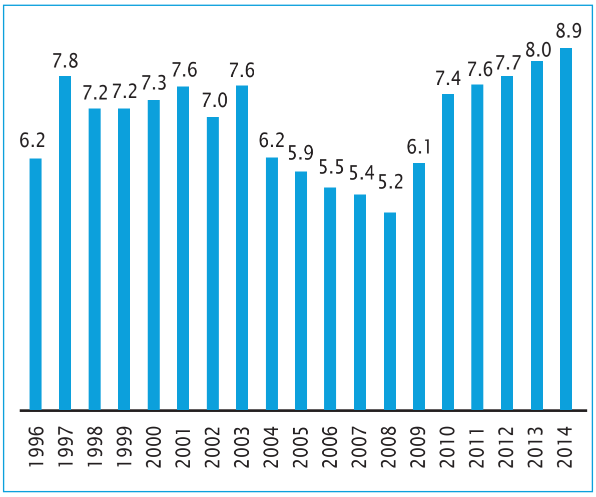
Source: Comité Nacional de Despacho de Carga[12]

The power installed capacity availability price is set at special prices according to the node where the transmission network is connected and the price is representative of a calculated cost related to estimated investment and fixed operation cost required to supply the demand plus a reserve in the long term. In other words, it is a value representing the long-term generation marginal cost to guarantee the demand energy supply.[12]

The average power installed capacity availability price in the spot market during 2014 was US$8.9/kW per month.

FIGURE 5

Power installed capacity availability spot market price (US$/kW per month)



Source: Comité Nacional de Despacho de Carga[12]

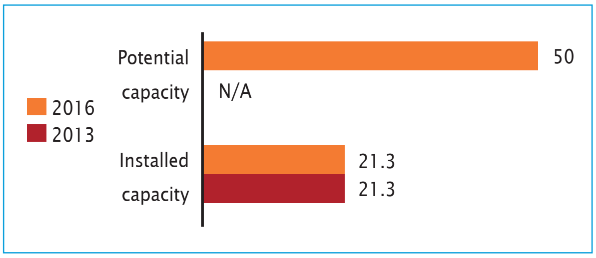
Figure 5 shows the power cost variation since 1996 where the cost varied from US$7.4/kW per month to US$8.9/kW per month in the last five years.[12]

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. The installed capacity of SHP in Bolivia is 21.3 MW while the potential is estimated to be at least 50 MW. This indicates that approximately 43 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, the installed capacity has remained unchanged (Figure 6).

FIGURE 6

SHP capacities 2013-2016 in Bolivia (MW)



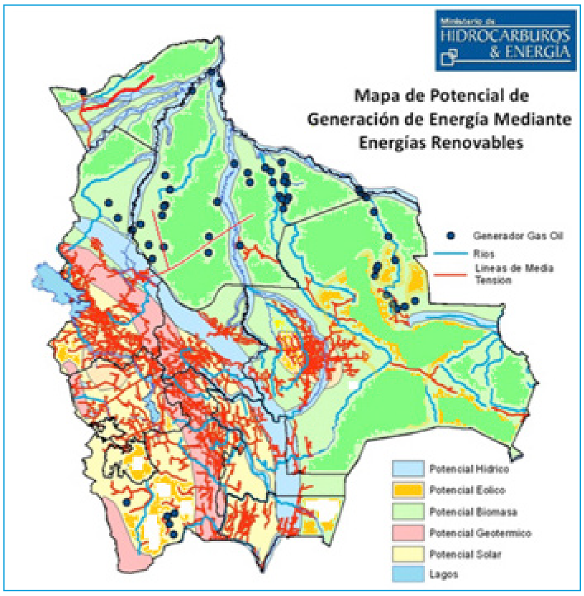
Source: Ministerio de Hidrocarburos y Energía,[20], *WSHPDR 2013*[20]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

According to the National Energy Strategic Plans, the government has set a goal to change the current energy production mix from mainly thermal to hydro and also to increase other renewable energy (RE) sources.[13,15] The most suitable region to develop hydropower is the

Amazonian basin with a potential to install 34.2 GW, followed by the Plata River basin with 5.4 GW.[18] The lowest hydro potential is in the Andean Basin (Altiplano), with a potential of 0.3 GW. However, by 1993, ENDE identified about 81 SHP projects with a total installed capacity above 7 MW.[18] The following map shows the RE potential along the Bolivian territory. The light blue areas are suitable for hydropower energy with the potential to install a total 39.9 GW of large, medium and SHP projects (Figure 7).[18] Since 1993, only two hydro projects were developed: the 90 MW Hidroeléctrcia Boliviana S.A. (2002) and the Miguillas and San Jose' with a total capacity of about 400 MW, which became operational in 2015.

FIGURE 7

Renewable Energy Potential Map



Source: Ministerio de Hidrocarburos y Energía[19]

The government's strategic plan includes developing hydro projects that have capacities of less than 30 MW as classified by the following criteria:[19]

- Micro: P < 500 kV;
- Small: 500 kV < P < 5 MW;
- Medium Small: 5 MW < P < 30 MW.

The strategic plan includes SHP projects with approximately 30 MW grid connected and other 20 MW in isolated networks. Currently, all projects are in progress of identification. Such projects, as well as other endeavours, can be studied, developed and constructed by public or private investment and for connection to the national grid or to supply isolated networks.[19]

Legislation on small hydropower

The special physiographic country setting provides many options for SHP development on the water flows and waterfalls, although, these sites need to be identified. Therefore, private studies should be conducted followed by project development, provided that all regulations, laws and social needs are fulfilled. The authorities are aware that the energy prices and other financial conditions are insufficient to provide an interesting rate of return for a SHP project investment or any other renewable source. Therefore, the government is working to establish a policy in order to finance hydro and other renewable projects by creating a fund that allocates for a reduction in thermal production, either gas or diesel, in favour of subsidizing RE sources. The authorities are also working to establish structure and rules to finance SHP and other RE developments by providing incentives to the local (department) government when the installed capacity is < 2 MW and to the municipalities or to the indigenous authority when the project is of an installed capacity < 1 MW.[19]

Renewable energy policy

The government has set the goal to change the energy matrix from mainly thermal to mainly RE sources, especially hydropower. Bolivia has great hydropower potential, making it important to encourage its development. Increased use of the RE share would also help to reduce the use of natural gas which would allow for increased exports of gas to Brazil and Argentina, where prices are up to seven times higher.[12,13,16]

In 2014, the government published the new investment promotion law, as well as Supreme Decree #2048 for the remuneration of RE projects. Both of these are meant to promote investment in the electric sector, especially for hydro, wind, geothermal and solar projects. This indicates that the political scenario is becoming more suitable and attractive for both foreign and local investment in the electricity sector.[19] RE projects, including run-of-river hydro schemes will not be remunerated according to the actual electricity tariff system, but will only be paid for energy production as stated in the Supreme Decree #2048.[19] However, the energy tariffs for new projects are not defined yet. Financial mechanisms, regulations and investment frameworks are also in the process of being implemented. Each project will have to be negotiated to establish the energy price through a purchase agreement according to ENDE's requirements, the investor interests and AE's authorizations. Some planned benefits to SHP projects may include: [19]

- Exemption of taxes for importing equipment and construction;
- Subsidies from the government's RE fund;
- Guaranteed electricity purchase price by a mid or long term purchase agreement ensuring to cover the generation costs and to receive an acceptable investment return rate;
- Stable tributary conditions for 10 years;
- To defer the aggregated value tax payment in five years since the beginning of the commercial operation date;
- Potential exemption from paying the transmission and the grid administrator (CNDC) fees.

Barriers to small hydropower development

The main challenges to consider for developing SHP projects in Bolivia are:

- RE development framework, rules and conditions have yet to be established;
- Low energy prices;
- Poor quality of hydrological, climate and statistical data, especially for remote areas far from the main cities;
- Difficult to establish a private project/company to compete with the low prices;
- Difficulties dealing with the social conditions in Bolivia. Roadblocks and protests can interfere with project development, construction and further operations;
- Projects can be cancelled due to lack of social acceptance;
- Government procedures, authorizations and paperwork can take a long time. The bureaucracy in Bolivia is complicated and procedures and paperwork often take longer than expected. Previsions have to be taken in order to comply with deadlines related to legal paperwork.

2.3.3 Brazil

Geraldo Lúcio Tiago Filho, Camila Rocha Galhardo, Luciano José da Silva and Lucas Rissatto, Federal University of Itajubá

Key facts

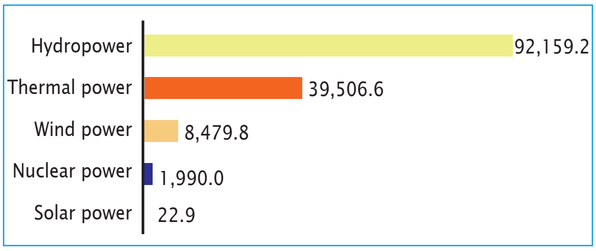
Population	202,768,562[1]
Area	8,515,692 km[2]
Climate	The climate is mainly tropical, but temperate in the south and equatorial in the north. In the Amazonian region average temperatures reach over 26°C-28°C. The north-east region is humid, tropical and semi-arid with averages between 20°C and 28°C. In the south-east region average annual temperatures vary between 19°C and 24°C. However, in the south, the coldest regions are those with average temperatures below 20°C. During the winter, the average values in June vary between 11°C and 18°C.[3]
Topography	The Brazilian territory basically consists of crystalline solid (36 per cent) and large sedimentary basins (64 per cent). Approximately 93 per cent of the Brazilian territory presents altitudes of below 900 m. Most of the geological structures are old, dating back to the Paleozoic and Mesozoic Eras in the case of sedimentary basins and the Precambrian Era in the case of solid crystalline.[4]
Rain pattern	In the Amazonian region the annual atmospheric precipitation is 2,300 mm on average, but there are locations where precipitation exceeds 5,000 mm/year. The north-east region presents annual precipitation of between 300 mm and 2,000 mm. In the midwest, precipitation is well spread and is about 1,500 mm/year. In the south-east, rainfall ranges between annual averages of 1,250 mm and 2,000 mm, exceeding 4,500 mm in Bertioga, on the central coast of São Paulo state.[3]
General dissipation of rivers and other water sources	The eight main drainage basins all drain into the Atlantic Ocean. The Amazon and the Tocantins-Araguaia Basins account for over half of the drainage. The Amazon River and its tributaries, accounting for one-fifth of the world's freshwater, cover almost half of the territory, within it flows. While the Amazon flows for more than 3,000 km within Brazil, the waters only decline by 100 m. Its major tributaries include the Javari, Juruá, Purus, Madeira, Tapajós, Xingu and Tocantins on the southern side, and the Branco, Japurá, Jari and Negro on the northern side.[2,3]

Electricity sector overview

In 2015, the total installed capacity of the power grid in Brazil was 142,158.5 MW (Figure 1). The generation capacity of hydropower, including imports, was 407.2 TWh. In total, the participation of renewable sources reached 74.6 per cent. Final power consumption was 531.1 TWh;[6] electricity supply was 624 TWh, with 590 TWh from domestic generation and 33 TWh from net imports.[25]

FIGURE 1

Installed electricity capacity in Brazil (MW)



Source: Agencia Nacional de Energia Elétrica[6]

According to the 2010 Census, the electric grid covered 97.8 per cent of Brazilian households. The coverage varies between urban areas (99.1 per cent) and rural areas (89.7 per cent).[8] In 2012 electric power transmission and distribution losses reached 17 per cent.[24] In 2013, 99.7 per cent of the population had access to electric power. Most of the areas without access were composed of rural communities mostly located in remote and isolated regions within the Amazon Rainforest.[8] The government's Light for All Program is mainly responsible for providing electricity to the Brazilian population. Since its implementation 10 years ago, the programme has made over three million installations, representing 5 per cent of the total number of residential consumers in the country, totalling about 15 million people benefitting from access to electric power.[9]

With regard to consumption per sector, in 2013, residential consumption was the largest (expanding 6.2 per cent above the number registered in 2013), followed by business and services (5.6 per cent rise from 2012). Together, these sectors consumed 209 TWh, representing about 45 per cent of the total electric energy consumed by the distribution network. In 2014, the commercial sector had the lowest energy consumption growth rate since 2009, when the total consumption declined 1.1 per cent due to the global economic crisis in late 2008. The industrial sector, which is a major energy user, is also responsible for the decline in consumption.

Policies for the energy sector, and specifically the electric power sector, are drafted by Federal Executive Power through the Ministry of Mines and Energy (MME), with advice from the National Council for Energy Policy (CNPE) and National Congress. The National Electricity Agency (ANEEL) acts as a regulatory agency and the Electric System National (ONS) is responsible for coordinating and supervising the centralized operations of the interconnected system. The Electric Sector Monitoring Committee (CMSE), in connection with the MME, was instituted to permanently keep track and evaluate the continuity and security of the electro-energetic demand in all of the national territory, aside from suggesting necessary actions. There are also other agencies like the Energy Research Company (EPE), linked to the MME, whose function is to carry out the necessary studies for planning the expansion of the electric system. Another is the Chamber of Electric Energy Commercialization (CCEE), which hosts energy trading in the free market.[11]

Since 2004, the Brazilian electricity sector includes two trading environments: the Regulated Contracting Environment (ACR) having electricity generation and distribution agents, and the Free Trade Environment (ACL) having generators, distributors, traders, importers, exporters, and free and special consumers. There is also the spot (short term) market where the adjustment between the contracted and measured volume of energy is promoted. With the objective of reaching reasonable tariffs, auctions were incorporated in the current model, working as an instrument for distributors to purchase energy in the regulated environment. The auctions are held by CCEE, delegated by ANEEL, and follow a low tariff criterion in order to reduce the acquisition cost of energy to be passed on to retail consumers.[11]

In order to generate and transmit energy, the country counts on a principal system called the Interconnected System (SIN). This network covers most of the country and consists of connections made over time. These installations which were initially restricted to exclusive service for the region of origin: south, south-east, mid-west, north-east and part of the north. In addition, there are many smaller systems that are not connected to the SIN; these isolated systems are mainly found in the Amazonian region in the north. Due to the geographical characteristics of the region, which is dense and contrasted with extensive and rushing rivers, building long transmission lines to connect to the SIN is extremely difficult.[11] Currently, the subsystems in the north are slowly being connected to the SIN.

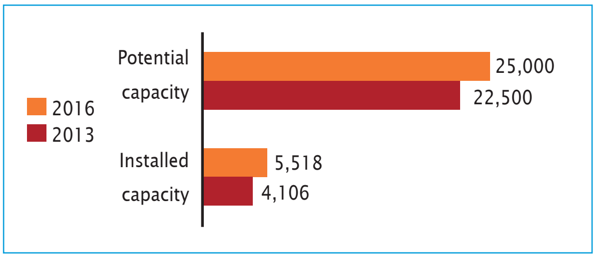
In 2013, the average Brazilian tariff was R$254.17/MWh (US$67.20/MWh), the most expensive in the north and the least in the south. There are variations according to consumer class between R$286.09/MWh (US$75.74/MWh), (public authority) and R$161.27/MWh (public illumination). With regard to supply voltages, the average tariff ranged between R$272.38/MWh (US$72.03/MWh) for low voltage to R$142.94/MWh (US$51.23/MWh) for voltages above kW.[9]

Small hydropower sector overview and potential

As of the beginning of 2015, small hydropower (SHP) plants in Brazil are limited to those with an installed capacity above 1 MW and below 30 MW, as well as having a flooded area that does not exceed 3 km^2.[13] Brazil has a SHP installed capacity of 5,518.50 MW. The SHP potential is 250,000 MW.

FIGURE 2

SHP capacities 2013-2016 in Brazil (MW)



Source: *WSHDR 2013*,[23] Agencia Nacional de Energia Elétrica (ANEEL)[6]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

With Resolution 652 in 2003, the flooded area had authorization to reach 13 km^2, as long as it meets the equation $A \leq (14,3 \times P)/Hb$, where P is the power of the project given in megawatts (MW) and Hb is the gross head available, given in metres (m); or when the reservoir has been scaled based on uses other than electricity generation.[14] Hydropower projects with power below 1 MW are classified as Hydropower Generating Plants and receive simplified treatment from ANEEL in terms of registration procedures.[1]

Studies show that Brazil still has about 25,000 MW of SHP potential available. These estimates used a logistic growth curve as a model, based on the growth of SHP plants from 2005 to 2009, and considered inflexions to the growth of installed capacity of SHP after 2023. The growth rate in 2023 was predicted as less than 5 per cent per year since available power would increasingly become scarce and more expensive. The study points out that in the decade of 2030, SHP installed capacity should be about 8,500 MW and in 2050 about 12,000 MW. The growth rate of SHP installed capacity is projected to stagnate in the decade of 2070.[16]

According to ANEEL in April 2015, Brazil was operating 491 hydropower plants with capacities ≤ 1 MW (0.23 per cent of the total), totalling 317.4 MW, as well as 474 plants with capacities of 1-330 MW, corresponding to 4,772.1 MW (3.53 per cent of the total). Of these ventures, most grants are generally given to private equity.[6]

In mid-2015, 38 SHP projects were being built, totalling 429 MW of installed capacity. According to the 2023 10 Year Plan of Energy Expansion the Brazilian Government foresees that the energy matrix, with relation to SHP plants, will add 2,011 MW to the system between 2013 and 2023. While it is a large achievement for SHP development, it is a notably discrete growth with relation to the increments observed for large hydro, wind, biomass, and solar, with growths of 32,265 MW, 20,248 MW, 4,116 MW and 3,500 MW respectively.[17]

Legislation on small hydropower

Among the renewable sources, SHP plants are losing ground to other sources, mainly wind. In the last few years, the auction prices for wind energy have shown to be lower than those of SHP. Compared to other sources, the cost of construction and operation of SHP has been shown to be more expensive. The costs for civil construction and electromechanical equipment are high and are not eligible for tax exemptions, unlike the equipment for wind parks. The equipment for wind parks are exempt from taxes such as Circulation of Merchandise and Services Tax and parts used for the wind generators are exempt from programmes such as the Social Integration Program/Public Service Asset Formation Program and the Contribution to Social Security Financing.

There are difficulties found in the environmental licensing processes. According to CONAMA Resolution 01/86, Article 2, construction activities for power generation are potentially impacting to the environment, and are therefore subject to Environmental Impact Studies (EIA) and Environmental Impact Reports (RIMA). This applies to any power plant, regardless of source, with power above 10 MW. Under this regulation, the EIA is required for all hydropower plants with power of 10-30 MW.[17] SHP plants are also classified as ventures with high impacts to the environment graded at 3 in a classification that ranges from 1 to 5. However, SHP plants with less than 10 MW can meet the requirement through the Simplified Environmental Report.[19]

However, in 2015, with the changes in auction rules, especially in terms of cap prices, it was possible to recover the sale of SHP energy in a significant way. In addition, with the provisions of Law 13.097/2015, it is likely that many projects with installed capacities of 1-3 MW will have their processes simplified and made less expensive. They will then be able to come into operation.

In the future, as SHP plants are built in the country, the location for greater heads and better flows will be exploited first over smaller heads and flows, thus, in most cases, making them economical. While the market should continue to grow with the current measures, it is likely to be slower growth, and converge for saturation. SHP plants should continue to be part of the composition of the clean and renewable energy matrix in Brazil, but in a small fraction.[16]

In Brazil, SHP investments are financed by banks, mainly the National Bank of Social Development (BNDES), whose main line of credit provides a grace period up to six months after the project begins commercial operation, with amortization up to 20 years. The bank finances up to 70 per cent of the value of financeable items, except for hydropower plants above 30 MW, in which case BNDES finances up to 50 per cent of the financeable costs.[19]

Renewable energy policy

According to the 10 Year Plan elaborated by the Brazilian Energy Research Company, by 2023, the participation of renewable sources in the Brazilian energy matrix will increase from 41 in 2013 to 42.5 per cent. The evolution of the installed capacity of renewable sources in the Brazilian energy matrix will increase from the current 82.9 per cent to 83.8 per cent in 2023. Wind energy with current 1.8 per cent in the energy matrix will rise to 11.6 per cent in 2023, due to the expansion of 20 MW within the time period.[17]

Concerned with climate change, Brazil was first to sign the United Nations Framework Convention on Climate Change for the United Nations Conference event on Environment and Development, held in Rio de Janeiro in 1992. Two years later, the National Brazilian Congress ratified the Convention, which officially came into effect in the country in March 2009, through Law 12.187 of 29 December 2009. The country instituted the National Police on Climate Change (PNMC) establishing principals, objectives, guidelines and instruments on the matter.[22]

Barriers to small hydropower development

During the process of evolution, the Brazilian hydropower sector acquired significant experience and knowledge in the areas of design, manufacturing and assembly of electromechanical generating equipment, which have been enhanced and consolidated. The remaining hydropower potential is found in environmentally delicate regions, like the Amazon Rainforest. Development of these resources requires the project to be small and without any reservoirs. However, the increasing energy demand pushes for large hydropower installations.

Since the Brazilian energy sector model favours the sale of low cost energy, SHP is left at a disadvantaged position in comparison to other renewable sources, mainly because it does not have the same amount of tax incentives as other sources do. With reformulations in the energy auction rules in 2015, which establishes larger cap costs and makes sources more equally competitive, SHP plants are seen to be recovering in the regulated market. In addition, environmental barriers are common during the licensing process. There are hopes that Law No. 13.097/2015 will make the formalities of projects with installed capacities of 1-3 MW easier. Generally speaking, the difficulties are more present in the regulated market and there are more opportunities in the free market.

2.3.4 Chile

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Key facts

Population	18,006,407[1]
Area	756,100 km^2 (continental territory), 2,006,096 km^2 (continental, Antarctic and insular)[2]
Climate	Chile has a variety of climates: desert, Mediterranean steppe, warm temperate 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. Easter Island has a subtropical climate with oceanic influence characteristics.[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. Between continental and southern Chile there is a submerged mountain range whose highest peaks emerge forming islands, finally reaching the north-eastern tip of the Antarctic Peninsula. Easter Island presents a relief of plains and volcanoes.[2]
Rain pattern	Rainfall varies in amount and distribution across the territory. It increases while moving 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]
General dissipation of rivers and other water sources	As a result of the relief and the narrowness of the territory, the rivers are short, with steep slopes, low flow, torrential that are unsuitable for navigation but have great hydroelectric 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 as well as snow thawing and glaciers.[2]

Electricity sector overview

The Chilean electricity market has been 100 per cent private since 1986. The Chilean electric system can be described in terms of its interconnected power systems, energy supply, transmission, and distribution systems.

The larger interconnected systems are the North Interconnected System (SING), which supplies the north of the country, and the Central Interconnected System (SIC), in the central part of the country which serves 90 per cent of the population. SIC and SING, will be interconnected soon to increase efficiency and safety. Other smaller networks are the Aysén System, Los Lagos Generating Unit and Magallanes System.

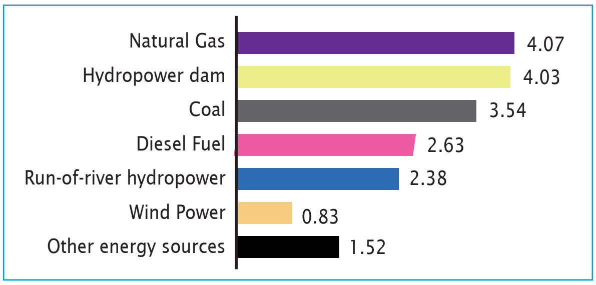
The total installed generating capacity in March 2015 was 19 GW, of which 14.9 GW corresponded to SIC and 3.9 to SING.[3] Figure 1 shows the installed capacity by energy source. The total electricity generated in 2014 was 69,897 GWh.

The sale price of electricity in March 2015 was CLP 63.3/kWh (US$0.09), the highest in Latin America. Note that this value does not consider the costs of distribution or the charge for the use of trunk transmission system.[4]

Transmission systems can transport electricity from the generating plants located throughout the country to distribution companies' sub-stations and industrial consumers. The voltage levels used in the lines are between 23 kV and 500 kV, at a nominal frequency of 50 Hz.

FIGURE 1

Installed capacity by energy source (GW)



Source: The National Energy Commission[3]

Distribution system consisting of lines, substations and equipment is established in two voltage ranges:

- High voltage: between 400 V and 23 kV;
- Low voltage: less than 400 V.

The high voltage distribution networks work at different voltages: 12; 13.2; 13.8; 15 and 23 kV. The low voltage distribution networks work at 220/380 V.

Chile has two types of consumers, unregulated and regulated. A regulated client is one who pays a fee set by the authorities, calculated on the basis of a model distribution company operating efficiently. This segment comprises those with a connected capacity of less than 2 MW. Furthermore, those with power consumption between 500 kW and 2 MW, which are located in the concession area of a distribution company can choose to be free customers. These consumers represent approximately 66 per cent of total consumption in the SIC and 10 per cent of consumption in the SING. Free customers are those who agree upon conditions for electricity supply with generators or distributors. This segment is composed of consumers whose connected capacity is more than 2 MW and, by choice, those at more than 0.5 MW, typically industrial or mining industries.[6]

The Chilean electricity industry is closely related to different public and private institutions, which are related to multiple market players in different ways.

These institutions are:

- The 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 industry, ensuring compliance and advising the government on all matters related to energy.[6]
- The Electricity and Fuel Superintendence (Superintendencia de Electricidad y Combustible): The public agency responsible for overseeing the energy market, in order to have safe and quality products and services.[8]
- The National Energy Commission (Comisión Nacional de Energía): A technical body responsible for analysing prices, tariffs and technical standards that production, generation, transmission and distribution of energy companies must meet, in order to have quality and safe services, compatible with the cheaper operation.[9]
- The Centres of Economic Load Dispatch (Centros de Despacho Económico de Carga)*:* These centres govern the coordinated operation of the power plants, trunk transmission lines, sub-transmission and additional electrical substations operating in an electrical system in order to preserve the security of the service and provide the most economical operation.[6]
- The Panel of Experts: An organization with bounded capabilities composed of experienced professionals whose function is to decide, by binding effect, rulings on those differences and disputes arising in connection with the application of electrical legislation. The electric sector companies accept decisions by mutual agreement.[10]
- The Court of Defence of Free Competition (Tribunal de Defensa de la Libre Competencia: A special and independent judicial organization, subject to the Supreme Court, whose function is to protect free competition.[11]

According to information from the Ministry of Energy, the electrification rate is around 96.9 per cent, which exceeds 99 per cent in the urban sectors. However, there are still around 20,000 rural households without electricity

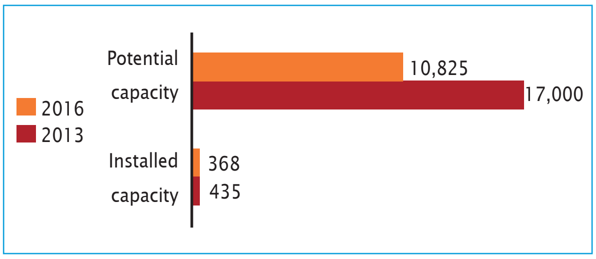
Small hydropower sector and overview

Chilean Law 20.257 defines a small hydropower (SHP) plant as one with a maximum installed capacity below 20 MW.[12] They are considered a form of Non-Conventional Renewable Energy (URE). The National Centre for Innovation and Development of Sustainable Energy further classifies hydropower into mini and micro hydropower. Mini and small hydropower plants are grid-connected and have an installed capacity of less than 20 MW, while micro hydropower plants are isolated and up to 300 kW.[13]

The installed capacity of SHP in operation as of March 2015, considering the SIC and SING, was 368 MW. Additionally, there are 86 MW under construction and 337 MW with Environmental Qualification Resolution, meaning that they have permission to start construction.[14] For installed capacity up to 10 MW, the total is estimated at 175 MW.[23]

FIGURE 2

Small Hydropower capacities 2013-2016 up to 20 MW



Sources: *WSHPDR 2013*,[22] National Center for Innovation and Development[13]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

As of April 2015, the potential, including Maipo and Yelcho Rivers, is equivalent to 10,825 MW. The most promising being the Biobio River (2,453 MW), Yelcho River (1,376 MW) and Maule River (990 MW). This corresponds to a potential of a technical nature, which considers the Rights of Use of Non-Consumptive Water for installed power greater than 0.1 MW and capacity factors greater than 0.5. This does not consider the potential in the southern area of the country.[15]

The potential associated with hydro reservoirs used for irrigation works, according to a study in 2007, is estimated at 866 MW, of which 558 correspond to plants that produce less than 20 MW and flow above 4 m^3/sec.[16]

Legislation on small hydropower

Laws 19940 and 20018 promote non-conventional renewable energies such as geothermal, wind, solar, biomass, co-generation and SHP. At first, these types of energies are given the provision of free transportation below 9 MW and with partial payment for 9-20 MW. Secondly, Law No. 20018 grants project owners 5 per cent of the total electricity distribution rights to meet the total demand for regulated purchasers.

Renewable energy policy

In 2014, the Ministry of Energy published the Energy Journal, a roadmap for the short term, which provides guidelines for developing the long-term energy policies by 2050. One of the objectives is to eliminate barriers to the development of UREs, so that at least 45 per cent of the electricity generation capacity installed in Chile between 2014 and 2025 comes from such sources, thus fulfilling the goal of a 20 per cent injection of UREs into the electrical system by the year 2025. Among the proposed measures are:[17]

- Support hydropower development with sustainability criteria;
- Encourage the integration of UREs;
- Promote the development of UREs across all economic actors in the consumption market;
- Promote the development of geothermal energy for local development;
- Adapt the operational rules of electrical systems for the incorporation of UREs.

As part of the process of drafting the Energy Policy, the Ministry of Energy is developing a participatory process, called Energy 2050, which integrates the main national actors dealing with different topics of interest. The process includes eight thematic roundtables, among which is the Hydropower Table, which aims to create a participatory approach with regards to the main guidelines that the energy policy should incorporate in the field of sustainable hydropower development for the medium and long term (2025-2050).[18]

The Ministry of Energy recently launched the ‘100 Minihidros’ programme, which aims to have 100 new hydroelectric power plants with less than 20 MW of installed capacity in operation and/or under construction by 2018. In addition, one of the lines of action of the National Water Resources Policy 2015 is to support sustainable energy development and promote the construction of multipurpose plants, primarily for irrigation and energy.[19]

Barriers to small hydropower development

Chile has abundant energy resources, particularly solar, wind, water, biomass and geothermal. However, there are barriers to the development and implementation of non-conventional renewable energies. Regarding hydropower development, in Chile there are both social and institutional barriers. Social barriers include:[16]

- Ownership of water: Hydropower potential is not necessarily perceived as a natural condition of the water resource.
- Use of water: Competition for multiple production and conservation uses of the water in the river basins.
- Asymmetry of information: The information gap between project developers and the community generates mistrust.
- Balance of risks and benefits: Lack of clarity within the community about the risks and benefits associated with hydropower projects. The community perceives the risks, but not the benefits.
- The community at large feels left out of the planning of hydropower development.
- The institutional barriers faced by the SHP sector are:[20]
- Absence of unified criteria of environmental impact assessment for SHP;
- Delays in the legal procedures for the approval of construction permits;
- Water use rights can be monopolized, which limits development or increases costs;
- In most cases, the resource is distant from transmission lines, so the project developer has to invest in the line as well. The high cost of the lines often makes the project economically unfeasible.

2.3.5 Colombia

Ernesto Torres, EPAM DARE

Key facts

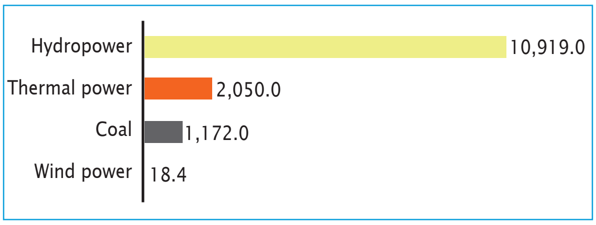
Population	48,329,553[1]
Area	1,240,192 km[2]
Climate	Its equatorial location and the Andes mountain range determine the climactic variations, which are sub-tropical to arid, hot and dry (February to June), rainy, humid and mild (June to November), cool and dry (November to February). Higher altitudes have low average temperatures of below 12°C, while low altitude areas are much warmer, with averages of 18°C-24°C.[2]
Topography	The topography varies per region, from mountainous highlands to low valleys, plains and coast. To the north of the country is the Sierra Nevada de Santa Marta (5,775 m), an isolated massif and the highest elevation of the country.[2]
Rain pattern	Average annual precipitation over land is 500-3,240 mm but varies greatly from year to year and from place to place. The driest region is located in the municipality of Uribia in the Guajira Peninsula, with an average annual rainfall of 267 mm. The Choco region is the wettest, where precipitation exceeds the 9,000 mm per year.[2]
General dissipation of rivers and other water sources	The major rivers include the Magdalena, Cauca, Caquetá, Putumayo, Guaviare, Meta and Atrato. In the mountainous areas, torrential rivers on the slopes produce large hydroelectric power potential and add their volume to the navigable rivers in the valleys.[3]

Electricity sector overview

In 2015, the installed capacity in Colombia was 15,513 MW.[1] The effective capacity by sources was as follows: hydropower 10,919 MW (70.41 per cent); gas and liquid thermal 2,050 MW (19.67 per cent), coal 1,172 MW (7.55 per cent) and wind 18.4 MW (less than 1 per cent).[9] The installed capacity has increased by 930 MW since 2014 (6.4 per cent). This increase is mainly due to several hydropower plants becoming operational such as: Hidrogasamo (819 MW), DarioValencia Samper unit 1 and 5 (50 MW each), the Popal (19.9 MW), the Salto II (35 MW) and the Laguneta (18 MW). The aforementioned increase in the installed capacity is also due to the increase in the capacity of Porce III of 40 MW and the improvement of the thermal plants.[9] The electrification rate in Colombia is 98 per cent, with 100 per cent access in urban areas, in rural areas, this decreases to 90 per cent.[11]

FIGURE 1

Installed capacity by sources in Colombia (MW)



Source: Ministry of Energy and Mines[9]

The Colombian energy industry comprises both public and private players. Private sector involvement was achieved through deregulation in 1990. La Comisión de Regulación de Energía y Gas de Colombia (CREG) is one of the main participants with regulatory oversight.[4] The Colombian National Transmission System, a monopoly by nature, is the middleman between the generators and the traders and is regulated by CREG.[5]

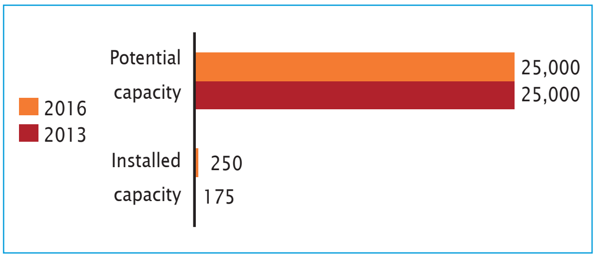
Eleven companies are involved in transmission, of which the government-run company Interconexión Eléctrica S.A. E.S.P. (ISA) controls 83 per cent of the market.[5] The supply of Colombian electricity is based on the National Interconnected System which covers one third of the territory and supplies 96 per cent of the population. Other local systems in the non-interconnected areas provide the remaining 4 per cent of the population mainly residing in the east of the country.[10]

Small hydropower sector overview and potential

Colombia considers small hydropower (SHP) as plants with an installed capacity up to 10 MW. The SHP installed capacity is 250 MW, while the potential is 25,000 MW.[9] Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by 45 per cent, while potential capacity has remained the same.

FIGURE 2

SHP capacities 2013-2016 in Colombia (MW)



Source: *WSHPDR 2013*,[8] Ministry of Mines[9]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Colombia has a total area of 1,141,748 km^2. According to the inventory of the Electric Interconnection S.A-ISA, the theoretical potential hydropower capacity is 93,085 MW, spanning 309 inventoried projects larger than 100 MW. From this total hydropower potential, the economically feasible potential is 7,700 MW.[9]

According to the National Energy Plan, the SHP potential is 25,000 MW. Despite the enormous potential for SHP, only 0.67 per cent of it has been developed. Currently, several regional organizations and regional companies are carrying out portfolios aiming to develop SHP plants.

Currently, Colombia is ranked 4th in Latin America and 11th in the world for Clean Development Mechanism projects registered at the United Nations. According to recent studies, the country has planned to develop 33 SHP projects with a foreseen reduction of greenhouse gas emissions of 2,256,348 tons CO_2/year. Colombia has a total portfolio of 146 projects within the Clean Development Mechanism. The number of SHP plants will rise from 200 to 250 in the short term.

The financing of SHP plants comes from the following sources: multilateral development financing, international and bilateral assistance, NGOs, the private sector, Cleaning Development Mechanism, the national bank with specific funds for renewable energy projects, the Institute of Planning and Promotion of Solutions (Instituto de Planificacion y Promocion de Soluciones) developing renewable energy projects in non-interconnected zones including SHP plants.[4]

Renewable energy policy

Environmental laws concerning general ecological aspects and environmental impacts have been applied in Colombia since the late 1990s. However, all legislation concerning renewable energies was initiated in 2001.[11] Law No. 697/2001 and its Regulatory Decree 3683 of 19 December 2003 provide certain incentives for scholarships, research and development for renewable and alternative energy sources. Since 2002, various tax based incentives have been incorporated into Colombian policy, such as income tax exemptions for biomass and wind generation and exemption from import duties on all equipment related to carbon credits.[5]

Resolution 18-0919 of 1 June 2010 adopted the 2010-2015 Indicative Plan of Action to develop the Program on Rational and Efficient Use of Energy and other forms of Non-Conventional Energy (PROURE). PROURE gives high priority to several lines of action related to the promotion of nonconventional energy sources, including SHP.

Legislation on small hydropower

According to Article 3.14 of Law 697/2001, which establishes and promotes the rational and efficient use of energy as well as the use of alternative energy devices, SHP is defined as the potential energy gained from a hydraulic flow on a certain altitude not exceeding 10 MW of electricity production.[6] In addition, Law No. 697 makes available incentives for research and development in the field of SHP. Legislation surrounding SHP does not include significant financial taxes or subsidies.

However, a few incentives have been implemented such as research grants, tax exemptions and reliability charge exemptions for SHP (less than 20 MW). Moreover, the government's recent engagement to determine the quantity and localities of nonconventional energy sources (Fuentes No Convencionales de Energia) is in the process of producing a multi-year aggregate SHP potential map.[6]

Barriers to small hydropower development

Although SHP plays a vital role in the energy sector, it is not without its problems in Colombia. The main concern surrounding SHP relates back to the El Niño event (1991/1992) and climatic variations which produce lower rainfall that impact energy production. In addition to climatic variations, governments are inclined to reduce concrete SHP promotion strategies and incentives to slow down SHP development and implementation in Colombia due to the fear of high dependency on a climatic vulnerable energy source. Although microfinance institutions (MFIs) are available in Colombia, only three out of the 29 MFIs offer low income loans for micro, small, medium and large borrowers, thus significantly reducing the support available for SHP investors.

SHP growth is also at a disadvantage due to the lack of support systems to identify mechanisms that could be better suited to the characteristics of Colombia, coupled with a deficit in outlined budgeting for scientific research and development. The definition and standardization of technical norms and a lack of rural and urban technical support also hinder the growth of the SHP sector. Moreover, local political instabilities also hinder foreign investment in SHP. Many sites are located in areas where guerrilla activities have taken place.[7]

2.3.6 Ecuador

Alfredo Samaniego Burneo, Ministry of Electricity and Renewable Energy

Key facts

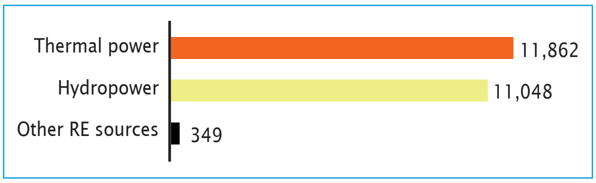
Population	16,216,053[1]
Area	256,370 km[2]
Climate	The weather of the country, due to the Andes Mountains, the influence of the sea and the tropical location, is represented by a great range of climates and weather changes along short distances. In the Andean region, called Sierra, the temperature is related to height. At 1,500-3,000 m the temperature varies between 10°C and 16°C, but in the Oriental, Coastal and Galapagos Islands regions, the annual average temperature varies between 24°C and 26°C, with extremes rarely exceeding 36°C or less than 14°C.[3]
Topography	The country can be defined by the following regions: the Amazon, the Highlands, the Coast and the Galapagos Islands. The highest point is the peak of Chimborazo at 6,267 m.[2]
Rain pattern	Rainfall is variable, depending on location and elevation, ranging between 300 mm on the south coast and 5,000 mm in the Amazon Basin.[3]
General dissipation of rivers and other water sources	The two main water systems are the Esmeraldas River in the north and the Guayas in the south. The Esmeralda begins as the Guayllabamvba River in the Sierra, flowing west before emptying in the Pacific, near the city of Esmealdas. The Guayas forms to the north of Guayaquil, where the Daule and Babahoyo Rivers converge. The Babahayo arises from its tributaries in the Andes. The Guayas basin covers 40,000 km^2.[2]

Electricity sector overview

The National Energy Balance published in 2014 by the Coordinator Ministry of Strategic Sectors reported that the installed electricity capacity was 5,103 MW, with a generation of 23,258.6 GWh (excluding electricity imports from Colombia and Peru) (Figures 1 and 2). Almost all of the households in Ecuador have access to electricity services provided by the 20 electricity distribution companies, achieving an electrification rate of 97.2 per cent.[5,3] The country's electricity is mostly generated by means of hydropower and fossil fuels (natural gas, other fossil fuels, and diesel).[6]

FIGURE 1

Electricity generation by sources in Ecuador (GWh)



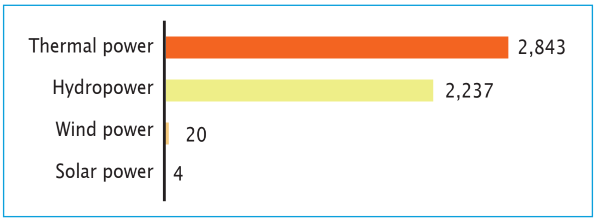
Source: Ministerio Coordinador de Sectores Estrategicos[5]

As changing the energy mix is a national priority, the National Good Living Plan (PNBV-SENPLADES) 2013-2017 set its main target as increasing the contribution of renewable energy up to 60 per cent by 2017, mostly from the exploitation of the hydropower potential of Ecuador. The main electricity consumers in the country come from the industry sector (Figure 3).

In January 2015, the new Organic Law of Electrical Energy of Public Service was issued in Ecuador. This law establishes that the Ministry of Electricity and Renewable Energy (MEER) is the main government entity for the

FIGURE 2

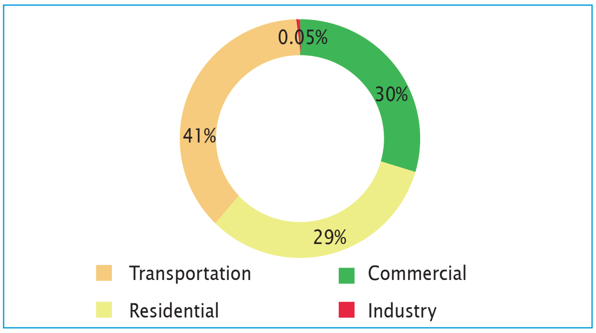
Installed electricity capacities by sources in Ecuador (MW)



Source: Ministerio Coordinador de Sectores Estrategicos[5]

FIGURE 3

Electricity consumption by sector (%)



Source: Ministerio Coordinador de Sectores Estrategicos[5] regulation of and planning for the entire electrical sector of the country. This law also promoted the creation of the Electricity Regulation and Control Agency, replacing the previous National Council of Electricity.[4]

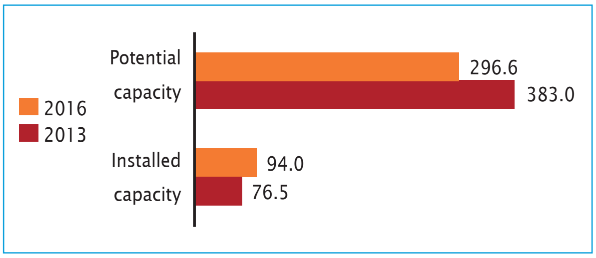
Small hydropower sector overview and potential

Small hydropower (SHP) projects with capacities up to 10 MW that are in operation in Ecuador produce a cumulative nominal power of 94.92 MW. A total of 64 per cent of them are owned by the government and 36 per cent are the property of private companies.[7]

The total electricity produced by SHP in 2012 was estimated at 474.13 GWh. The SHP potential in Ecuador has been identified by several governmental institutions and in different publications since 1997. The remaining SHP potential (for capacities up to 10 MW) is estimated at 296.6 MW and encompasses only those projects to be installed (with economical or technical feasibility) (Figure 4).[7]

FIGURE 4

SHP capacities 2013-2016 in Ecuador (MW)



Source: Consejo Nacional de Electricidad[6]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The former Ecuadorian Institute of Electrification performed in-depth studies related with the vast hydropower potential of the country during the 1970s and 1980s.

Until the national grid was built and came into operation, there were only SHP generation projects that provided electricity to their nearest communities during the 1960s, 1970s and into the 1980s. Once the national interconnected grid became operational, many of those communities were connected to the network and received better quality services. After this, SHP plants were gradually abandoned.

The Ministry of Electricity and Renewable Energy of Ecuador (MEER) and the Association of Mechanical Engineers of the Pichincha's province developed an inventory of all those projects in 2008 and evaluated the feasibility to return them to service. A total of 10 aged SHP projects with an accumulated installed capacity of 9.42 MW were considered eligible for restoration.[8]

In addition, MEER developed design studies of six SHP plants up to 20 MW with the support of the National Pre-Investment Institute:

- Huapamala (5.2 MW);
- Tigreurco (3.44 MW);
- Caluma Pasagua (4.03 MW);
- Infiernillos (20 MW);
- Sardinas (6.65 MW);
- Chinambí (9.9 MW).

Renewable energy policy

The PNBV-SENPLADES 2013-2017 establishes in Objective 11.1 the restructuring of the energy matrix under transformation criteria for the productive matrix, including energy sovereignty and sustainability with an increment in renewable energy production.[9] The plan also points to the importance of taking advantage of the energy potential of renewable sources, mainly hydropower, in the framework of a constitutional right to access water and the conservation of the ecological load flow.

TABLE 1

Energy prices in Ecuador (Regulation No. 001/013), 2011-2013 (US$ cent/kWh)

Type of plants	Continental territory	Galapagos Island
Wind	9.13	10.04
Solar	40.03	44.03
Biomass or Biogas, < 5 MW	11.05	12.16
Biomass or Biogas, > 5 MW	9.60	10.56
Geothermal	13.21	14.53
Hydro < 10 MW	7.17	—
Hydro > 10 , < 30 MW	6.88	—
Hydro > 30, < 50 MW	6.21	—

Source: INAMHI[3]

Moreover, Regulation No. 004/011 issued by the National Electricity Council of Ecuador (CONELEC) in 2011 and valid until December 2012, specified the requirements for renewable energy projects, the prices of the energy depending on the source, the time period during which the prices will be valid, and the preferential dispatch to the grid. These prices (Table 2) will be valid for 15 years for renewable energy projects and the preferential energy dispatch.

TABLE 2

Energy prices in Ecuador (Regulation No. 001/013), 2013-2014 (US$ cent/kWh)

Type of plants	Continental territory	Galapagos Island
Wind	11.04	12.91
Solar	25.77	28.34
Biomass or Biogas	11.08	12.19
Geothermal	13.81	15.19
Hydro < 10 MW	7.81	—
Hydro > 10 ,< 30 MW	6.86	—
Hydro > 30, < 50 MW	6.51	—

Source: INAMHI[3]

Besides that, Regulation No. 001/13 issued in 2013 by the National Electricity Council of Ecuador (CONELEC), which was valid until March 2014, established new prices for energy generated from renewable sources depending on the source, but the preferential period and the preferential energy dispatch did change from the previous Regulation No. 004/011.

Regulation No. 001/13 was modified in 2014 obtaining the following prices for energy generated from non-conventional sources:

TABLE 3

Energy prices in Ecuador for energy generated from non-conventional sources (Regulation No. 001/013; 2014-2015) (US$ cent/kWh)

Type of plants	Continental territory	Galapagos Island
Biomass	9.67	10.64
Biogas	7.32	8.05
Hydro ≤ 30 MW	6.58	—

Source: INAMHI[3]

Today, with the creation of the Electricity Regulation and Control Agency (ARCONEL) the regulations producing incentives for this type of projects are under review and will be updated. Regulation No. 002/13, issued by CONELEC, is applicable to all projects with power not exceeding 1 MW. The developers of the projects will not need a license to operate. Instead they have to register the project with CONELEC after getting a permit from the National Water Resources Secretariat (Senagua) to use the water for industrial purposes, and a certificate from the Ministry of Environment that certifies that the project is not located inside a National Protected Area.

For all projects with power exceeding 1 MW, the project developer must meet the mandatory requirements listed below:[9]

- Company incorporation document, where electrical power generation is considered as the main activity of the company, and registration of foreign companies in the country;
- Certificate of compliance with obligations and legal status issued by the Superintendent of Companies (Superintendencia de Compañías);
- Certified copy of the appointment of a legal representative;
- Payment to the solicitor, equivalent to 200 US$/MW of the declared capacity;
- Feasibility check of the connection to the transmission or distribution system;
- Detailed project proposal, including the general specifications of the equipment to be installed, type of power plant, location, general layout, characteristics of the transmission or interconnection line, if applicable. The information must be presented in hardcopy and digital format.
- Pre-feasibility study of the project, developed by the interested party under the standards established by CONELEC for this purpose. The study must consider the optimal use of the resources, not reduce the potential of other projects having a direct relationship with the new project, and which can be developed in the near future. The information must be presented in hardcopy and digital format.
- Intersection (coordinates) Certification issued by the Ministry of Environment for whether the project is inside the national system of protected areas. If the project is located inside protected areas, it is required to present Authorization for use from the Ministry of Environment.

Barriers to small hydropower development

While hydropower has played a key role in the energy sector of Ecuador for a long period, SHP saw its share in the energy mix decrease as the national grid was extended. More recently, SHP has had resurgence within the mix, and will continue to do so as the abandoned SHP sites are rehabilitated and new installations become operational. Despite this, there are several barriers to the development of SHP in the country: [9,10]

- Lack of tax incentives for private investors. With the new regulations, the investors of renewable energy projects will have a preferred price for each kWh sold to the grid and the certainty that the electricity generated will always be bought by the State. However, there is no definition of a process for qualifying renewable energy projects with other government institutions (SRI, ARCONEL, Ministry of Environment, etc.) to obtain incentives in the tax reporting as stated in the Code of Production on the sustainability of production and its relationship to the ecosystem.
- Large projects receive all the attention. Ecuador has eight emblematic hydro projects under execution, which constitutes the biggest advance promoted and developed by the National Government. The nine electrical projects are: Coca Codo Sinclair (1,500 MW), Minas San Francisco (270 MW), Delsitanisagua (180 MW), Manduriacu (60 MW), Mazar Dudas (21 MW), Toachi Pilatón (254.4 MW), Quijos (50 MW), Sopladora (487 MW). These projects will efficiently and sustainably exploit sources of hydropower by applying clean energy and reducing pollution. These emblematic projects are the perfect example of a country, a new Ecuador, advancing and reaching historic levels of productive, energetic and social development.[1] Thus investment in the construction of these projects has received important contributions of the Ecuadorian State, leaving aside the investment of SHP projects, opening the possibility for private investments and development of small projects. This is because inaccessible sites are expensive to develop since they necessitate the construction of access roads, and transmission lines over large distances. These expenses reduce the indicators for profit and performance of the project, even making some unfeasible.[11]

2.3.7 French Guiana

Marcis Galauska, International Center on Small Hydro Power

Key facts

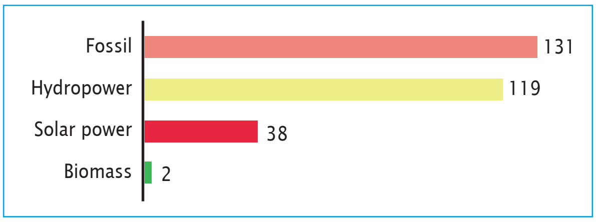
Population	243,000 [1]
Area	83,534 km^2 [1]
Climate	French Guiana has a tropical monsoon climate with a short dry season. It is hot all year round, with cooler nights. The average temperature is 27°C.[2]
Topography	French Guiana is situated on the northeast coast of South America, and is bordered by Brazil to the south and east and by Suriname to the west. The southern Serra Tumucumaque Mountains are part of the eastern frontier while the rest is formed by the River Oyapock. Suriname is to the west along the Rivers Maroni-Itani and to the north is the Atlantic coastline. Along the coast runs a belt of flat marshy land behind which the land rises to higher slopes and plains or savannah. The interior is mostly equatorial jungle. Off the rugged coast lie the Iles du Salut and Devil's Island. The highest peak is Bellevue de l'Inini (851 m).[2]
Rain pattern	The average annual rainfall is approximately 2,500-3,000 mm. The dry season runs from August to December and the rainy seasons are December to January and April to July.
General dissipation of rivers and other water sources	French Guinea is a land of rivers, many of which flow north from the southern mountains. The major ones include the Maroni and Lawa, forming its (disputed) border with Suriname; the Oyapok, forming a long natural border with Brazil; and the Approuaque, Camopi, Mana and Tompok.[3]

Electricity sector overview

Installed capacity in 2014 was 290 MW (159 MW from renewable sources and 131 MW from fossil fuels). Of the total capacity of renewable energy, 119 MW was hydropower, 38 MW solar power and 2 MW biomass (Figure 1). In 2011, 838 GWh of electricity was generated in French Guiana and fed into the grid.[4]

FIGURE 1

Installed capacity in French Guiana (MW)



Source: IRENA[4]

The main player in the electricity generation sector is Électricité de France (EDF), which mainly focuses on gas and hydropower resources. This is done primarily via the Petit-Saut dam, which produces 50-70 per cent of electricity used by French Guiana. Isolated inland towns are powered by large electric generators,[5] and 35 per cent of the population lives in remote villages without an electricity supply.

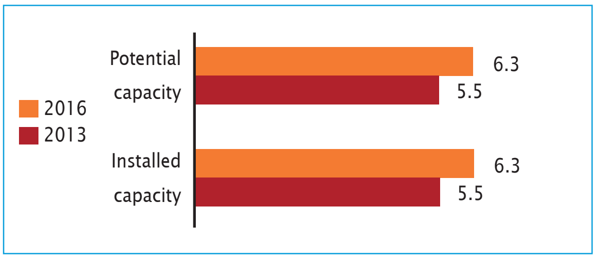
The power system can therefore be characterized by its disparities, fragility and the major role that fossil fuels play in power generation. In French Guiana, electricity costs twice as much to produce in relation to the price it is sold at, and it is subsidized by a national solidarity fund. Even when the inland areas do have a power supply, they suffer from frequent power cuts.[5]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in French Guiana is up to 10 MW. Installed capacity of SHP is 6.3 MW. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, the installed capacity has increased by approximately 15 per cent.

FIGURE 2

SHP capacities 2013-2016 in French Guiana (MW)



Sources: *WSHPDR 2013*,[5] Voltalia[7]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

There are two SHP plants in operation: La Mana with an installed capacity of 4.5 MW, and Saut-Maripa with a capacity of 0.88 MW.[6] In 2014, the company running the hydropower plant on the Mana River received authorization to increase the capacity of its existing hydropower plant from 4.5 MW to 5.4 MW (a 20 per cent increase).[7] From all installed hydropower capacity, approximately 5 per cent is a SHP. Countrywide potential hydropower capacity is unavailable, but sites have been identified on the Mana, Compté and Approuague Rivers, which would make it possible to produce 7-15 MW in the next few years.[8]

Special conditions prevail in non-interconnected power systems in areas described as ‘islands’ by the European Community. These areas do not allow the emergence of a competitive market in the energy sector. Therefore, French Guiana, as an overseas territory of France, has an exemption specially set by the European Community in favour of ‘small isolated systems’. As a result, utilities in French Guiana are not required to separate their network management from their business. EDF continues to integrate all electrical trade to ensure public service. As such, they are committed to generate electricity in competition with other producers and purchase all electricity produced in the territory. They also run 24 hours to ensure a power system balance between customer demand and supply of electricity producers, as well as for transportation and distribution of electricity to all customers.[8]

Renewable energy policy

French law is applicable in French Guiana. However, it can be altered to meet its specific characteristics (on the basis of Article 73 of the Constitution). As a result of this, the Climate Plan to reduce GHG emissions by a quarter by 2050 has also been applied to French Guiana. The National Assembly voted for the Grenelle de l’Environnement (Environmental Forum) law in October 2008. This law applies to the French overseas departments, of which French Guiana is a part. The law states that energy independence shall be achieved by reaching an objective of 50 per cent of final energy consumption in French Guiana, Guadeloupe, Martinique, and La Réunion from renewable sources by 2020, and that exemplary programmes, specific to each department, shall subsequently be developed with the end goal of achieving energy independence by 2030.[5]

French Guiana has a large supply of biomass resources, especially forests. The greatest potential lies in waste from the clearing of agricultural land and logging. A first biomass factory producing 2 MW at Kourou is in operation and some other projects are underway. By 2020, it should therefore be possible to produce over 20 MW from biomass stations, with the advantage of constant levels of production and a guaranteed power output.[8]

For over thirty years now, photovoltaic solar energy has been used to supply remote houses and villages. More recently, solar units have also been used to directly generate electricity for the grid. Within the next few years, 40 MW of capacity is expected to be installed. This is as much as the network can handle without disruption, given that this is an intermittent and fluctuating energy source. The wind in French Guiana is of average strength. Nevertheless, the fact that it is regular and there are no cyclones means that a wind farm of 12 MW with large 2.5 MW wind turbines is a possibility.[8]

Barriers to small hydropower development

The trepidation of a re-occurrence of the El Niño phenomenon plays a crucial role in the government’s decisions to increase dependence on small hydro and as a whole as an energy source. The geographical barrier stems from the specialty of French Guiana, which has a vast landmass with clearly separated coastal and inland areas, coupled with a flat topography, making it more difficult to develop SHP. However, French Guiana is faced with other challenges that strongly hinder the development of SHP, more so than natural climatic variations. The most important factors that impede development are geographical isolation and high demographic growth. Borders with Brazil and Suriname suffer from a lack of control, which results in high crime rates. This prevents foreign investment in the region.[6] In addition, a lack of incentives and technical standardization as well as the low population density makes it difficult and less attractive to develop SHP.[5]

2.3.8 Guyana

Sven Homscheid; Morsha Johnson-Francis, Ministry of Public Infrastructure; Mahender Sharma, Guyana Energy Agency; Horace Williams, Hinterland Electrification Company

Key facts

Population	763,893 [2]
Area	215,000 km[2]
Climate	It has a tropical climate, with temperatures of around 25°C and with little variation throughout the year.[3]
Topography	The terrain is mainly tropical rainforest with flat areas at the coastline and some mountainous areas in the hinterland.[3]
Rain pattern	It has generally high precipitation of 1,500 mm to over 4,000 mm with a pronounced rainy season from May to August and a shorter one from December to January.[3]
General dissipation of rivers and other water sources	Guyana is called the 'Land of Many Waters' due to the abundance of streams, rivers and creeks. The largest waterways are the Corentyne, Berbice, Essequibo and Demarara Rivers. Particularly in the southern and relatively unpopulated part of the country, there are many falls along the rivers while the rivers' gradients decreases towards the more densely populated areas at the coastline.[3]

Electricity sector overview

The electricity system in Guyana is an integrated network on the coast that supplies about 80 per cent of the national population, with various clustered island systems in the Hinterland supplying individual smaller communities and mines. While the electrification rate at the coast is high, most of the Hinterland communities do not have a regular electricity supply.

The country's primary electricity utility is Guyana Power and Light Inc. (GPL), a wholly government-owned, vertically integrated utility company whose license will expire in 2024. In many smaller Hinterland communities such as Lethem, Mahdia and others. Government-owned electricity companies provide supply to the public institutions and households. In some cases, this is provided on a 24 hour basis and in others, for several hours daily.

Electricity is generally generated with diesel and heavy fuel oil generators, with the exception of a small co-generation portion from bagasse and grid connected and off-grid solar systems. In 2013, GPL supplied its customers in the coastal area with 711 GWh of electricity, of which about 53 GWh was from biomass through an independent power producer (IPP) (Figure 1).[1]

GPL's installed capacity in 2013 was about 148 MW, while the available capacity was about 119 MW. Together with the 26 MW HFO based generation capacity added in 2014 and the generators in the Hinterland electricity supply systems, the installed capacity was about 180 MW. The peak demand in the coastal area system is approximately 110 MW.

FIGURE 1

GPL supplied electricity in Guyana (GWh)

Source: Guyana Power and Light Incorporated[1]

Transmission voltage level is 69 kV and feeder and distribution voltage level is generally 13.8 kV or 11 kV, domestic supply voltage is 110 V at a frequency of 60 Hz. The infrastructure in the GPL system is aged and causes frequent service interruptions resulting in many businesses operating off-grid or using their own diesel generators as backup. Also, in the Hinterland, electricity systems supply is rather erratic and mostly only for several hours per day. The combined technical and non-technical losses of the coastal system are approximately 30 per cent.[1]

In the Hinterland electricity systems, various private electricity providers have been established, foremost in conjunction with mining operations that supply the nearby communities with electricity. The Public Utilities Commission regulates the electricity sector.

No effective policy or sector regulation is in place to effectively encourage the participation of independent power producers (IPPs). The Guyana Energy Agency (GEA) is mandated to advise the energy minister in matters related to energy, execute studies, establish energy policies, and regulate the import of petroleum products, but has no general role as electricity or energy sector regulator. Besides the GEA, there is the Hinterland Electrification Company Inc. (HECI) that is attached to the Ministry of Public Infrastructure and is responsible for the electrification of the rural communities. The office of the minister responsible for energy, currently the Minister of Public Infrastructure, issues licenses for IPPs and electric utilities.

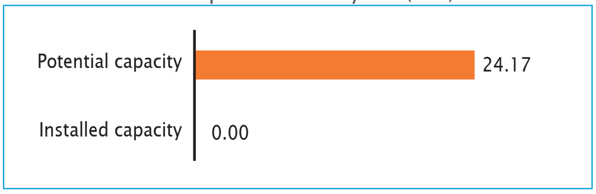
GPL's residential, commercial and industrial rates are US$0.24, US$0.31 and US$0.27/kWh, respectively. Rates in the Hinterland systems are higher with generation costs ranging as high as US$0.50/kWh. Current electricity tariffs are far from cost reflective, as the government subsidizes GPL's operation.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Guyana is up to 5 MW. There is no installed capacity in Guyana, while potential capacity is estimated to be 24.17 MW (Figure 2).

FIGURE 2

SHP capacities in Guyana (MW)



Source: Guyana Energy Agency[4]

The National Energy Policy of 1994 speaks of SHP in the capacity range of 500-5,000 kW.[10] Some sources estimate the country's overall hydropower potential at 7,000 MW, while some estimates are lower. Though Guyana has a track record of hydropower use, to this date, not a single hydropower plant is operational. The Guyana Energy Agency has published on its web page a list of 67 potential hydropower sites that were identified through numerous studies. Based on those studies, estimated SHP potential is 24.165 MW.[4] Various projects were studied through the feasibility stage and some even further.

In recent times, some projects such as the 165 MW Amaila Falls project and the 330 kW Kato project were pursued in an effort of implementation. None of the efforts of these projects have been successful yet.

The Kato project would have served for rural electrification in Region 8, and joint financing from the European Union and the Government of Guyana had been secured. However, the EU has withdrawn its financing offer after a first failed tender. This failure was due to a lack of qualified firms' participation in the tender, and consequent elapsing of the time window for re-tendering.[6]

The Amaila Falls project was supposed to be implemented by foreign investors with financing by the Inter-American Development Bank (IDB). It was to supply the coastal area with electricity. The IDB has withdrawn its financing offer following a market due diligence, an operational assessment of GPL, and financial due diligence of GPL done by a British consulting firm. At the same time, rising prices for commodities and financing have increased the project cost significantly.[6]

Furthermore, the existing—but non-operational—500-kW hydropower plant Moco-Moco, close to the town of Lethem, was financed and built in 1996 with support from the Chinese Government. Unfortunately, in 2003 a landslide destroyed the penstock and a fire in the powerhouse rendered the electrical equipment useless. Studies have been conducted to rehabilitate the plant but no concrete action has followed.

The 1.5 MW Tumatumari hydropower project on the Potaro River was put in operation in 1959 for power supply to a mining company. Afterwards, it was operated to supply the nearby settlements until the plant was decommissioned in the early 1990s. Several actors are currently entertaining efforts to rehabilitate the site, though there has been no tangible outcome yet.

In recent times, hydropower initiatives have been considered and supported by the Government of Guyana. The Guyana Power Sector Policy and Implementation Strategy passed in 2010 outlines the way forward.

After the government stalled the development of the Amaila Falls project due to the associated high-risk levels, the government's interest has reopened towards SHP projects. Therefore, projects like Moco-Moco, Tumatumari, Kato and others of small magnitude are now being reconsidered and support has been sought from international assistance agencies for its implementation.[4]

Due to the natural wealth in fauna and flora, each new project will be scrutinized for its ecological compatibility. Environmentally-friendly projects will be welcomed and have good chances of being approved. However, clear rules are lacking for the environmental and social evaluation of projects. Currently, the Government of Guyana is preparing to attract developers of SHP projects by means of public tendering processes for selected projects. The details of the process have yet to be defined.

There are no special financing mechanisms in place for renewable energy (RE) equipment or projects. There are several local commercial banks and branches of international banks in Guyana, none of which have experience in financing hydropower projects. The Caribbean Development Bank has recently set up a RE and energy efficiency section that seeks to foster increased lending in RE and energy efficiency projects. Several international donor projects from the German Corporation for International Cooperation, the IDB and the World Bank, can be approached for assistance to identify suitable project financing for larger projects. The Government of Guyana has repeatedly stated that they will grant preference to projects not requiring any sovereign guarantees.

Renewable energy policy

The National Energy Policy of Guyana of 1994 contains an outlook from 1994 to 2004. In 1994, the policy already prescribed a mix of energy conservation and a preference for indigenous energy sources over imported fuels. The 1994 policy is outdated and requires modernization, considering the latest technological and other developments. A review of the policy is in progress. There are no feed-in tariffs for electricity generated from RE sources. RE developments are granted tax concessions for 10 years.

The Electricity Sector Reform Act of 1998 mentions the use of renewable and alternative energy but does not explicitly promote the use thereof by creating preferences or other incentives.[7]

In the past, there has been no structured approach to developing the country's hydropower resources. Instead of the government taking a proactive role in developing its resources by tendering concessions or generation capacity portfolios, the government responded to proposals brought forward on the initiative of individual developers. An alternative approach could be public tendering of project sites or concessions, or a generation portfolio with clearly outlined rules for participants in the bidding process. Recently, the cabinet has issued instructions to invite proposals from interested groups for RE supply for the Bartica community, Lethem (Moco-Moco) and other identified communities. However, the degree to which the government will support the financing arrangements is not yet clear.

Potential developers see themselves confronted with obscure processes for obtaining the various licenses instead of clear procedures and rules for the application and project development process. This results in uncertainty for developers regarding the application duration, application cost and likely outcomes. This applies for planning licenses, operating licenses, environmental permits and any other applicable permits. The Government of Guyana has introduced a web-based platform for investors[8], but it is still in its development stage. Developers typically put forward high expectations regarding revenue and payback time, which the projects rarely are able to satisfy. On the other hand, the government also remains unwilling to grant sovereign guarantees, which would make it easier and cheaper for developers to mobilize financing. Here, both parties need to move from their standpoint towards realistic expectations.

Barriers to small hydropower development

Technically, the great distances between hydropower sites and load centres and the difficult access into the Hinterland are the main barriers for the development of hydropower. In most cases, the construction of expensive access roads has to be included into the project budget. This jeopardizes the viability of projects. In addition to this, 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 power demand.

Hinterland villages face the problem of clustered settlements with large distances between villages and even individual houses, resulting in high costs for the connection of households to the electricity supply. The vast hydropower potential in Guyana requires strong administrative and procedural structures to channel development to a successful outcome.

2.3.9 Paraguay

Nathan Stedman, International Center on Small Hydro Power

Key facts

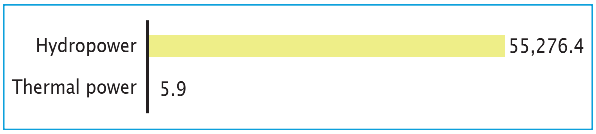
Population	6,552,518 [1]
Area	406,750 km^2
Climate	The climate is sub-tropical in the Paraneña region and tropical in the Chaco region with an average temperature of 22°C. May to August is the winter season, with July being the coldest month (17°C). October to March is the summer season, with January being the warmest month (29°C). Day temperatures reaching 38°C are common.[3]
Topography	The two main regions in Paraguay are the Paraneña region, characterized by plateaus, rolling hills, and valleys, and the Chaco region, with an immense piedmont plain. The highest point is in the eastern mountains, close to Brazil, at 700 m.[2]
Rain pattern	Rainfall varies per region and per season. The Paraneña region receives an average of 1,270 mm of rain annually while some areas receive upwards of 1,800 mm. The Chaco region is considerably drier, with some areas receiving only 400 mm per annum.[3]
General dissipation of rivers and other water sources	Río Paraguay and Río Paraná are the two main watercourses in the country. They define most of the borders and their basins provide all of the drainage. The major tributaries entering the Río Paraguay from the Paraneña region (such as the Río Apa, Río Aquidabán and Río Tebicuary) descend rapidly from their sources in the Paraná Plateau to the lower lands. The major tributaries of Rio Parana, which originate in Paraguayan territory, are the Acaray, Monday, Piratiy and Carapá. All of these possess important hydroelectric potential.[2,3]

Electricity sector overview

Paraguay is a country with a wealth of unique natural energy, particularly hydropower, and is regarded as one of the largest exporters of energy and the largest exporter of hydroelectricity in the world. Despite this, the country has domestic supply issues and is currently investing in improving the efficiency of the National Interconnected System (NIS), which covers roughly all of the territory.[4]

FIGURE 1

Electricity generation in Paraguay (GWh)



Source: IJHD[5]

Total electricity generation in 2014 was 55.28 TWh, of which 99 per cent was from hydro and the rest from thermal.[5] Installed capacity in 2014 was 8,834 MW. Only 24 MW was from thermal plants. Most of the capacity comes from the bi-nationally operated dams. 7,000 MW derive from the Itaipú dam jointly operated with Brazil, and 1,600 MW are from the Yacyretá dam jointly owned with Argentina (while 210 MW are from the solely Paraguayan owned Acaray dam).[7] All of the electricity generated that is not consumed domestically is exported to the markets in Brazil and Argentina (roughly 82 per cent).[4]

The Administracion Nacional de Electricidad (ANDE) is a state-owned utility and controls the electricity market. It operates more than 3,000 km of transmission lines in the NIS and 1,000 km of distribution lines. In addition to the ANDE network, there are also some private regional networks connected to the national grid.[4] As of 2013, the national electrification rate was 99 per cent, with access in rural areas at roughly 98 per cent.[8]

The tariffs for the electricity sector in 2011 were at a national average of roughly US$0.07/kWh, nearly half

TABLE 1

Electricity tariffs in Paraguay

Type	US$ cents/kWh
Residential	8.64
Commercial	8.19
Industrial	5.75
General	6.53
Government	6.26
Street Lights	8.99

Source: Columbia University[7]

of what neighbouring countries' tariffs were set at (US$0.14/kWh average).[7] Tariffs are determined by the president of ANDE, as per Law 2199/03 (Article 16).[4]

During the period from 1999-2012, system losses in the NIS increased from 21 per cent to 30.9 per cent. The increase is attributable to the 220 kV lines in the network. Without 500 kV transmission lines, the current system is running over capacity. This results in frequent blackouts and shortages during inclement weather, which in turn can affect commercial activities by as much as 2 per cent of revenue. In 2011, there were 16 power cuts with an average duration of 10 hours.[7]

Another cause of the increasing inefficiency of the NIS is the structure of the energy sector. The Vice Ministry of Mines and Energy decides the national energy strategy. However, this is often circumvented by the organizational and financial strength of ANDE, which can bypass the Ministry in the execution of ANDE's Master Plan and other activities. Moreover, there is little incentive for ANDE to address the issue of system-wide losses, as any surplus in operation is transferred to the Ministry of Finance. Therefore, higher margins will not benefit the utility company.[7]

ANDE's 2012-2021 Master Plan outlined the strategy of upgrading the 220 kV transmission lines to 500 kV, due to the existing lines creating losses of an estimated US$226 million annually. The Master Plan will cost an estimated US$2.5 billion to complete. As of 2015, the government has secured 47 per cent of this from various international organizations (Inter-American Development Bank, Corporación Andina de Fomento and others).[7]

Another development worth noting is the proposal by Rito Tinto Alcan (RTA) to invest a US$4 billion aluminium smelter in Paraguay. The smelter is expected to utilize some 1,100 MW of electricity, or nearly half of peak demand in 2011 (2,137 MW).[7]

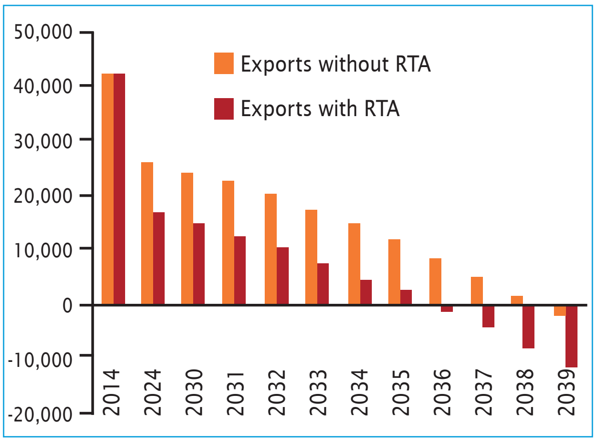
Peak demand in 2020 is projected to reach 4,260-4,847 MW. By 2040, electricity demand could reach 59,713 GWh. Meanwhile, Argentina and Brazil are also expected to see a growth in demand. Some estimates have Brazil almost tripling demand by 2030.[7]

Several new hydropower projects have been planned by ANDE to meet the increased demand. The largest of these projects is the Corpus Christi dam, a joint project with Argentina that will have an installed capacity of 1,256 MW and is expected to be operational by 2030. With these new plants, generation is expected to reach 64,273 GWh by 2030 (compared to 55,282 in 2014).[7]

Despite these efforts, if the RTA project is implemented, the country's electricity exports are expected to decline over the next two decades, and cease by 2036 as demand surpasses supply. Even if the RTA project is not realized,

FIGURE 2

Electricity exports with and without RTA



Source: Columbia University[7]

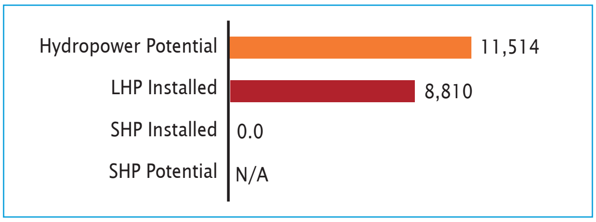
electricity exports will cease by 2039 if generation does not continue to increase (Figure 2).[7]

Small hydropower sector overview and potential

Paraguay has an enormous amount of hydropower potential, greatly exceeding the current installed capacity. The country has an estimated 130 TWh of hydropower potential, with technical and economically feasible potential near 101 TWh annually.[7]

FIGURE 3

Hydropower in Paraguay, 2016 (MW)



Sources: OLADE,[4] Columbia University[7]

Currently there is no small hydropower (SHP) plant in operation, nor is there any proposed plan to install SHP. Feasibility studies performed and data published relate to hydropower in general, therefore data pertaining to SHP (less than 10 MW) is unavailable at present.

However, it can be deduced that there exists a real and untapped potential for SHP within the country. As demand continues to grow, the installation of new large hydropower plants will cover most of the increase in the short term, yet exports of hydro generated electricity will likely decrease. Adding SHP to the NIS could not only aid in domestic generation, but could potentially bring access to electricity to the remaining 2 per cent of the population that is lacking, while also allowing the government to continue the revenue flow from electricity exports.

Renewable energy policy

As 99 per cent of electricity generated in Paraguay is from hydropower, policies related to the NIS are in essence renewable energy (RE) policies. The ANDE 2012-2021 Master Plan to reduce losses in the NIS and increase efficiency also includes the addition of new hydropower plants.

ANDE was the monopoly controller of the electricity market until 2006, when Law 3009/06 was adopted. The law opened the market to independent power producers to generate and transport electricity for domestic consumption or export. The law applies to all RE resources with the exception of hydropower plants larger than 2 MW. Despite the opening of the market, only a handful of proposals have been submitted currently.

For any new projects, Law 2009/06 is also applicable as it established that access to the grid is non-discriminatory. Environmental Impact Assessments (EIA) are required by Law 294/93. Meanwhile Law 352/94 regulates protected areas.

Regarding solar energy, Law 3557 approved an EU project to provide solar PV to 45 centres while Decree 6417 provided solar to 35 isolated communities.[9]

Barriers to small hydropower development

With the vast hydropower resources in the country, ANDE produces a surplus of electricity, which is exported to Brazil and Argentina. Currently there are no incentives for ANDE to alter the operation of the NIS and the generation of electricity. Although legislation allows for independent power producers and public-private partnerships within the energy sector, very few projects have been proposed. It is expected that independent power producers will not begin to enter the market until demand increases. However, SHP could be useful in times of unusual peaks, as well as reaching remote rural communities that still lack access to electricity. If the RTA project is realized, this could greatly impact revenue from exporting hydro produced electricity as well as domestic supply, SHP could help to offset those losses.

2.3.10 Peru

Jorge Reyes and Leo Guerrero, University of Piura

Key facts

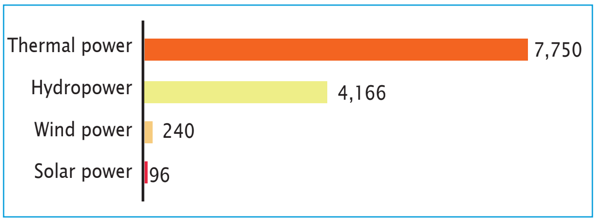
Population	31,155,263
Area	1,285,215 km^2
Climate	Peru has a diverse climates and microclimates, including 28 of the 32 world climates. Such diversity is conditioned by the presence of the Andes Mountains, the cold Humbolt Current and El Niño. The temperature varies from below 0°C to 40°C.[13]
Topography	Peru is divided into three contrasting topographical regions: the coast, the highlands and the eastern rainforests, ranging from 0 m on the coast to 6,768 m above sea level in the highlands.[13]
Rain pattern	In the northern coast the summer rainfall total rarely exceeds 200 mm, except during the severe El Niño events, which can provoke major flooding with precipitations higher than 4,000 mm. In the central and southern coasts the rainfall is scarce with a total range between 10 mm and 150 mm.[13]
General dissipation of rivers and other water sources	The main rivers in Peru are the Amazon, Madre de Dios, Putumayo, Napo, Maranon, Huallaga and Apurimac.[13]

Electricity sector overview

The installed electrical capacity in Peru in 2015 was 12,251 MW; approximately 63 per cent of the total installed capacity was derived from thermal power, 34 per cent from hydropower, and 3 per cent was from solar and wind power (Figure 1).[14] Total net electricity generation was estimated to be 48,066 GWh, with 23,300 GWh produced from hydropower.[14] For the past ten years, generation has increased due to a greater use of natural gas (13 per cent increase annually).[7]

FIGURE 1

Electricity generation by source in Peru (GWh)



Source: Ministerio de Energía y Minas[7]

The electricity sector in Peru has been shaped by public sector investment and the active participation of the private sector. In the early 1990s, the government issued a series of laws to promote private investment, highlighting the electricity sector as a national interest. The reform of the electricity sector started in 1992 with the promulgation of the Electricity Concessions Law. This law set the legal framework for the activities in the electricity sector. The general objective of this law is to promote a price system for greater economic efficiency by setting up a tariff for end-users. The tariff takes optimal usage of available energy resources into account. Generation, transmission and distribution utilities were unbundled as a result of this law. It also engaged the private sector in these commercial activities.[2]

In 2006, the Law for Efficient Generation Development came into force to complement the Electricity Concessions Law. The Law for Efficient Generation Development aims to guarantee efficient electricity generation, reducing the vulnerability of the Peruvian electrical system to price volatility and long blackout periods. It also provides the assurance of a competitive electrical tariff to consumers. In addition, it establishes two new different types of transmission systems, one for supplementary transmission and one for guaranteed transmission.

Sustainable rates of economic growth over the last decade have had a positive impact on poverty reduction. Private investment in the power sector in 2011 constituted 93.9 per cent of total investments, while the government invested 6.1 per cent. Private investment projects for generation accounted for 97.7 per cent of the total and 65.8 per cent for distribution. The public sector invested the remaining 34.2 per cent, especially in rural electrification. In 2011, extreme poverty was at 6.3 per cent, and was particularly concentrated in rural Peru and more specifically the Sierra region.[3] Studies have shown a strong correlation between poverty levels and access to basic services including electricity. The government is making significant efforts to raise access to electricity in rural areas under its social inclusion strategies. In this way, renewable energy (RE) technologies (especially solar, small hydro and biomass) could play an important role in satisfying energy requirements in rural Peru.[4]

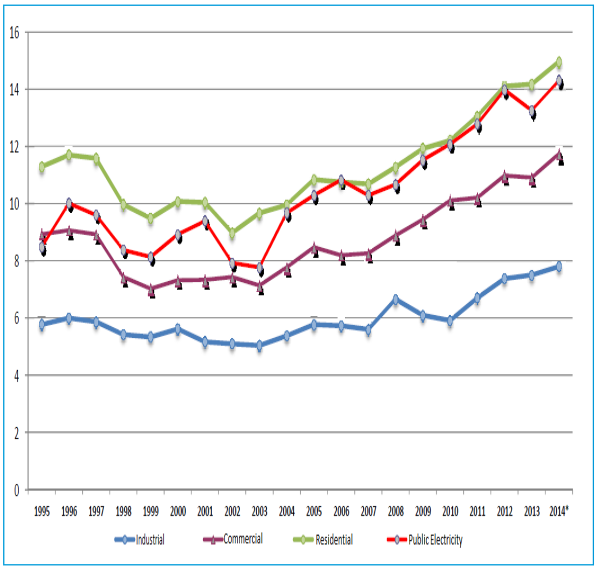
"The Peruvian electricity market has matched the country's economic growth and development. According to Ministry of Energy and Mines (MINEM), the total installed capacity has increased a 98 per cent in the last ten years with the electricity sector growing from 6,200 MW in 2005 to 12,251 MW in 2015.[7] Demand has increased rapidly, but the expansion of grid infrastructure has in the past not matched the power demand requirements. This means that transmission is at present operating almost at maximum capacity, particularly in the country's southern and northern corridors. This adds to the challenges of raising power generating capacity in these areas, which are expected to become the new poles of development. To relieve this situation, investments in grid infrastructure are now under way. While almost all regions are interconnected to SEIN, there is a clear heterogeneity in the regional electricity market. This situation is explained by the differences in the availability of generation sources, watersheds usable for the generation activity or access to pipelines transporting natural gas; the presence of SEIN transmission networks; location and heading of the main economic activities; population density or number of customers; among others.

The central part of the country has advantages over the aforementioned criteria, where sector development in the regions focus largely on installed capacity of hydro and thermal efficient generation (Camisea natural gas), which include areas such as Lima (4,847 MW), Huancavelica (1,024 MW), Callao (610 MW) and Junin (446 MW) in 2013. In contrast, regions in which the main economic activities take place in remote areas, such as mining in the Sierra and exploitation of hydrocarbons in the jungle, have a greater presence of auto-generation units. These differences are also expressed in the consumption regional power: in 2012, Lima accounted for 44.5 per cent of total sales, 56.6 per cent of sales was to regulated customers and 29 per cent of sales was to free customers. Regions with major mining and industrial operations, namely Arequipa, Ica, Moquegua and Ancash, have a concentration of the free customers outside the capital (Figure 2).

The government regulates transmission and distribution tariffs. In 2014, prices for electricity averaged from US$0.072/kWh to US$0.13/kWh. These tariffs vary among different economic sectors. Figure 3 demonstrates

FIGURE 2

Price for electricity by economic sector



Source: Ministry of Energy and Mines[7]

that public electricity is the most expensive, while the industrial sector uses the most electricity.[7]

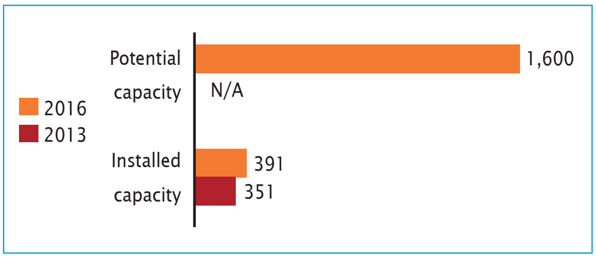
The main problems with RE resources, is that the plants that operate with such technologies can create individual ecological problems. Additionally, there are a number of drawbacks that limit its economic cost competitiveness. These include:

- High investment costs: The capital cost for the technology is significant, while that for wind and solar is becoming more competitive.
- Variability: Solar and wind resources are unpredictable and cannot be dispatched, thus exhibit low load factor.[7]

Peru has a total electrification rate of 90.3 per cent and a rural electrification rate of 70.2 per cent.[7] The National Rural Electrification Plan 2013-2022 provides strategic direction to provide access to electricity to 6.2 million people by 2022. There are efforts to increase access to energy via auctions for solar photovoltaic systems, grid extension, mini-grids with hydro, solar and wind.[4]

FIGURE 3

SHP capacities 2013-2016 in Peru (MW)



Source: *WSHPDR 2013*,[12] the World Bank Group[5]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Small hydropower sector overview and potential

Peru has significant small hydropower potential, defined as plants with capacity less than 20 MW, which is conservatively estimated at over 1,600 MW. Unfortunately, there is no solid basis for estimating the technical potential of SHP in Peru because of the lack of inventories of such resources. The total installed capacity for all SHP plants, including grid connected and isolated plants under 20 MW is 391 MW,[15] with 251.1 MW connected to the national grid.[16] In 2015, the installed capacity for grid connected plants up to 10 MW was 112.8 MW.[16] Between the 2013 and 2016 *World Small Hydropower Development Reports*, installed capacity up to 20 MW has increased, while potential has been reassessed due to more conservative estimates of economically feasible potential.

MINEM, supported by the Advisory Committee, have set a goal of preparing a proposal to institutionalize the process of energy planning in Peru. MINEM has proposed three central hypotheses. First, it is considered that the national economy will grow by an average 4.5 per cent annually and in a more optimistic scenario, 6.5 per cent. This is a situation that would confirm that the reserves and infrastructure are sufficient to continue to endure high rates of growth. Secondly, it is postulated that the level of energy prices in the domestic market will follow the trends in global energy prices, with the exception of gas. The price will reflect current contractual conditions and incorporate more lots with prices to match the offer and domestic demand.[4] Thirdly, MINEM proposed the availability of resources, based on the fact that currently production has reserves and untapped resources of hydropower, natural gas and non-conventional RE, all sources are suitable and sustainable for the expected economic growth.[7]

The most fundamental constraint to developing the country's hydro potential has been the low tariff faced by generators, which is a consequence of the low domestic price of natural gas. Almost all new power generation installed in Peru during the last decade has been based on low priced natural gas from the Camisea Field. The price of Camisea gas delivered to plants near Lima is estimated at US$2.15 per BTU, which means an average price for gas-based generation of around US$0.035/kWh. Given that Peru will shortly become an LNG exporter, the opportunity cost of natural gas is now linked to international prices.[5]

Development of SHP has not been financially viable because the financial cost of generation was set by the cost of gas-based generation at a lower price for natural gas from Camisea. At an average price for gas-based generation of US$0.035/kWh, a 17.5 per cent financial rate of return (FIRR) on equity, a 10-year loan period and a 70 per cent load factor, the maximum capital cost that is financially viable for a hydro project is around US$850/kW. When carbon finance and the increasing cost of oil are taken into consideration, the allowable capital costs increase to around US$1,000/kW. Nevertheless, greenfield SHP projects cannot be built at such low capital costs.[6] Unlocking the significant potential of SHP in Peru would require either the removal of the low price for natural gas from Camisea or a preferential tariff for SHP that reflects the economic opportunity cost of gas powered generation. Using a generation price based on the economic opportunity cost of gas generation of US$0.056/kWh and the same assumptions for FIRR, loan tenor and load factor, the allowable capital cost for SHP increases to US$1.4/kW. This is a level that would make many SHP plants financially viable in Peru, even with recent increases in hydro construction costs.[6]

Renewable energy policy

The regulatory framework for the promotion of renewable energy has evolved since the enactment of the Electricity Concessions Law and its Regulations (1993, 1994), which created the electricity market and set its institutional arrangement. The Law on Efficient Generation (2006) promotes long tenders and contract terms as a means to support investment in large-scale generation (large hydro and other conventional technologies). Legislative Decree No. 1002 (2008) declares, out of national interest and public necessity, the development of electricity generation from renewable resources.[8] It establishes a national priority the promotion of renewable energies; defining Renewable Energy Resources (RER) as the sources of non-conventional renewable energy: solar, wind, geothermal, biomass, and hydropower up to 20 MW (Hydro RER).

The Government promotes electricity sales of RER through auction, posing as the current target level of penetration RER, excluding small hydropower projects. The main incentives offered are: the priority access to the office of System Economic Operation Committee (COES) and purchase of energy produced; priority access to transmission and distribution networks; and stable long term rates determined by auction.[9] Auction Bases are approved by the Ministry of Energy and Mines; the Supervisory Commission for Investment in the Energy and Mining Sector (OSINERGMIN) leads the auction, fixes the maximum prices and determines the premiums through annual assessments.

Legislation on small hydropower

It has been difficult to attract financial support for green energy projects. To rectify this, the MINEM approved some benefits for SHP projects under 10 MW installed capacity:[6]

- All of the permitting process is carried out at the regional level with local authorities, where the project is located;
- No Environmental Impact Study (EIA) is required. It is sufficient to file a non-environmental impact commitment document.[7]

The benefits of SHP projects in development and under construction are such that even some of the bigger power generation companies are investing in them in Peru. In some cases, larger companies even buy them as greenfield projects at the permitting stage or by acquiring hydropower power plants in production. They proceed to invest additional funds, earmarked for improvements. In some cases, water storage facilities are added to the projects to enhance production. This is done without altering water use permits and by seeking support from the local stakeholders, who have already seen first-hand the benefits of having a local power plant operating and know that they can also benefit from the water regulation facility.[3]

Barriers to small hydropower development

Peru is rich with RE resources: solar, hydro, biomass, biogas, wind, and geothermal, but only a small fraction of this potential is currently used.[10] While investment in the RE sector has seen an increase, there are some barriers to developing new RE projects, including SHP:

- Investment costs: All have different costs and depend on technology and resources.
- Operation and maintenance cost: All energy resources require moderate human resources training.
- Transport and construction infrastructure for most energy resources is limited.
- Environmental: Most RE projects have at least minimal to moderate environmental impact during construction phases.
- Financial: Bankers' limited knowledge of the RE market and profitability, credit officers' limited knowledge about RE project evaluation and regulations. Banks may need external technical support to assess RE investment projects and technical assistance component is required to credit lines.[11]

2.3.11 Uruguay

Martin Scarone, Ministerio de Industria, Energia y Mineria

Key facts

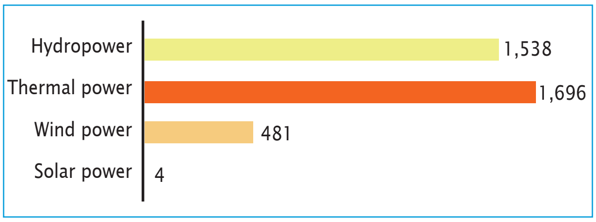
Population	3,407,000[1]
Area	176,215 km^2
Climate	Uruguay has a temperate climate with cold winters (June to September) and hot summers (November to March). The average temperature in January is 24°C. In July, it is 10°C.[1]
Topography	The landscape features mostly rolling plains and low hill ranges (cuchillas) with fertile coastal lowland. The highest elevation is roughly 500 m.[1]
Rain pattern	Uruguay has a rainy climate without a dry season. The rains are characterized by their extreme irregularity and annual variability. The annual precipitation varies between 1,100 mm in the south of the country and 1,600 mm in the north.[1]
General dissipation of rivers and other water sources	Uruguay is surrounded by rivers on three sides. In the north the Cuareim River forms its border with Brazil for more than 280 km. On the southern border is the Río de la Plata, the large estuary formed by the union of the Uruguay and Paraná Rivers. The Uruguay River, from which the country took its name, forms the western boundary and is by far the largest and most picturesque of the country's rivers.[1]

Electricity sector overview

In 2014, the energy generated in Uruguay was approximately 13,008 GWh. Of the total generated, 3,125 GWh came from hydropower plants.[3] In 2014, the installed capacity was 1,538 MW of hydropower plants, 1,696 MW of thermal plants that run on fossils fuels and biomass, 481 MW of wind energy, and almost 4 MW of solar energy. Regarding the installed capacity by energy source, the most significant share in 2014 corresponded to renewable energy with 66 per cent (hydropower, biomass, wind, solar), whereas non-renewable energy accounted for 34 per cent of total capacity (gas oil, fuel oil, gas natural).[2]

FIGURE 1

Installed capacity by sources in Uruguay in 2013 (MW)



Source: Secretary of Energy[2]

The consumption of energy in 2014 was approximately 10,350 GWh.[10] In 2013, there was a 51 per cent increase in hydropower consumption of electricity production, in comparison to 2012, while fossils fuels decreased 50 per cent (both fuel and oil).[2] The electric grid in Uruguay consists of 770 km of 500 kV lines that are connected from Salto Grande through the Rincon del Bonte dam to the main consumer centre in Montevideo. The national grid also includes a branch to San Carlos City, located in the south-east of the country. There are 3,549 km of 150 kV lines connecting the power generation plants with almost all the major cities and main load centres.[3]

In Uruguay, electricity generation is open and every generator can connect with the public electric grid. Private generation companies must sign contracts with the electricity utility Administración Nacional de Usinas y Trasmisiones Eléctricas (UTE) or sell at the spot price. UTE is the only distribution and transmission operator in Uruguay. The electrification rate in Uruguay is 99 per cent. The average household electricity tariff is US$0.19 for 600 kWh per month.[4]

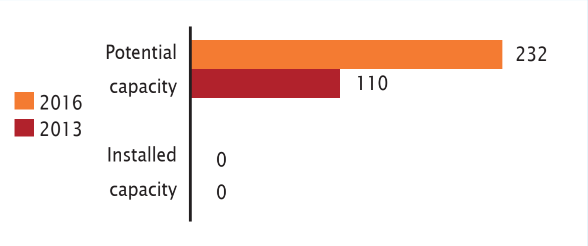
Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Uruguay is plants with an installed capacity up to 50 MW. Mini is defined as 100-1,000 kW, micro is defined as less than 100 kW and pico less than 5 kW.[9] SHP installed capacity remains 0 MW, while potential is 232 MW.

Regarding SHP potential, there are three kinds of sectors that have been studied: SHP sites only for generation, SHP sites that can be added to a dam used for irrigation and hydropower sites that can be added to a dam that can be used for irrigation but have not yet been developed.

FIGURE 2

SHP capacities 2013-2016 in Uruguay (MW)



Sources: *WSHPDR 2013*,[8] IMFIA[7]

In the case of small hydropower sites only for generation, the study was carried in all the rivers except for the rivers on the borders and the Black River. Up to 70 feasible sites were identified, all of which would not cause environmental damage or draughts in the surrounding areas. These 70 sites have a potential capacity of 232 MW. From these 70 sites, five were selected in order to study installed capacity, energy generation, environmental impact and economic and financial feasibility. From these five projects, only the projects of Arerengua, Arapey and Yerbal were determined to be economically feasible (including the price of the land) with the energy prices that are being paid currently (Table 1).[7]

TABLE 1

Potential studied SHP sites in Uruguay

River	Potential capacity (MW)	Capacity factor (per cent)	Estimated energy generation per year (MWh)
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: IMFIA[7]

From the more of 1,331 irrigation dams already built in Uruguay, 20 damns were selected to carry out a generation viability studies. Moreover, economic and technical feasibility studies were carried out. The average capacity for each damn is 100 kW.

Renewable energy policy

In the Uruguayan 2005-2030 National Energy Policy, the government has set a RE goal of 50 per cent native renewable sources in its primary energy matrix by 2015. Among other measures to accomplish this, non-traditional RE sources (wind, biomass residues and micro-hydraulic generation) will contribute 15 per cent of the total generation. It has also set up the target of reaching 90 per cent of RE in its electric matrix by 2030.[4]

Legislation on small hydropower

In 2007, the Government of Uruguay offered 20 MW to be added to the grid from SHP, but no private investors applied. The government still plans to develop SHP to promote rural development and to increase the number of irrigation dams. Article 47 of the Uruguayan Constitution outlines the utilization of water and defines the right to water and sanitation as a fundamental human right. In accordance with the requirements established by Law No. 16466 of Environmental Impact (1994) and enabling regulations established in regulatory code No. 349/005 (Evaluation of Environmental Impact), an environmental permit must be requested for hydropower projects with capacities exceeding 10 MW or water flows higher than 0.5 m^3/s. Law No. 16 906 on the Promotion and Protection of Investments provides a framework for encouraging investments in the country, upon approval by the designated commission. Enabling regulation No. 354/009 promotes the generation of electricity from non-traditional renewable sources and grants the exemption of a significant percentage of the income tax for electric generating companies at the start of business, with subsequent reductions in the following years. Decree 2/2012 establishes tax benefits that may be granted (income tax deduction according to amount of investment, tax exemptions, VAT returns).[6]

Barriers to small hydropower development

Currently there are no SHP plants connected to the national grid, therefore, the approval process and duration as well as the associated risks with lengthy investment periods related to SHP projects are relatively unknown. As no projects have yet been completed, there is a fundamental gap of experience and knowledge between planning and implementation, operation and maintenance for SHP.

2.4 Northern America

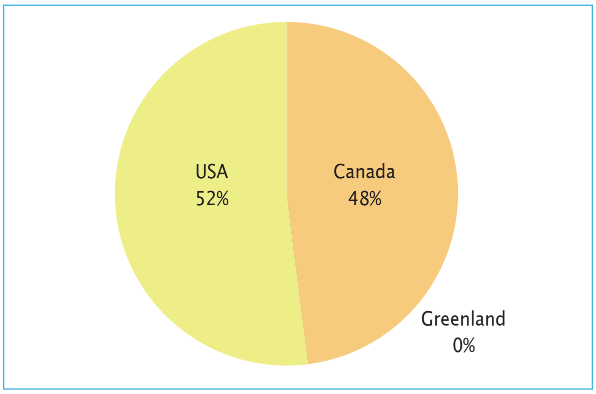
Johan G. Grijsen, Hydrology and Climate Risk Assessment

Introduction to the region

North America comprises five countries and territories: Bermuda, Canada, Greenland, Saint Pierre and Miquelon, and the United States of America (USA). Of these, only Canada and the USA are endowed with large small hydropower (SHP) potential. Canada, Greenland and the USA cover exceptionally large swaths of land with varying climates.

FIGURE 1

Share of regional installed capacity of SHP by country

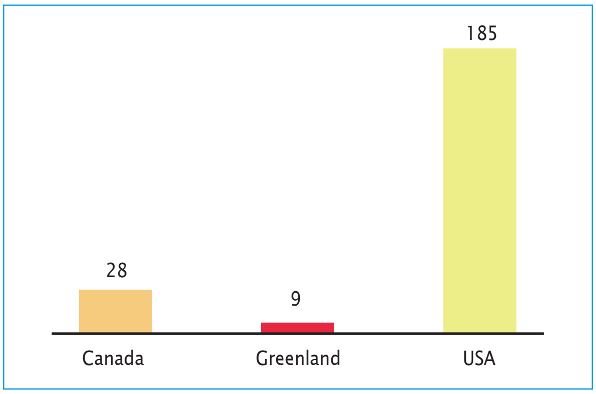


Source: *WSHPDR 2016*[7]

Greenland is largely covered by an icecap of up to 3,200 m thick, with an estimated volume of 1.7 million km^3 (2,166,086 km^2 or 81 per cent of its total land area is covered by ice).[1] The icecap covers all but a narrow, mountainous, barren and rocky coast, in an arctic to sub-arctic climate. The Canadian territory covers 9,985,000 km^2 and possesses climate conditions ranging from mild temperate on the west coast to sub-arctic and arctic in the north of the country.[2] The interior provinces are dominated by the relatively flat Great Plains and Canadian Shield, bordered by mountain ranges on the western and eastern sides of the country. Nine per cent of the territory consists of 8,500 rivers and 2 million lakes.[3] The USA, with its large size (9,826,675 km^2) and huge geographic variety,[4] includes most climate types, varying from a tropical climate in Hawaii and Florida to a sub-arctic or polar climate in Alaska, a semi-arid climate in the Great Plains west of the Mississippi River, arid conditions in the Southwest and a temperate climate elsewhere. Annual rainfall varies between over 1,600 mm in Hawaii and just 241 mm in Nevada.[5] The country's topography is dominated by large central plains with hills and low mountains in the east and higher mountains in the west. The nation's largest river systems based on flow volume are the Columbia River in the north-west and the Mississippi River in the south-east.

FIGURE 2

Net change in installed capacity of SHP (MW) for Northern America, 2013-2016



Sources: *WSHPDR 2013*,[9] *WSHPDR 2016*[7]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Around 60 per cent of all electrical energy (GWh) generated in Canada (in its western and eastern provinces with mountain ranges) and in Greenland is hydro-energy (Table 1). On the other hand, the USA depends predominantly on fossil fuels (coal and natural gas) and nuclear energy (85.5 per cent). Non-hydro renewable energy (RE) resources provide 6.9 per cent while hydropower provides 6.2 per cent of the total energy.[6] Recently, natural gas generation has been growing rapidly, along with wind and solar energy.[14] Hydropower, as a percentage of total electricity generation, has been relatively stable in the USA since 2007.[8]

TABLE 1

Overview of countries in Northern America (+ % change from 2013)

Country*	Population Dec 2015 (million)	Rural population (%)	Electrification access 2015 (%)	Electrical capacity (MW)	Electrical generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Canada	36 (+2%)	19	100	127,800 (-2%)	610,700 (+4%)	75,800 (+1%)	387,100 (+11%)
Greenland	0.058 (+4%)	14	100	140 (0%)	541 (+16%)	91.3 (+32%)	317 (+13%)
USA	322.8 (+2%)	14	100	1,003,000 (-4%)	4,093,100 (-1%)	80,000 (+2%)	252,580 (-2%)
Total	**358.858 (+2%)**	**14.5**	**100**	**1,130,940 (-3%)**	**4,704,341 (0%)**	**155,891.3 (+2%)**	**639,997 (+6%)**

Source: Various[7,9,10,11,12,13,14]

Small hydropower definition

The definition of SHP in Canada is up to 50 MW of generating capacity.[15] According to some sources, this is 10 MW to 15 MW. In the USA, there is no widely accepted definition, but for this report the threshold is set at an installed capacity of 10 MW, i.e. the largest capacity qualifying for a SHP exemption at the Federal Energy Regulatory Commission of the USA. In Greenland the threshold is also 10 MW, in accordance with the standard in Denmark (Table 2).[16]

TABLE 2

Classification of SHP in Northern America

Country*	Small HP
Canada	up to 50 MW
Greenland	up to 10 MW
USA	up to 10 MW

Source: *WSHPDR 2016* [7]

Regional small hydropower overview and renewable energy policy

Electricity supply in Greenland is divided over many isolated systems. There is no main grid due to the large distances between various locations and many small and dispersed settlements. SHP would be an adequate technology for isolated operations in Greenland. The inland ice is the world's second largest freshwater reservoir and represents an ideal potential for hydropower development. However, to date, only about 5 per cent of Greenland's small and large hydropower potential has been developed. The small degree of utilization may be caused by the low level of electricity consumption. However, with the launching of new mining projects, a greater portion of the hydropower potential might be utilized in the future. Greenland aims to replace its diesel power plants with hydropower projects running on glacial melt water.

The installed capacity of SHP (up to 50 MW) in Canada is 3.4 GW (4.4 per cent of total installed hydro capacity and 2.6 per cent of the total generating capacity),[17,18] including 1 GW plants with up to 10 MW capacity. The economically feasible potential (including the existing SHP plants) is estimated to be about 15 GW (up to 50 MW), indicating that 23 per cent of this potential has already been developed. Only up to 15 per cent of the technically feasible SHP locations are economically feasible.

Most of the installed hydropower capacity in the USA comes from large projects built between 1930 and 1970. The total hydropower generating capacity has been relatively flat since 2000 with less than a 2 per cent total increase during that time. The installed capacity of SHP (up to 10 MW) is 3.7 GW (4.6 per cent of total installed hydro capacity and only 0.4 per cent of the total generating capacity). The economically feasible but as yet untapped SHP potential is estimated to be approximately 2.7 GW (Table 3).[9,19]

TABLE 3

SHP in Northern America

Country	Potential capacity (MW)	Installed capacity (MW)
Canada (up to 10 MW)	1,113	1,113
Canada (up to 50 MW)	(15,000)	(3,400)
Greenland (up to 10 MW)	183	9
USA (up to 10 MW)	6,366	3,676
Total (up to 10 MW)	**7,662**	**4,798**

Source: *WSHPDR 2016* [7]

The Department of Nature, Energy and Climate of Greenland supports development projects regarding RE,[21] energy efficiency and climate. Government investment has led to 50 per cent of energy supplies now being derived from RE resources.

In Canada, regulatory and policy control over the electricity industry is primarily vested in provincial governments, which own, inter alia, 87 per cent of the hydro generation assets.[22] Even though each province has its own electricity policy and regulatory agency, leading to disparate electricity tariffs between provinces relying primarily on hydropower and those relying mainly on thermal energy, Canadians enjoy the lowest overall residential energy prices out of all the countries in the Organisation for Economic Cooperation and Development.[23] The Canadian Government aims to develop a green energy sector that will help to meet emission targets, including the doubling of non-hydro renewable sources and the retirement of coal-fired power plants.[24]

In the USA, more than 3,000 private and public electric utilities operate across the country, historically within exclusive franchise service territories and subject to a high degree of governmental regulation.

The USA Department of Energy (DOE) is driving research and development efforts for SHP as part of its Water Power Program, which focuses on increasing generating capacity and efficiency at existing hydropower facilities as well as adding hydropower generating capacity to existing non-powered dams. In 2014, the DOE announced the development of a long-range National Hydropower Vision, which will establish the analytical basis for a future roadmap towards a new era of growth in hydropower, including SHP. Various state governments have developed policy and programme efforts to support SHP, including hydropower resource assessments, grant and loan funding, and efforts to improve hydropower licensing coordination between state and federal environmental agencies. Various federal and state financing mechanisms are being developed to support SHP. Many states have some form of Net Energy Metering requirement in effect, providing a strong economic incentive for distributed RE generation, including SHP.[25] The DOE also supports the National Hydropower Asset Assessment Program, an integrated water-infrastructure information platform for the management and policy planning of sustainable hydroelectricity generation.

Many states in the USA have adopted policies to encourage RE development, most prominently the adoption of a Renewables 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 RE sources, e.g. a 50 per cent target in California by 2030 and a 75 per cent target in Vermont by 2032.[26]

Barriers to SHP development

In Greenland, barriers to SHP development are experienced especially in the more scarcely populated areas. Many smaller towns and settlements are still dependent on an energy supply based on fossil fuels, since transporting electricity across long distances is associated with great costs and losses.[28] Supply and transportation is costly and associated with heavy fuel consumption. Many towns and settlements are not connected by road, so travel between them has to take place either by boat, plane or helicopter. This is especially energy intensive.[28]

In Canada, the success of hydropower development depends on transboundary cooperation between upstream and downstream jurisdictions.[29] The fragmented approach in almost all aspects of the energy sector (due to the provinces' own electricity policy and RE targets) has in some cases led to its underperformance. In recognition of Aboriginal rights, native communities (the First Nations) are now being included as hydropower project partners. From a technical perspective, unpredictable ice formations at hydropower generators can be a particular challenge, potentially causing damage to other infrastructure, such as transport passages and bridges. Overall, the situation in Canada is dynamic, but many anticipate that a hydro renaissance is possible, with hydro resources playing a larger role in the quest for a more renewable, sustainable, stable and economical power system. Other barriers in Canada include:

- SHP is normally uneconomical and requires some form of inducement (feed-in tariffs or standing offers).
- The generation of SHP is normally purchased by provincial utilities through power purchase agreements that are very competitive, resulting in a low profit margin.
- Significant environmental and regulatory requirements are still required.
- High costs of interconnection in some jurisdictions.

Despite significant recent progress in the USA, SHP developers still face barriers, including:[7]

- Lack of comprehensive information regarding suitable sites, also conduit hydropower opportunities, including canals and pipelines;
- Owners of potential conduit hydropower sites typically show risk aversion to new technology;
- Lack of standardized technology for conduit hydropower projects, with associated high custom-engineering costs;
- Notwithstanding successful recent federal reform efforts, there remain significant permitting challenges associated with SHP development;
- Uncertainty in the cost, timing and technical requirements of grid interconnection can be challenging for SHP and other distributed energy resources;
- Unfamiliarity from electrical inspectors due to the fact that few SHP projects are installed each year, making it difficult to secure electrical inspection approval;
- State and local regulatory challenges, including regulatory issues associated with water quality certifications and environmental requirements;
- Financing challenges due to high upfront costs, lengthy permitting processes for existing dam projects, variable hydrology, and other project risks.

2.4.1 Canada

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Key facts

Population	35,700,000[1]
Area	9,985,000 km[2]
Climate	The climate varies greatly throughout the country, with interior regions such as the prairies (e.g. Manitoba, Alberta) experiencing more extreme temperatures. More temperate weather is common along the west coast within the province of British Columbia. Average summer temperatures from July to August range from 20°C to 27°C, while average winter temperatures from January to February range from -30°C to 0°C.[2]
Topography	The western part of the country has a mountain range that stretches through British Columbia and Alberta and down into the USA. In the northern part of this mountain range is Mount Logan, the highest point, at 5,959 m above sea level.3 The interior provinces are dominated by the Great Plains and the Canadian Shield, which are relatively flat. Towards the Atlantic coast is the geologically older Appalachian mountain range.[4]
Rain pattern	In the coastal cities, rainfall is 1,100 mm to 1,500 mm per year. In the interior cities it is 400 mm to 500 mm and in the northern regions it is 250 mm to 300 mm. Snowfall in the east coast can reach 300 cm and in the west coast it is 50 cm.[5]
General dissipation of rivers and other water sources	Nine per cent of the total area of Canada is made up of 8,500 rivers and 2 million lakes.6 There are 12 rivers over 1,000 km long, the longest being the Mackenzie River (4,250 km), which drains into the Arctic.7 By discharge, the St Lawrence River is the largest river, with an average flow of 9,850 m^3/sec.[5]

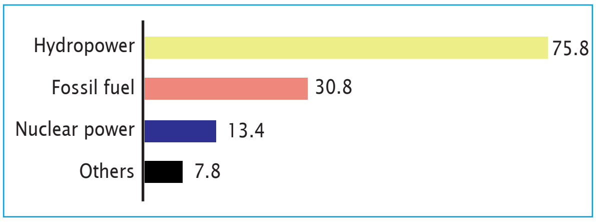
Electricity sector overview

The energy sector in Canada has an installed capacity of 127.8 GW (Figure 1), providing electricity to the entire population.[9,10] In 2015, electricity generation was 593.77 TWh and consumption was 534.31 TWh (Figure 2). The major sources of energy across Canada are hydro (59.3 per cent), fossil fuels (24.1 per cent) and nuclear (10.5 per cent) which make up the majority of the total generation. The rest comes from a combination of wind, solar and tidal.[9]

The energy mix varies substantially, with British Columbia, Manitoba, Québec, Newfoundland and Labrador's energy generated predominantly from hydroelectric sources.

FIGURE 1

Installed electricity capacity (GW)



Source: Canadian Electricity Association (2014)[9]

Alberta, Saskatchewan, Nova Scotia and New Brunswick depend heavily on fossil fuel. Ontario mostly depends on nuclear energy and hydropower. Among other renewable sources, wind accounts for 4.2 per cent of the total installed capacity, but has shown rapid growth over the past decades.[11] Table 1 shows the existing generation capacity while Figure 3 illustrates the generation mix within major Canadian provinces.

Canada has a predominately north-south transmission network that connects most strongly to the USA.[13] The transmission grid, apart from facilitating interprovincial trade, plays a key role in exporting electricity to the US market. Overall, Canada exports 7-9 per cent of its power generation and has traditionally been a net electricity exporter.[14]

In Canada, regulatory and policy control over the electricity industry are primarily vested provincially. Provincial governments have ownership over generation assets, especially hydro, nuclear, and conventional steam plants. Generation and transmission are often provided through a public entity (e.g. British Columbia, Québec, Manitoba) or produced by a competitive, bidding process (e.g. Alberta, Ontario).[14] The private sector nevertheless, in all provinces, owns an important share of the generation capacity.

TABLE 1

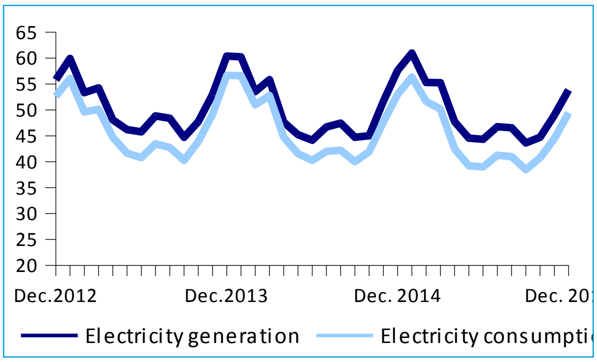
Total electricity generation by provinces in 2013 (TWh)

Sources	B.C.	Alta.	Sask.	Man.	Ont.	Que.	N.S.	N.B.	N.L.	P.E.I.
Hydro	58.2	2.2	4.5	35.4	36.7	204.9	1.1	3.3	40.75	0
Nuclear	0	0	0	0	93.1	0	0	3.9	0	0
Conventional steam	4.5	44.87	17.2	0.1	7.1	0.9	8.5	4.4	1	0
Internal combustion	0.1	0.1	~0	~0	0.8	0.3	0	0	0.1	0
Combustion turbine	1.2	13.7	0.7	~0	9.38	0.4	0.5	1.9	0.3	0
Wind	0	2.3	0.7	0.4	3.3	0.7	0.14	0.6	0.1	0.5
Solar	0	0	0	0	0.24	0	0	0	0	0
Total	64.1	63.6	23.1	35.9	149.8	206.8	10.5	13.9	42.1	0.9

Source: Key Canadian Electricity Statistics (2014)[12]

FIGURE 2

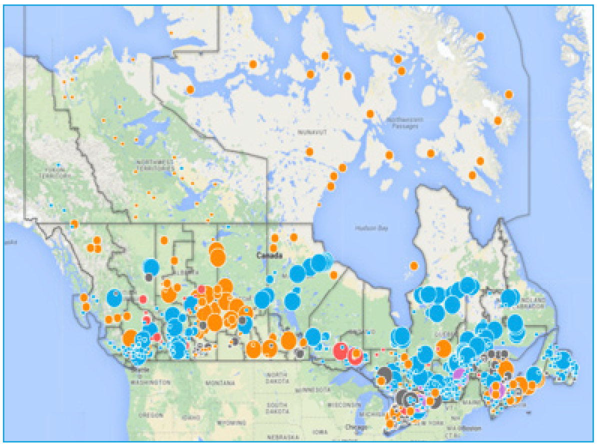
Electricity generation and consumption, 2012-2015 (TWh)



Source: Statistics Canada[33]

FIGURE 3

Electricity generation map by source in Canada



● Biomass ● Hydroelectric ● Nuclear ● Tidal
● Wind ● Solar ● Fossil fuel

Source: Canadian Electricity Association[32]

The national transmission grid is a collection of relatively loosely connected provincial grids that are linked together through varying levels of intertie capacity. British Columbia, Manitoba, Ontario and Québec have the largest external connections to the regional USA markets. The system operator coordinates power flows in real time, and the entity that acts as system operator depends on the provincial market structure. Ontario, Alberta and New Brunswick have Independent System Operators. In most other provinces, the operator also owns transmission assets.[11]

At the federal level, the stated plan has been to develop a green energy sector that, apart from having employment benefits, will help to meet the emission targets. The government has projects to double non-hydro renewable sources as well as retire coal-fired power plants.[16] With a recent change in the Federal Government in October 2015, it will be interesting to see how national goals will evolve. Ontario has already eliminated coal generation, and other provinces (Alberta and Saskatchewan in particular) face pending federal regulations. Several provinces pursue demand-side management programmes and are leaning towards smart grid investments to support the behavioural shifts. Some have taken steps in that direction by installing smart meters (e.g. Ontario).[17]

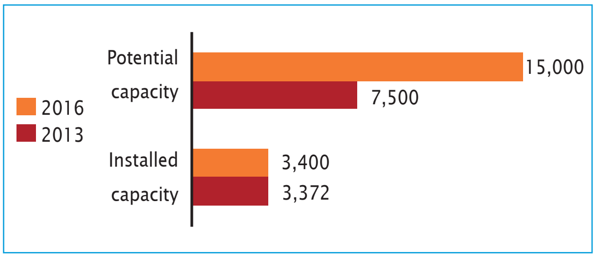
Canadians enjoy some of the lowest residential energy prices among Organization for Economic Cooperation and Development countries.[18] Each province has its own electricity policy and regulatory agency, leading to disparate electricity tariffs. Québec, BC, Manitoba, and Newfoundland and Labrador produce 56 per cent of Canadian electricity almost exclusively from hydropower plants.[19] Given the low operational cost of their generation portfolio, these provinces have the lowest electricity rates in Canada. The lack of hydropower potential for Alberta, Ontario and New Brunswick led to a reliance on thermal generation (fossil fuel and nuclear), leading to higher production costs. Provinces have separate regulation entities for reviewing and approving plans. In a majority of the provinces, utilities are operating as regulated monopolies with the exception of Ontario and Alberta, which have at least partly deregulated their electric industry over the last decade. A few key responsibilities are still handled by the Federal Government such as issuing permits for inter-provincial and international power lines, assessment for major hydroelectric developments, etc.[20] The Federal Government retains some oversight and permit responsibilities on issues relating to fisheries.

Small hydropower sector overview and potential

Natural Resources Canada (2007) defines small hydropower (SHP) as 50 MW of generating capacity.[21] However, in the absence of an international convention, a 10-15 MW limit can also be used. The installed capacity of SHP in Canada is 3,400 MW (up to 50 MW) while the potential is estimated to be 15,000 MW indicating that 23 per cent has been developed. Between the *World Small Hydropower Development Report (WSHPDR) 2013* and *WSHPDR 2016*, installed capacity for SHP up to 50 MW has increased by 1 per cent. For plants up to 10 MW, it has increased by 6 per cent, leading to a significant increase in estimated potential (Figures 4 and 5).

FIGURE 4

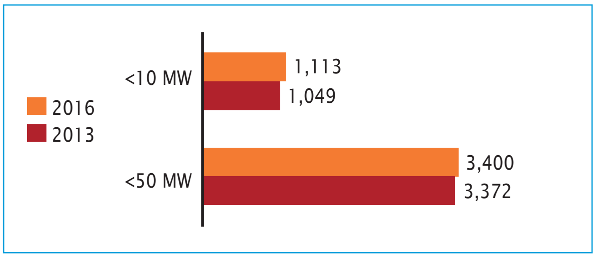
SHP capacities 2013-2016 in Canada (MW)



Sources: Statistics Canada,[34] *WSHPDR 2013*[31]
Note: Data for SHP up to 50 MW.

FIGURE 5

Installed SHP capacity



Sources: Irena,[35] Statistics Canada,[34] *WSHPDR 2013*[31]

3,400 MW of SHP capacity (up to 50 MW) accounts for 4.5 per cent of total hydro capacity in Canada.[22] As each province has a unique strategy, the plans for future development of small hydro vary across jurisdictions. In British Columbia, the Standing Offer Program targets small producers of electricity (less than 15 MW) and encourages them to sell electricity to BC Hydro, the publicly owned utility.[25] Québec, by contrast, does not have specific published plans to develop small hydro. Since the province produces more electricity than it needs, their focus is to refurbish their aging infrastructure.[26] Similarly, with most small hydro installations in Ontario dating as early as the 1990s, major investments are expected in replacing the aging assets.

Ontario's feed-in tariff (FIT) provides CA$0.246/kWh (US$0.17/kWh) for SHP development under 500 kW. This price is subjected to additional remuneration for aboriginal participation and on-peak generation.[27] Standing Offer Program in BC offers CA$0.09139/kWh (US$0.06/kWh).[25]

Renewable energy policy

Due to the provincial dominance over the electricity sector, there is a large variation in incentives provided for clean, renewable development across different provinces. The schemes are also subjected to frequent amendments and adjustments. A brief description of some of these renewable policy measures are discussed below:

- Clean energy fund
  An Economic Action Plan that includes the Clean Energy Fund, a five-year, CA$795 million (US$558.6 million) programme to support clean energy technology research.[28]
- Standard offer programmes
  The qualifying projects are subjected to a capacity restriction and required to connect to the distribution. The programme usually guarantees a sustained tariff for a period of 20 years.
- FIT programmes
  The programme assures priority grid connection and long-term stable prices (40 years for hydropower and 20 years for others) for electricity generated from renewable resources, subjected to capacity restrictions. At present, FIT programmes are available only in Ontario. Within the first two years, it has extended Ontario's renewable capacity by 4,600 MW.[29]
- Net metering
  Net metering allows generators to send the excess electricity, after their own use, to the grid. The credit received in return can be applied against future electricity use or at times, can be subjected to annual monetary returns. Net metering programmes are available in almost every province across Canada.
- Requests for proposal
  A request for proposal (RFP) usually involves a specific target announced by the government that needs to be executed by the monopoly utility in particular jurisdiction. The proponents bid according to a fixed delivery schedule and are eligible to get a defined tariff rates which may or may not be subjected to escalation.

Barriers to small hydropower development

Overall, the situation in Canada, as in most jurisdictions, is dynamic and hard to forecast in detail. Many anticipate that a hydro renaissance is possible with hydro resources playing a larger role in the quest for a more renewable, sustainable, stable and economical power system. Some main barriers include:

- The fragmented approach in almost all aspects of the energy sector due to the provinces' own electricity policies and RE targets, has in some cases led to its underperformance. Transboundary cooperation, between upstream and downstream jurisdictions, can be challenging.[30]

- Another common consideration for hydropower development throughout Canada is Aboriginal rights. Native communities throughout the country are diverse, and often their livelihood depends on water courses, therefore consultation of these stakeholders is important.[30] A crucial step in this regard has been including the Aboriginals as hydropower project partners.
- From a more technical perspective, however, ice formation can be a particular challenge. The installation of hydropower generators can cause unpredictable ice formations that cause damage to other infrastructure, such as transport passages and bridges.[30]

2.4.2 Greenland

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Key facts

Population	57,728 [1]
Area	2,166,086 km^2
Climate	The climate is arctic to sub-arctic with cool winters and cold summers.[1] Monthly mean temperatures in the capital, Nuuk, vary between -8°C and 7°C. In Upernavik in the north the variation is between -20°C and 6°C.
Topography	Flat to gradually sloping icecap covers all but a narrow, mountainous, barren, rocky coast.[1] The ice cap is up to 3,200 m thick.
Rain pattern	The average annual precipitation is 756 mm. On average, there are 94 days per year with more than 0.1 mm precipitation. Most of the annual precipitation falls in September, with an average of 89 mm. The driest weather is in March, with an average of 39 mm.[2]
General dissipation of rivers and other water sources	The Greenland ice cap has an estimated volume of 1.7 million km^3. The Ilulissat Glacier is one of the fastest and most active glaciers in the world. It produces 10 per cent of all Greenland's ice fields, corresponding to around 35 billion tons of ice a year.[17] Across a 2,000-square-mile area of ice, over 500 active rivers and streams drain in moulins, moving the melt water into the ocean through and under the ice sheet. At the base of the ice sheet the drainage occurs at a rate between 55,000 and 61,000 cubic feet per second.[18]

Electricity sector overview

In 2014, 59 per cent Greenland's electricity and heat came from hydropower. In 2013, this number was 62 per cent and in 2010 it was 60 per cent, despite the commissioning of the hydropower plant in Paakitsoq at Ilulissat in September 2013. Diesel generation accounted for the remaining balance. In 2014, the total generation of electricity and heat was 541 GWh (Figure 1).[3] Nukissiorfiit, the energy company of Greenland, is the sole supplier of electricity on the market in Greenland. They generate and transmit electricity to 17 towns and 53 settlements.[4] Nukissiorfiit is owned by the Government of Greenland, Naalakkersuisut. The electrification rate in Greenland is 100 per cent.[20]

FIGURE 1

Electricity and heat generation in Greenland (GWh)

Source: Nukissiorfiit[3]

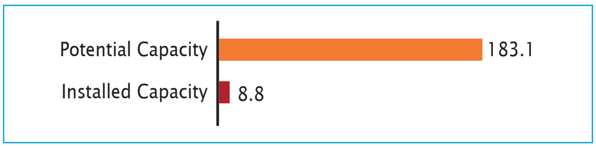
Greenland is the world's largest island and is not connected to other areas. Supply in Greenland is divided on many isolated systems. For general consumption, the average electricity tariff for light and power was US$0.47/kWh in 2015.[5]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Greenland is up to 10 MW.[4] The installed capacity of SHP is 8.8 MW while the potential is estimated to be 183.1 MW, indicating that only 4.8 per cent has been developed (Figure 2).[8]

FIGURE 2

SHP capacities in Greenland (MW)



Source: Nukissiorfiit [8,9]

In 1951, the Swiss geologist H. Stauber pointed out the possibility of using the great amounts of melting water from the inland ice for hydropower in Greenland. In the beginning of the 1970s, the planning of hydropower development increased in pace. Through studies of maps and climate, potential hydropower areas were localized in Western Greenland. The first hydropower plant was commissioned in 1993 in Nuuk, Buksefjorden after which a hiatus in the establishment of new hydropower plants occurred.[6]

In 2005, two new SHP plants were commissioned in Tasilaq and Qorlortorsuaq. In 2010, a new hydropower plant was commissioned in Sisimiut and in 2012 another was commissioned in Ilulissat.[9]

The inland ice is the world's second largest freshwater reservoir (Antarctica being the largest) and represents, with precipitation, an ideal potential for hydropower. The theoretical potential for hydropower in Greenland is large enough to supply much of Europe with electricity. However, at present, most of the localized potential remains economically sustainable.[7] However, Greenland is aiming to replace its diesel power plants with hydropower projects running on glacial meltwater. The latest project is the 22.5 MW station for the town of Ilussat. The unstaffed project will be built 200 m below the ground and operated remotely. This project is the third of its kind in Greenland after the 9 MW Qorlortorsuaq project in 2007 and the 15 MW Sisimut project in 2010.[19]

In 2015, Greenland had two SHP plants with a total installed capacity of 8.8 MW (29 GWh/year) and three large hydropower plants with a total installed capacity of 82.5 MW (288 GWh/year). The total installed capacity is 91.3 MW of which SHP provides about 10 per cent.[8] In 2005, according to Nukissiorfiit, Greenland had a localized potential of 51 SHP facilities with a total potential of 183 MW (948 GWh/year) and 26 large hydropower facilities with a total potential of 1,724 MW (13,533 GWh/year). Thus the total potential is 1,907 MW.[8] Note that this is the total potential and that it doesn't consider any practical or economic constraints. In 2013, electricity production from hydropower satisfied most of the electricity consumption except for the demand in isolated settlements.[3]

The hydropower potential in Greenland is much greater than the installed hydropower capacity. The small degree of utilization might be explained by a lack of electricity consumption. With the launching of new mining projects and an increase in energy consumption, a greater portion of the hydropower potential might be utilized in the future. However, the pace of implementation of these new projects is uncertain. Tim Boersma et. al. (2014) concluded in a report on the promise and pitfalls of energy and mineral resources in Greenland that "there is wide agreement that Greenland possesses a vast treasure trove of mineral and energy resources, but there is significantly less agreement about whether and when some of these projects will make it to the market. In the next five years, it seems that a small number of mining projects may reach production, but overall the aggressive pace of development that the Greenland administration has laid out since the most recent elections in the spring of 2013 seems too optimistic. More importantly, the larger part of Greenland remains unexplored to date, and thus more data would be useful."[10]

Renewable energy policy

Naalakkersuisut has consciously made an effort to educate the populace on the importance of reducing the country's CO_2 emissions. A climate campaign aimed at the population at large was aired in the spring of 2013. The campaign promoted climate friendly behaviour and encouraged citizens to reduce their consumption of fossil fuels where possible.[11] The Department of Nature, Energy and Climate, which is part of the ministries of the Greenlandic Government, provides annual support of about US$200,000 to development projects regarding renewable energy (RE), energy efficiency, and climate.[12] The Government of Greenland has in many years invested about 1 per cent of the country's GDP, which has led to more than 50 per cent of the energy supply coming from RE sources.

Hydropower is by far the most important RE source in Greenland, but several small scale initiatives are also worth noting. The Arctic Technology Centre (ARTEK) in Sisimuit, affiliated with the Technical University of Denmark, has launched numerous research and development projects regarding examinations of solar power potential, wind power potential, and sustainable building. The Greenlandic Government has also examined the possibilities of introducing electric cars in Nuuk. With access to surplus energy from the hydropower plant and a limited system of roads the challenges that often characterizes electric vehicle deployment are easily overcome.[13]

In 2012, Naalakkersuisut requested Denmark to take territorial reservation for Greenland regarding the ratification of the second commitment period of the Kyoto Protocol. The second commitment period extends from 2013-2020. A territorial reservation means that Greenland will be exempt from international reduction commitments of greenhouse gas emissions. Throughout the first commitment period (2008-2012), however, Greenland was included in Denmark's reduction commitments. In this period Denmark committed to a 21 per cent reduction within which Greenland committed to 8 per cent.[14]

Barriers to small hydropower development

Barriers to SHP development are experienced especially in the more scarcely populated areas. Many smaller towns and settlements are still dependent on an energy supply based on fossil fuels, since transporting electricity across longer distances is associated with greater costs and losses.[15] The coastline of Greenland is longer than the Earth's circumference.[1] Towns and settlements are scattered along the coast often with great distances between them. Supply and transportation are costly and associated with heavy fuel consumption. The challenging terrain prevents some towns and settlements from being connected by road and travel between them has to take place either by boat, plane or helicopter. In the winter, when sea ice coverage can make it difficult to move by water, most transport is by air. This is especially energy intensive.[16]

2.4.3 United States of America

Kurt Martin Johnson, Telluride Energy[1]

Key facts

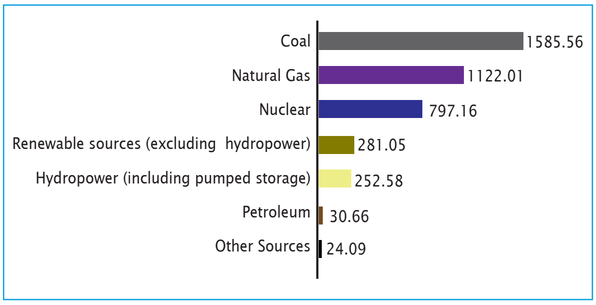
Population	320,000,000 [2]
Area	9,826,675 km^2
Climate	The climate of the USA varies widely according to location, from arctic in Alaska, tropical in Hawaii, Mediterranean in California, arid in the Southwest and temperate across much of the country.
Topography	There is a large central plain with hills and low mountains in the east and mountains in the west. The highest point is Mount Denali in Alaska, at 6,194 m above sea level. The lowest point is Death Valley, California, at 86 m below sea level.
Rain pattern	Rainfall varies according to location. Statewide averages of annual rainfall range between 1,618 mm in Hawaii and 241 mm in Nevada. For the entire USA, excluding Hawaii and Alaska, the average amount of rainfall is 767 mm.[3]
General dissipation of rivers and other water resources	The nation's largest river systems based on flow volume are the Columbia River in the north-west and the Mississippi River in the south-east.

Electricity sector overview

In 2014, total electricity generating capacity in the USA was 1,003.3 GW.[4] Total hydropower generating capacity has been relatively flat since 2000, with less than a 2 per cent total increase during that time.[5]

FIGURE 1

Annual electricity generation by source in the USA



Source: EIA[6]

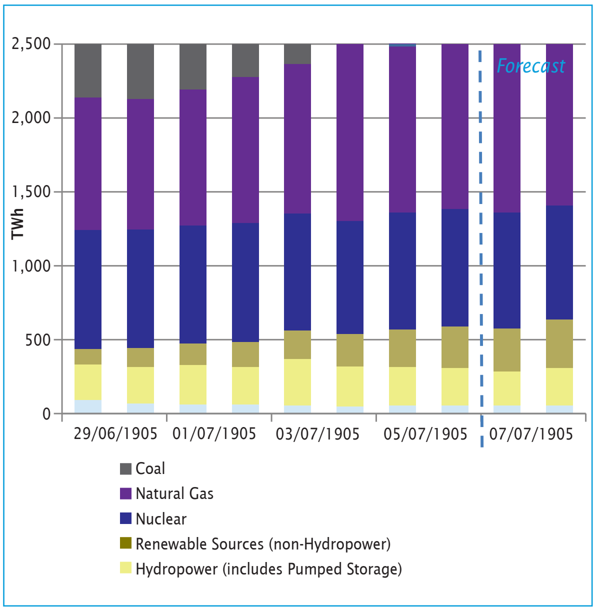
In 2014, annual generation was approximately 4,100 TWh. Coal powered plants provided approximately 38.7 per cent, natural gas provided 27.4 per cent, nuclear provided 19.4 per cent, renewable sources (excluding hydropower) 6.9 per cent and hydropower (including pumped storage) provided 6.2 per cent. Other sources, including petroleum contributed approximately 1.3 per cent (Figure 1).[5,6]

For many years, coal has been the largest single source of electricity supply, although recently natural gas generation has been growing rapidly, along with wind and solar.[5] Hydropower, as a percentage of total electricity generation, has been relatively stable since 2007 (Figure 2).[7] In general, electricity load growth has been minimal, notwithstanding economic growth, as the economy becomes more energy efficient.

In 2014, the country's total electricity consumption was 3,681 TWh. Commercial sales of electricity comprised approximately 36 per cent to the residential sector, 25 per cent to the commercial sector and 25 per cent to the

FIGURE 2

Annual electricity generation in the USA by source, 2007-2014 (TWh)



Source: EIA[6]

industrial sector. Direct use of electricity by commercial and industrial facilities accounted for 4 per cent (Figure 3).[6] The USA has a 100 per cent electrification rate.

Historically, the USA's electricity industry has been a mix of private and public utilities that generate and deliver electricity to customers within exclusive franchise service territories. Currently, more than 3,000 electric utilities operate across the country.

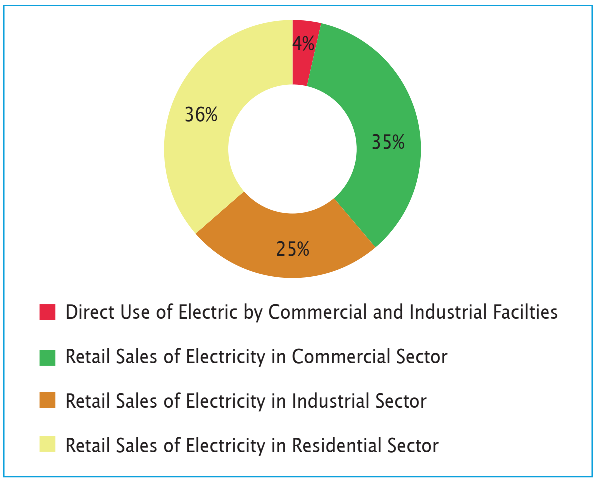
More recently, some states and regions have established competitive markets for both electricity generation and delivery. This process is often referred to as electric industry restructuring or deregulation and has resulted in new entrants to all segments of the electricity industry, including generation, transmission, and delivery.

Because of the historically exclusive nature of utility service territories, the electric industry has been subject to a high degree of governmental regulation. 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.

In addition, the Federal Energy Regulatory Commission (FERC), an independent agency of the US Government, regulates the interstate transmission of electricity. A key outcome of electric industry restructuring has been the formation of Independent System Operators (ISOs) that 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

FIGURE 3

Annual electricity consumption in USA by source, 2007-2014 (%)



Source: EIA[6]

time and operate ancillary service markets. The seven USA-based ISOs are regulated by the FERC.

The move toward greater competition in electricity supply and delivery has fostered a shift in electricity generation sources. Environmental concerns, particularly related to airborne emissions from fossil fuel-based electricity generation sources, are also affecting utility generation choices, typically in response to regulatory requirements.

Electricity tariffs are a product of a utility's generation, transmission, distribution and administrative costs, as well as return on investment in the case of investor-owned utilities. Recent electricity rates have been relatively stable with low annual growth, partly in response to low wholesale prices resulting from an abundance of natural gas. In December 2014, the average electricity prices were as follows: residential: US$0.12/kWh, commercial: US$0.10/kWh and industrial: US$0.07/kWh. Residential rates are expected to reach US$0.13/kWh by 2016.[7,8]

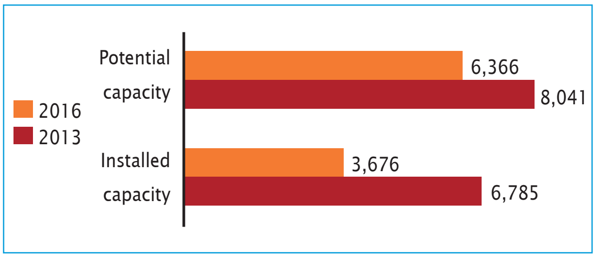
Small hydropower overview and potential

There is no widely agreed-upon definition of small hydropower (SHP) in the USA. However, for this report, SHP is defined as hydropower plants with an installed capacity of up to 10 MW. This is the largest capacity that can qualify for a SHP exemption at the FERC pursuant to the Hydropower Regulatory Efficiency Act of 2013.

The total SHP capacity is 3,676 MW with an estimated potential for at least an additional 2,690 MW indicating that approximately 58 per cent of the total potential has been developed.[10,12] In comparison to data from the *World Small Hydropower Development Report (WSHPDR) 2013*, both installed capacity and potential have decreased. This is due to different methods of analysis (Figure 4).[9]

FIGURE 4

SHP capacities 2013-2016 in the USA (MW)

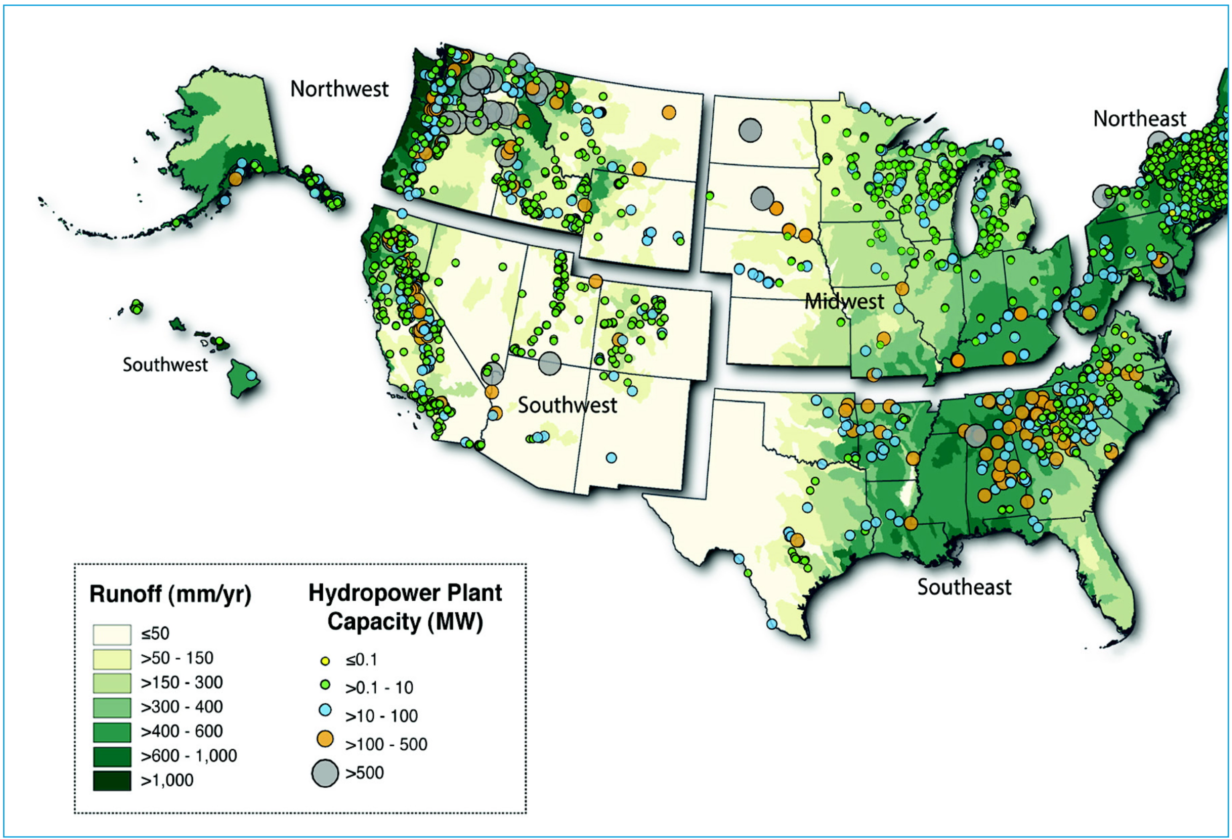


Source: Various[9,10,12]

Total hydropower generating capacity, not including pumped storage, is approximately 80,000 MW from 2,198 hydropower plants.[7] Approximately half of this capacity is located in three states: Washington, Oregon and California (Figure 5).[7] Approximately half of the capacity is owned by three federal agencies: the United States Army Corps of Engineers, the Bureau of Reclamation and the Tennessee Valley Authority. The 176 plants they own account for 49 per cent of the capacity but only 8 per cent of the plants.[7]

FIGURE 5

Map of hydropower plants in the USA



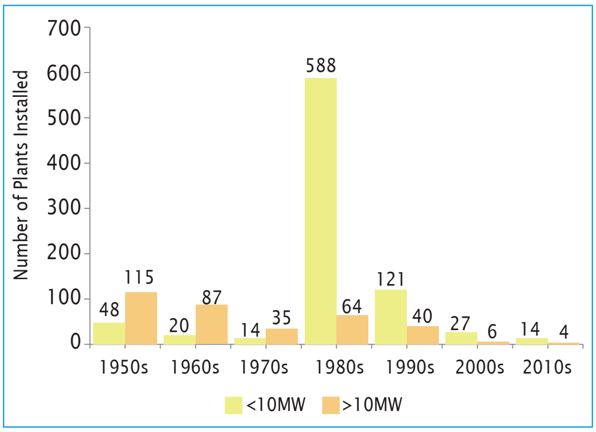
Sources: Uria-Martinez et al.,[7]

SHP comprises approximately 75 per cent of the current hydropower fleet in terms of number of plants. The existing fleet of SHP plants consists of 1,640 plants with a combined generating capacity of approximately 3,670 MW.[10] In terms of numbers of units, most planned new hydropower development is for small projects (less than 10 MW) typically built using existing infrastructure, including existing dams, canals, and pipelines.

Most of the installed hydropower capacity in the USA comes from large projects built between 1930 and 1970.

FIGURE 6

Number of hydropower plants installed by size in the USA since 1950



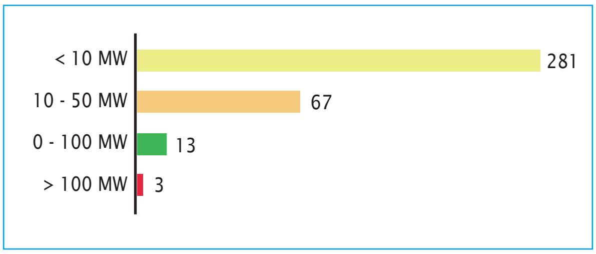
Source: National Hydropower Asset Assessment Program[11]

Since the 1980s, most new hydropower capacity additions have been small, including plants built in response to the Public Utility Regulatory Policies Act (PURPA), signed into law in 1978, which opened the door to development of smaller plants (Figure 6).

As of December 2014, there were 281 SHP projects of less than 10 MW within the FERC development pipeline (Figure 7). The majority of these projects are at their early stages, in which project developers obtain a permit from the FERC to complete feasibility studies. These preliminary permits confer upon the developer the exclusive right to apply for a license at a particular site within a three-year period. If that right is not exercised and an extension is not granted, the permit expires and the site can be pursued by other developers. The attrition

FIGURE 7

Hydropower projects in the FERC and Bureau of Reclamation development pipeline by capacity



Source: Uria-Martinez et al.[7]

rate between the preliminary permit phase and the next step of the development process is typically high.

Currently, only about 3 per cent of the nation's roughly 80,000 existing dams include hydropower. The two single largest US hydropower owners—the United States Army Corps of Engineers and the Bureau of Reclamation— are also the owners of a significant portion of the non-powered dams with hydropower development potential.[11] Recently completed federal and state resource assessments have highlighted the magnitude of the untapped SHP development opportunity. ORNL issued an assessment in 2012 of the nation's non-powered dams (NPD) and estimated that 12,000 MW of untapped hydropower capacity was available on existing non-powered dams (Figure 8).[10] Most of the untapped sites are for SHP, with a potential for approximately 2,556 MW of new capacity distributed across existing dams at 54,191 prospective project sites.[10]

There has not yet been a comprehensive national assessment of untapped SHP generating potential that would use existing conduits (including irrigational canals, water supply pipelines, and opportunities available at water treatment plants), although some state and federal agencies have started to compile relevant data.

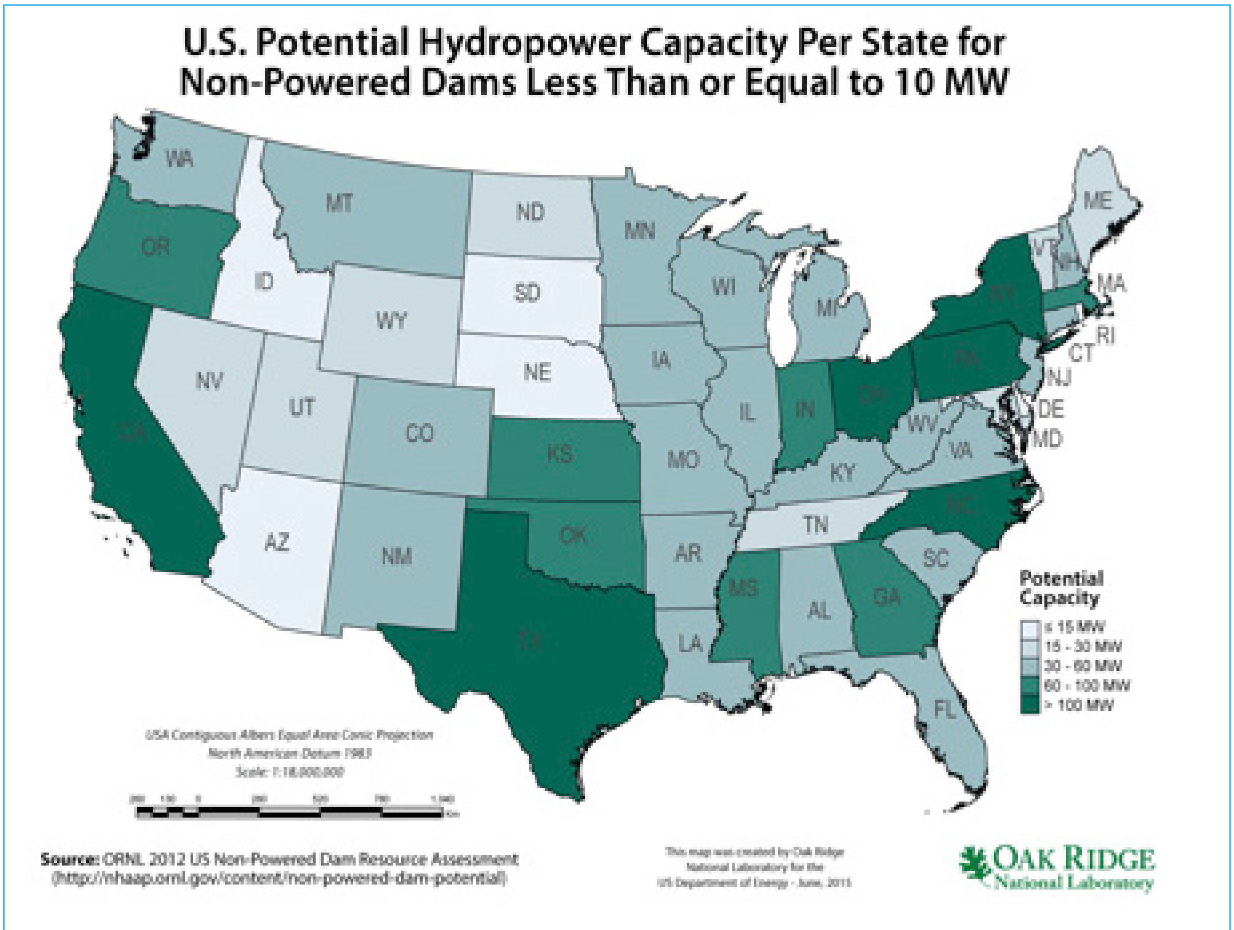
A 2012 study by the United States Bureau of Reclamation examined energy development potential on Reclamation-owned facilities. Reclamation found that 191 canals had at least some level of hydropower potential, and 70 of those sites could be considered economically viable for development. This report concluded that there are 104 MW of potential capacity and 365 GWh of potential generation at the 373 Bureau of Reclamation canals studied.[12]

A 2013 study performed by the Colorado Department of Agriculture analysed the hydropower potential of pressurized irrigation systems. The study estimated that 7 per cent or 175,000 acres of Colorado's irrigated farmland is suitable for new, pressurized irrigation and installation of SHP plants. Researchers determined that as much as 30 MW of power could be generated from these systems.[13] On the basis of those findings, the Colorado Department of Agriculture created a programme to support development of agricultural hydropower.

The Department of Energy (DOE) is driving research and development efforts for SHP as part of its Water Power Program, which includes support for conventional hydropower, including SHP, as well as marine and hydrokinetic technologies. In 2014, the DOE announced

FIGURE 8

Locations of untapped SHP potential on existing non-powered dams in the USA



Source: B. Hadjerioua et al.[10]

the development of a long-range national Hydropower Vision, which will establish the analytical basis for a future roadmap towards a new era of growth in hydropower, including SHP.

Various state governments have developed policy and programme efforts to support SHP, including Oregon, California, Massachusetts, Rhode Island, Vermont, Colorado, Pennsylvania, Maine, and Wyoming. Typical state initiatives include hydropower resource assessments, grant and loan funding, as well as efforts to improve hydropower-licensing coordination between state and federal environmental agencies. For example, in 2013, a Memorandum of Understanding (MOU) was signed between the FERC and the California State Water Resources Control Board to coordinate pre-application activities for non-federal hydropower proposals in California. The purpose of the MOU was to coordinate procedures and schedules prior to the FERC's review of hydropower license applications and the State Water Board's review of water quality certification applications. This collaboration is expected to reduce redundancy and streamline the issuance of environmental documents that satisfy the legal requirements of both federal and California environmental laws.

In 2014, Congress provided the first-ever funding allocation for the Section 242 Program, a hydropower incentive programme that was created in the Energy Policy Act of 2005. The programme received US$3.6 million in appropriations for 2014 and US$3.9 million for 2015. The programme's incentive for new hydropower generation at existing facilities is currently equal to about US$0.15/kWh, with maximum payments of US$750,000 per year for up to 10 years, subject to availability through ongoing congressional appropriations. The programme's congressional authorization is due to expire in 2015, although bipartisan legislation to reauthorize the programme has been introduced in both the House of Representatives and the Senate.

In addition, various federal and state financing mechanisms are being created to support SHP. For example, the Department of Agriculture's Rural Energy for America Program (REAP) has started providing support for SHP, including renewable energy (RE) project grants that support up to 25 per cent of project costs with a maximum of US$500,000. Eligible REAP grant applicants are typically small rural businesses.

Various states have developed financing programmes specific to SHP. The Colorado Water Conservation Board modified its existing water-infrastructure financing programme to create a hydropower loan programme that can finance the construction of hydropower projects with loan terms of 30 years at an interest rate of 2 per cent. For example, the 8 MW hydropower project at Ridgway Reservoir in Western Colorado, completed in June 2014, was made possible by a US$15 million loan through the Colorado loan programme.

SHP systems installed adjacent to a local electricity load can typically take advantage of net energy metering (NEM). Under a NEM agreement, generated electricity is used directly by an adjacent facility. Any excess generation can be exported to the utility grid for use at a later time with the generator receiving a one-for-one credit at full retail value for any electricity generated on-site. Many states have some form of NEM requirement in effect, providing a strong economic incentive for distributed RE generation, including SHP.[14]

Renewable energy policy

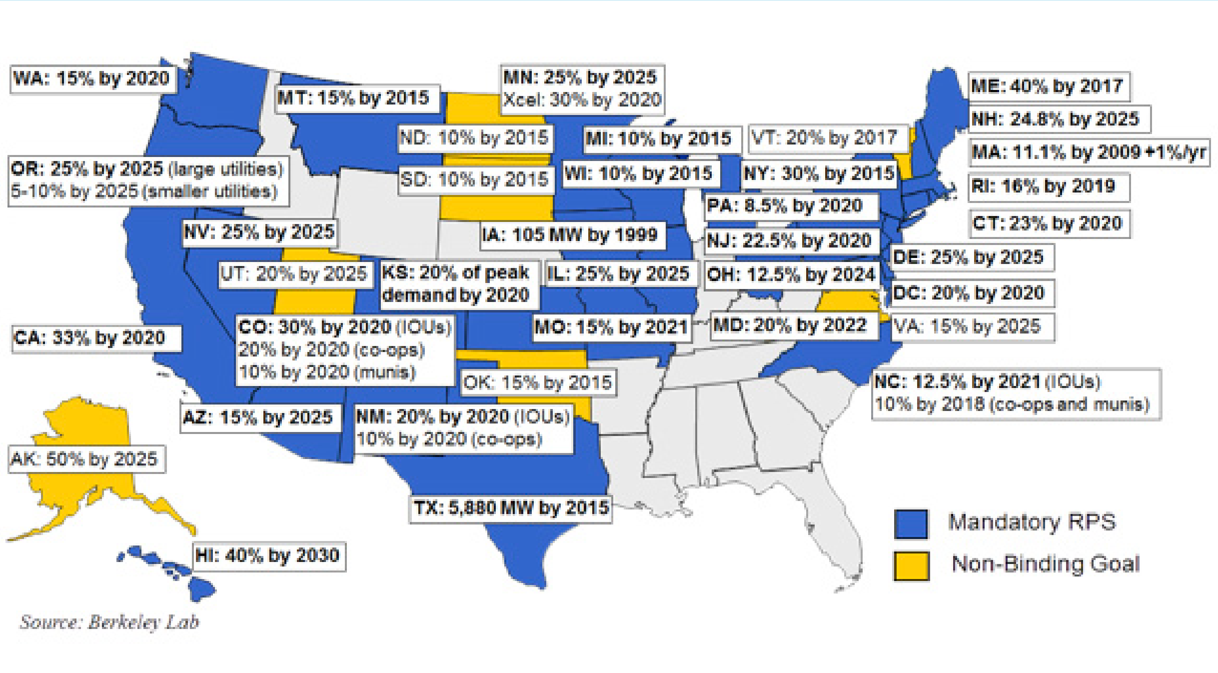
PURPA, signed into law in 1978, introduced competition into the USA's electric power industry, particularly in the generation sector. PURPA conferred special rate and regulatory treatment on a new class of generators known as qualifying facilities, or QFs. These were made up of cogeneration facilities and small power production facilities of 80 MW or less that use a RE source (hydro, wind, solar, biomass, waste, or geothermal).[15] PURPA required electric utilities to interconnect with and purchase power from QFs at the cost that the utility would otherwise incur in generating the power themselves or procuring power from other sources.

In the Energy Policy Act of 2005, Congress made an important modification to PURPA, providing relief from PURPA's mandatory purchase obligation to utilities if the FERC determines that QFs have non-discriminatory access to the market. In this context, the 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. However, the FERC established a rebuttable presumption that QFs with a net capacity of 20 MW or less (small QFs) do not have non-discriminatory access to wholesale markets. Thus, the utility PURPA purchase obligation remains in force for small QFs. This makes it possible for SHP generators to secure a utility power purchase agreement.[16]

The Federal Government has previously enacted tax incentives to spur RE development including the production tax credit (PTC) and investment tax credit. Both, however, are currently expired for hydropower and other technologies. SHP has also been eligible for federal accelerated depreciation tax treatment and some states offer tax incentives and exemptions. Hydropower, however, has historically received unequal treatment in federal tax incentives—for example, it receives half the value that wind does under the PTC. Individual states have adopted policies to encourage RE development. The most prominent of these policies has been the adoption of a renewables 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 RE sources. Generally, the RE is procured as wholesale purchases through competitive market solicitations.

FIGURE 9

Status of RPS policies in the USA, December 2014



Source: Lawrence Berkeley National Laboratory[18]

As of the end of 2014, 29 states and the District of Columbia had instituted RPS policies, covering 56 per cent of total retail electricity sales in the USA.[17] In 2015, California Governor Jerry Brown announced a goal to raise the state's RPS target from 33 per cent in 2020 to 50 per cent in 2030. Vermont Governor Peter Shumlin signed into law a bill that requires the state's utilities to source 55 per cent of their sales from renewable sources in 2017. This number was set to rise to 75 per cent by 2032. Hawaii Governor David Ige has also signed legislation making Hawaii the first state to adopt a 100 per cent RPS, aiming to reach that goal by 2045 (Figure 9).

Some states have adopted feed-in tariff (FIT) programmes. For example, California has adopted a RE FIT for renewable generators up to 3 MW, and Vermont offers an FIT for eligible resources less than 2.2 MW in size.[19]

In addition, state government policies promoting retail electricity competition have resulted in new RE development. The opportunity for electricity consumers to choose the source of their power has led many customers to purchase power directly from RE providers, beginning in the late 1990s with electricity choice in restructured electricity markets. Increasingly, customers are seeking to obtain their electricity supplies from sources with minimal environmental impacts. Large companies as well as government entities are seeking out direct investments or purchases of RE as an element of their environmental sustainability commitments.[20] Taken together, state RPS policies and the voluntary purchase market have been responsible for the bulk of new RE development over the past decade.[21]

Federal policies to address climate change are likely to drive additional RE deployment in the future. In June 2014, the US Environmental Protection Agency (EPA) issued a proposal to regulate CO_2 emissions from existing power plants under Section 111(d) of the Clean Air Act.[22] If implemented, the EPA's Clean Power Plan would cut carbon pollution from the power sector by 30 per cent from 2005 levels by 2030. The United States Energy Information Administration (EIA) has estimated that RE would play a critical role in achieving these reductions under a range of different market conditions and policy assumptions. According to the EIA, the rule could spur the deployment of as much as 174 GW of additional RE generating capacity by 2040.[23]

Legislation on small hydropower

Federal permitting requirements for SHP have recently been significantly simplified. In August 2013, President Obama signed into law two pieces of legislation aimed at making the regulatory process more efficient for SHP: H.R. 267, the Hydropower Regulatory Efficiency Act, and H.R. 678, the Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act.

The Hydropower Regulatory Efficiency Act created a regulatory off-ramp from the FERC permitting requirements for non-controversial hydropower projects on existing conduits that are less than 5 MW, provided that there are no public objections to the project during a 45-day public notice period administered by the FERC. The bill also increased the FERC conduit exemption from licensing to 40 MW,[i] directed the FERC to explore a two year licensing process for hydropower development at existing non-powered dams and closed-loop pumped storage projects, increased the FERC SHP exemption from licensing from 5-10 MW, authorized the FERC to grant developers two year preliminary permit extensions and directed DOE to prepare reports regarding pumped storage and conduit project opportunities.

The Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act authorized small conduit power projects (under 5 MW) on infrastructure owned by the Bureau of Reclamation and provided irrigation districts and water user associations the first right to develop hydropower projects. The Act also directed the Bureau to use its National Environmental Policy Act categorical exclusion process for small conduit applications.

In June 2014, the Water Resource Reform and Development Act was signed into law. It states that it is the policy of the US that the development of non-federal hydroelectric power at United States Army Corps of Engineers civil works projects, including locks and dams, shall be given priority, and that Corps approval shall be completed in a timely and consistent manner. As noted above, a majority of the nation's non-powered dam hydropower potential is located on Army Corps dams.

Projects that are not eligible for off-ramp in accordance with the Hydropower Regulatory Efficiency Act of 2013, or for one of the two types of FERC exemptions (conduit exemption or under 10 MW SHP exemption) must apply to the FERC for a hydropower license. There is an exception to this for projects constructed on Bureau of Reclamation facilities. These are subject to the Bureau's hydropower permitting process, which is called a Lease of Power Privilege.

The FERC licensing process can be lengthy and time consuming, although the FERC is currently investigating the potential for development of a two year licensing process in response to a directive from the Hydropower Regulatory Efficiency Act of 2013. In addition, the United States Congress is currently developing comprehensive energy legislation that may include additional permitting reforms for hydropower.

SHP projects are typically RPS eligible, while large hydropower projects are often excluded from RPS eligibility. Common hydropower restrictions for RPS eligibility include restrictions based upon capacity, type, and environmental sustainability criteria. One environmental standard is the Low Impact Hydropower Institute's certification standard which is used for RPS eligibility in a variety of states.[24] Many RPS policies also have outdated requirements for new development which can disqualify hydropower production from RPS eligibility.

Barriers to small hydropower

Despite significant changes in recent years, developers of SHP still face barriers, including:

- Lack of comprehensive information regarding appropriate sites. Although federal agencies have recently completed nationwide hydropower resource assessments for existing non-powered dams, there has not yet been a comprehensive assessment regarding conduit opportunities (including canals and pipelines).
- Risk aversion to new technology. Owners of potential conduit hydropower sites, usually water agencies, are typically cautious and risk averse with respect to the water systems for which they are responsible. There are relatively few existing conduit hydropower installations in the USA and many water agencies have no understanding of available SHP technologies. Many newer, more innovative and cost-competitive SHP technologies that offer a potential solution to high project costs do not necessarily have long operational track records.
- Lack of standardized technology. There are few standard designs due to relatively few conduit hydropower projects being developed.
- Lengthy permitting. Notwithstanding successful recent federal reform efforts related to small conduit hydropower, there remain significant permitting challenges associated with SHP development on existing non-powered dams.
- Electrical interconnection. Uncertainty in the cost, timing and technical requirements of grid interconnection can be challenging for SHP and other distributed energy resources. Interconnection processes can be expensive and time-consuming with timetables that are not always consistent with the needs of SHP developers.
- Electrical inspection. Due to the fact that very few SHP projects are installed each year, most electrical inspectors are not familiar with them, making it difficult to secure electrical inspection approval for very small plants that are net-metered. SHP is not currently addressed in the existing National Electrical Code. The USA's SHP industry is not yet large enough to support mass manufacturing of standardized products that have completed independent certification. Costs associated with post-manufacture, in-the-field product testing and approval to ensure product safety can adversely affect project economic feasibility.
- State and local policy issues. State and local regulatory challenges can be a barrier to SHP development, including regulatory issues associated with water quality certifications as well as other state and local environmental requirements.
- Financing, SHP projects can experience financing challenges due to high upfront costs, lengthy permitting processes for existing dam projects, variable hydrology and other project risks.

Note: i. Obtaining a FERC exemption is typically a simpler and less lengthy process than obtaining a FERC license.

CHAPTER 3
Asia

International delegates visiting a small hydropower turbines manufacturer in Zhejiang, China
Photo from Zhejiang Jinlun Electromechanic

3.1 Central Asia

Edilbek Bogombaev, Foundation Green Energy

Introduction to the region

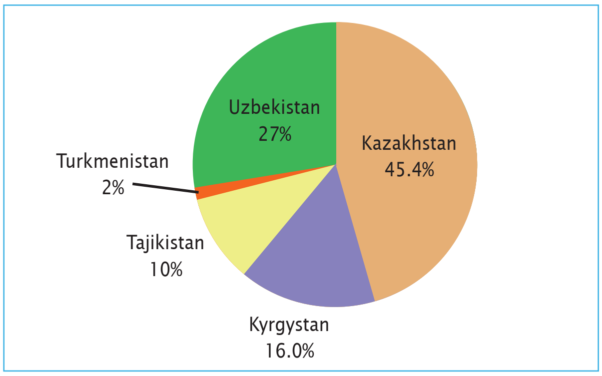
Central Asia covers inland Asia and is bordered by China in the east, the Caspian Sea in the west, Iran and Afghanistan in the south and the Russian Federation in the north. The region includes five countries: Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan. The topography and climate of the region vary from arid desert (Kazakhstan, Turkmenistan and Uzbekistan), to mountain ranges and grasslands (Kyrgyzstan and Tajikistan). Rainfall can be intermittent, with lows of 100-200 mm in Uzbekistan and higher averages of 2,000 mm in central Tajikistan.

The most important rivers of Central Asia are the Amu Darya and the Syr Darya. Passing through all five countries, the Amu Darya represents an important source of hydropower in the region. Kazakhstan has one of the lowest water availability rates in Eurasia (20 m^3/km^2) despite having a high number of small and large rivers as well as lakes. The water resources on the territory of Kyrgyzstan are not allocated uniformly and are mainly concentrated in the unpopulated and economically underdeveloped areas. Landlocked Tajikistan, on the other hand, has abundant water resources with 8,476 km^2 of glaciers, 947 rivers stretching over 28,500 km and 1,300 freshwater lakes. In Turkmenistan, the main rivers are located in the far south and east; the most important of which is the Amu Darya. Most of Uzbekistan lies between the Amu Darya and the Syr Darya. However, due to a large extension of the irrigation area, the country often experiences water scarcity.[5,6,7,8,20] An overview of the countries in Central Asia is presented in Table 1.

Uzbekistan and Kazakhstan together account for about 72 per cent of the regional share of installed small hydropower (SHP) (Figure 1). Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, the installed SHP capacity has increased by 42.7 per cent from 183.5 MW to 261.8 MW, largely due to the development in Uzbekistan and Tajikistan (Figure 2).

FIGURE 1

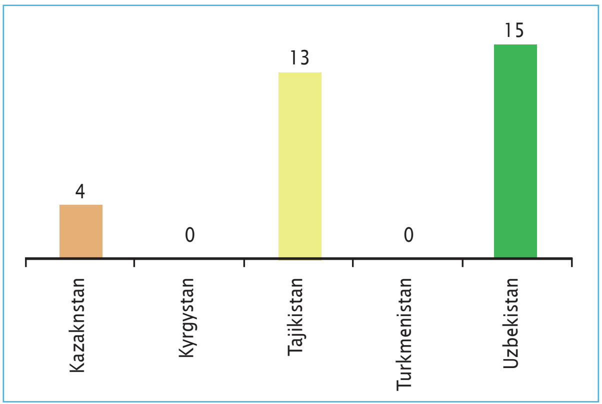
Share of regional installed capacity of SHP by country



Source: *WSHPDR 2016*[17]

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for Central Asia



Sources: *WSHPDR 2013*,[18] *WSHPDR 2016*[17]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

TABLE 1

Overview of countries in Central Asia (+/- % change from 2013)

Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Kazakhstan	17.67 (+0.7%)	46.8 (+5.8pp)	100 (+2pp)	21,310 (+14%)	97,900 (+25.4%)	2,675 (+18.4%)	8,800 (+10.1%)
Kyrgyzstan	5.84 (+6.4%)	64.3 (-0.7pp)	99.8	3,788 (+4.1%)	14,572 (+30.3%)	3,072 (+5.6%)	13,298 (+25.4%)
Tajikistan	8.55 (+10%)	73.2 (-0.8pp)	92 (+2pp)	5,400 (+22.0%)	16,472 (+1.5%)	4,982 (-4.2%)	16,176 (-7.0%)
Turkmenistan	5.37 (+6.3%)	50 (0pp)	100 (+0.4pp)	4,305 (+50.9%)	22,500 (+43.7%)	5 (0%)*	N/A
Uzbekistan	30.49 (+7.4%)	63.6 (-0.4%)	100	12,992 (+12%)	55,563 (+13%)	1,850 (+6.9%)	6,223 (-2.7%)
Total	**67.92 (+6%)**	—	—	**47,795 (+16%)**	**207,007 (+21.6%)**	**12,584 (+4%)**	**44,497 (+5%)**

Sources: Various[1,2,3,4,5,7,9,17,18]
Notes:
a. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.
b. An asterisk (*) indicates that data are compared with countries in *WSHPDR 2013* and not in the regional summary.

Small hydropower definition

The definition of SHP varies throughout the region. Kazakhstan has the highest upper limit of installed capacity in its definition of SHP, at 35 MW, while both Kyrgyzstan and Tajikistan maintain a 30-MW limit. Turkmenistan does not have an official definition, while Uzbekistan defines SHP as up to 10 MW (Table 2).

TABLE 2
Classification of small hydropower in Central Asia

Country	Small (MW)	Mini (MW)	Micro (kW)	Pico (kW)
Kazakhstan	Up to 35	—	—	—
Kyrgyzstan	Up to 30	—	—	—
Tajikistan	Up to 30	0.1-1.0	< 100	—
Turkmenistan	—	—	—	—
Uzbekistan	Up to 10	—	—	—

Sources: *WSHPDR 2013*,[18] *WSHPDR 2016*[17]

Regional SHP overview and renewable energy policy

From the 1970s until 1990, the electricity sector in all five countries was operated through the Central Asia Integrated Power System (CAIPS), which supplied electricity and was also in charge of resolving energy and water related problems. The CAIPS generated 30 per cent of electricity from hydropower and 70 per cent from thermal power. After the economic and political disintegration of the Soviet Union, the CAIPS collapsed and national electricity systems were separated. The CAIPS treated all Central Asian republics as a single region and provided distribution of electricity regardless of national borders. With the emergence of the sovereign countries, water and power generation in the region became imbalanced. As most hydropower resources are concentrated in Kyrgyzstan and Tajikistan, electricity consumption dropped severely because resources were not spread uniformly. Kazakhstan, Turkmenistan and Uzbekistan, on the other hand, have an abundance of thermal resources such as fossil fuels. The countries undertook measures and agreed on maintaining parallel operations within the separately functioning power systems.[18]

Economic development and urbanization combined with energy independence have been an impetus for the expansion of national energy sectors, in particular, electric generation. Electrification in the region has been steadily increasing, with 100 per cent access in Kazakhstan, Turkmenistan and Uzbekistan, and more than 99 per cent in Kyrgyzstan, while Tajikistan has the lowest rate of 92 per cent.[17]

There is considerable interest from investors to develop SHP in Kazakhstan, with many new prospective projects being in the works. In 2013, the Ministry of Industry and New Technologies announced the plan for 106 green power generation projects to be implemented by 2020, including 41 SHP plants with a combined installed capacity of 539 MW (less than 35 MW), 34 wind energy plants (1,787 MW), 28 solar stations (713.5 MW), and three biofuel power plants (15.05 MW).[17]

During the 1960s, Kyrgyzstan had 66 MW from some 200 SHP plants that were all later decommissioned. With the revival of SHP in the country, the Ministry of Energy plans to build and rehabilitate 132 SHP plants with a total capacity of 275 MW (less than 30 MW), which would increase the installed SHP capacity by more than six-folds by 2025.[17]

A majority of the water resources of Central Asia originates from Tajikistan, and as such the country has one of the highest hydropower potentials in the region and in the world. As a result, the majority of the country's electricity generation comes from large-scale hydropower plants. However, due to the sparse distribution of the population, SHP plays a vital role in providing electricity access to remote rural areas.[17]

Turkmenistan is located on the world's fourth largest natural gas reserve and has vast quantities of oil resources. Its abundance in fossil fuels has resulted in an energy sector dominated by thermal generation. Although hydropower potential, including SHP, is high, there are few incentives at the moment for the development of hydropower projects.[17]

Both the Amu Darya and Syr Darya rivers flow through Uzbekistan, providing ample hydropower potential. However, due to previously built canals, which altered the

TABLE 3
Small hydropower in Central Asia (+/– % change from 2013)

Country	Potential (MW)	Planned (MW)	Installed capacity (MW)	Annual generation (GWh)
Kazakhstan	2,707 (-)	539	78 (0%)	N/A
Kyrgyzstan	900 (0%)	275	41.5 (+29.7%)	125
Tajikistan	25 (0%)	200	25.0 (+108.3%)	2.3
Turkmenistan	1,300 (-)	57	5.0 (0%)	N/A
Uzbekistan	1,180 (-32.9%)	12	71.0 (+26.1%)	N/A
Total	**6,112**	**1,065**	**220.5 (+20.9%)**	**127.3**

Sources: *WSHPDR 2013*,[18] *WSHPDR 2016*[17]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. Kyrgyzstan up to 30 MW.

river flows and have affected the Aral Sea, hydropower in general has not been widely pursued.[17]

All countries in the region are currently undergoing a period of political and economic reform, strongly influencing the situation on domestic and international scales. International organizations are supporting the development of renewable energy sources and SHP plants in Central Asia.[17]

In 2013 the European Union (EU) launched a three-year Sustainable Energy Programme for Central Asia (CASEP): Renewable Energy Sources (RES) – Energy Efficiency (EE), which was completed in April 2016. The aim of the project was to define policies for the development of RES and energy efficiency, produce tools for their development, improve the countries' access to energy resources and ensure efficient use of existing capacity and networks, disseminate the European experience in the development of RES and EE, as well as related policies, and lastly, to raise awareness of EE and RES.[14]

The UNDP/GEF Small Hydro Power Development project in Kyrgyzstan and the UNDP/GEF Technology Transfer and Market Development for Small-Hydropower in Tajikistan will close in 2016.[15,16]

These projects will significantly accelerate the development of small-scale hydropower in Kyrgyzstan and Tajikistan, as well as assist the Governments to attract investments through enabling legal and regulatory frameworks, capacity building, and developing sustainable delivery models. The projects are expected to eventually aid in decreasing the use of conventional biomass and fossil fuels for power and other energy needs.

A number of positive developments on sustainable energy can be observed in the region:

- All countries of the region, except Turkmenistan, have adopted primary legislation on renewable energy and energy efficiency. The legislation framework includes introducing incentives such as grid-access, tax exemptions and feed-in tariffs. These regulations are, however, allocated on a case-by-case basis.
- Kazakhstan has adopted a national plan on transitioning to a green economy. The plan pledges to reduce its greenhouse gas emissions as well as introduce a pilot emissions trading system. In 2017, the country will be hosting the World Expo on Future Energy, which should give an additional boost to renewable energy and energy efficiency projects.
- Uzbekistan is constructing the first grid-connected photovoltaic power plant (100 MW) in the region with a loan from the Asian Development Bank (ADB).
- Supported by the ADB, Russia, the European Bank for Reconstruction and Development, and the World Bank, Tajikistan and Kyrgyzstan are implementing several projects on SHP and energy efficiency.
- The region demonstrates a growing interest in energy efficiency measures. Kazakhstan, Uzbekistan and Turkmenistan see it as way of increasing their fossil-fuel exports, whereas Tajikistan and Kyrgyzstan hope to reduce their dependence on energy imports.[19]

Barriers to small hydropower development

While there is a significant potential for SHP in Central Asian countries, the widespread implementation of SHP is hampered by a number of barriers:

- Market barriers: There is currently a lack of awareness and information on the potential and possible application of SHP.
- Institutional and regulatory barriers: The existing institutional and regulatory frameworks in the energy sector are not fully taking into account the peculiarities of SHP.
- Technical barriers: Technical and market conditions are not supportive of implementation and operation of SHP.
- Financing barriers: There is a lack of functioning and affordable financing mechanisms (credits) available for developers of SHP projects.[10]

3.1.1 Kazakhstan

Eva Kremere, International Center on Small Hydro Power

Key facts

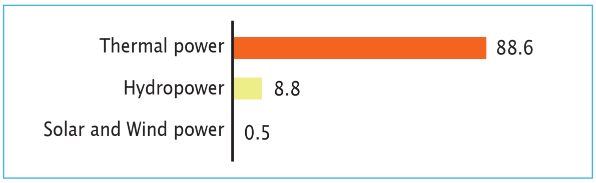
Population	17,670,579 [1]
Area	2,724,900 km^2
Climate	Continental, cold winters and hot summers, approximately 90 per cent of land has arid and semiarid climate. The average temperature in January ranges from –18°C in the north to –3°C in the south, and in July from 19°C in the north to 29°C in the south.[3]
Topography	Vast flat steppe extending 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 oases and deserts of Central Asia in the south. The highest point is Mount Khan Tengri at 7,010 metres above sea level. Most of the country lies between 200 and 300 metres above sea level.[4]
Rain pattern	Precipitation in the form of rain is insignificant, except for mountainous regions. The foothill areas receive 500-1,600 millimetres precipitation per year; the steppe, 200-500 millimetres; and the desert, 100-200 millimetres. In winter, most of Kazakhstan experiences an increase in daily maximum amount of rain.[3]
General dissipation of rivers and other water sources	Kazakhstan has 8,500 small and large rivers, with the Ural, Emba, Syr Darya, Irtysh, Ischim and Tobol as the largest, and has approximately 48,000 lakes. Water availability is 20 m^3/km^2 and is one of the lowest in Eurasia. Surface water resources are irregular in the eastern part at 34.5 per cent, the northern part at 4.2 per cent, the central part at 2.6 per cent, the south-eastern part at 24.1 per cent, the southern part at 21.2 per cent, and the western part at 13.4 per cent. The annual stream flow has perennial fluctuations. Rivers on the plains are fed by melted snow, with the biggest discharge in April and May. The highest stream flow occurs during the spring (between 80 and 90 per cent), with numerous temporal short living watercourses. The summer precipitation does not affect the river water supply.[2]

Electricity sector overview

In Kazakhstan, installed electricity generation capacity in 2015 was 21.31 GW while the available capacity was about 17.5 GW. The disparity is mainly due to the aging equipment.[6] In 2015, total net electricity generation was reported to be 91.07 TWh, which is slightly lower than the 97.9 TWh reported in 2014.[43] Given that Kazakhstan has rich gas, oil and coal reserves, electricity was mostly generated by thermal power plants, with coal generating about 70 per cent of the energy mix (Figure 1).[7] According to the World Bank Data, the country's electrification rate is 100 per cent.[5]

FIGURE 1

Electricity generation in Kazakhstan (TWh)



Source: Kazenergy (2014)[8]

The country can be divided into three major electric power production and consumption zones: northern, western, and southern. A vast portion of the country's power generation is located in the north-west region of Ekibastuz, where coal is produced and hydroelectric facilities are located.[11] The northern zone accounts for about 80 per cent of the electric power production in the country. It is also the most power-consuming zone, with a consumption rate of 70 per cent of the total electric power in the country. The western zone accounts for 12 per cent of the electricity consumption, and it depends mostly on the thermal power production; utilizing gas and other hydrocarbon fuels produced in the region. The southern zone consumes about 18 per cent of the total electricity consumption and experiences shortages of the electric power supply. These shortages are met by electricity imports from the northern regions of Kazakhstan and also from neighbouring countries.[44] At the same time, the fastest economic growth has been seen in the southern regions. For example, the growth in electricity consumption in the Almaty region in southern Kazakhstan exceeded 7 per cent per year from 2000 to 2007.[9]

According to the Government, there is a shortage of 2 TWh in generating capacity in east Kazakhstan.[10] Therefore it is necessary to develop new installed capacity particularly in the southern zone of the country. It is expected that the country will require construction of new electricity capacity, 11-12 GW by 2030 and 32-36 GW by 2050, excluding the installed capacity of renewable energy (RE) sources.[12] However, there was an economic slowdown in the first quarter of 2016. This resulted in the lowest electric power consumption in the past five years, with a decrease of 2.2 per cent in comparison with the same period in 2015.[45]

The electricity market was privatized after the country achieved statehood in 1991. In 2014, 86.5 per cent of electric power generation was within the private sector. Consumers have the flexibility to choose between providers of electric power. The country's transmission system is owned and operated by the state-owned company Kazakhstan Electricity Grid Operating Company (KEGOC) with 15 regional distribution companies in total.[6]

The electricity transmission and distribution system is divided into three networks, with two in the north connected to Russia, and one in the south connected to the Unified Energy System of Central Asia, through Uzbekistan and Kyrgyzstan. The aging electricity generation infrastructure requires upgrading, as transmission and distribution lines are inefficient, causing losses of around 7 per cent.[15]

It has been difficult to develop small hydropower (SHP) projects in remote areas due to insufficient electricity grid connections. Furthermore, electricity transmission lines connecting the regions did not have necessary capacity, resulting in great variations in electricity prices as well as electricity outages in the winter. However, the situation has steadily improved. Several big electricity grid modernization projects were developed with support from the World Bank's North-South Electricity Transmission Project (2011), Kazakhstan Moinak Electricity Transmission Project (2013) and Alma Transmission Project (2015).[16,17,18] Many new projects are also underway.[19,20,21,22]

The Government regulates transmission and distribution tariffs.[13] In October 2014, prices of electricity averaged KZT 1,100 (US$3.2) for 100 kWh, with significant variation in prices within Kazakhstan regions. For example, prices range from KZT 538 (US$1.56) for 100 kWh in Aktau to KZT 1,621 (US$4.7) in Almaty.[14]

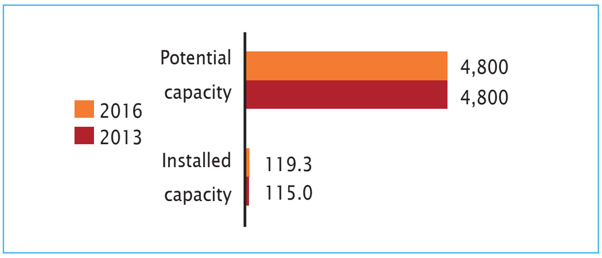
Problems with the electricity sector have been inherited from the Soviet era when Central Asia was regarded as one region and electricity infrastructure was built accordingly. Currently both the Government and international institutions are investing money in the adjustment of the electricity sector according to the country's current needs.

Small hydropower sector overview and potential

The definition of SHP in Kazakhstan is up to 35 MW.[23] The installed capacity of SHP in 2014 was 119.27 MW while the technical potential was estimated to be at least 4,800 MW, indicating that only 2.5 per cent has been developed (Figure 2). Concerning SHP for less than 10 MW, the installed capacity was 78 MW while the potential was 2,707 MW.

FIGURE 2

Small hydropower capacities 2013-2016 in Kazakhstan (MW)



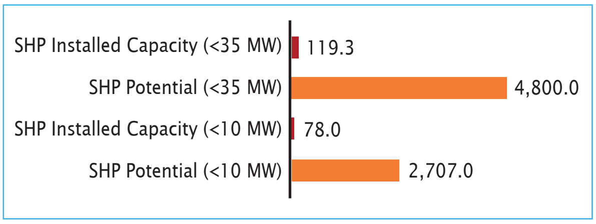
Sources: Ministry of Energy of the Republic of Kazakhstan,[41] UNDP[42]
Notes:
a. Data for SHP up to 35 MW.
b. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*; 2013 data is from UNDP.[42]

The government classification for SHP plants is units with a total capacity of no more than 35 MW and without reservoirs.[23] In 2014, hydropower accounted for about 0.5 per cent of total primary energy needs and contributed 9 per cent of the total electricity generated.[8,24]

Approximately 65 per cent of hydropower resources are concentrated on the rivers located in the mountainous southern regions of Kazakhstan. There are three major areas in Kazakhstan for hydropower development: the Irtysh River basin and its main tributaries (Bukhtarma, Uba, Ulba, Kurchum, Kardzhil), the south-eastern zone with the Ili River basin, and the southern zone with basins of the Syr Darya, Talas and Chu rivers. The gross hydropower potential of the Republic of Kazakhstan is estimated to be 170 TWh/year, while its technical capacity is 62 TWh, of which approximately 8 TWh comes from SHP of up to 35 MW.[23] In 2014 production of electricity from SHP was 558,147 GWh, while installed capacity of SHP was 119.27 MW for plants up to 35 MW, and 78 MW for plants with a capacity up to 10 MW (Figure 3).[41,46]

FIGURE 3

Small hydropower capacities in Kazakhstan



Sources: Karatayev and Clarke,[4] Ministry of Environment Protection of Kazakhstan,[26] Ministry of Energy of the Republic of Kazakhstan,[41] UNDP [42]

The Ministry of Industry and New Technologies of Kazakhstan announced in 2013 (with amendments of 2014) plans for 106 renewable energy projects by 2020 with a total capacity of 3,054.6 MW, including 41 SHP plants (539 MW), 34 wind energy plants (1,787 MW), 28 solar stations (713.5 MW) and three biofuel power plants (15.05 MW).[47] The Almaty region would rely extensively on hydropower. Between 2009 and 2014 seven new SHP plants were built.[25] By the end of 2014 there were three hydropower plant projects in construction stages, with a planned minimal capacity of 68 MW, 6.8 MW, and 3.5 MW.[27]

There is considerable interest from investors to develop SHP plants in Kazakhstan, and many new prospective projects. For example, the European company PNE announced in 2010 their plans to invest EUR 1 billion (approximately US$1.2 billion) in the construction of SHP plants in eastern and southern regions of Kazakhstan.[10] It has been estimated that construction of the PNE project and water reservoir on the river will allow use of an additional 10, 000 hectares of irrigated land.[28] Furthermore, an SHP plant will be built in Kazakhstan in collaboration with China. In 2012 RusHydro and Kazkhmys signed a tentative deal where the Russian energy conglomerate planned to construct up to 300 MW of SHP plants in Kazakhstan.[29] Plans were announced in 2014 to build six SHP plants in Almaty region with a total capacity of 30 MW.[30]

It has been difficult to attract financial support for green energy projects. However, introduction of the feed-in tariff (FIT), new legislation, and the Government's vision for a greener future in 2014 have provided new opportunities for SHP development. The European Bank for Reconstruction and Development (EBRD), international financial institutions (IFIs), and the Government agreed to channel US$2.7 billion into the country's economy. This partnership would enable the EBRD, the largest foreign investor, to significantly increase its investment in Kazakhstan in priority segments, including green energy.[34] The new legislation enabled them to start the dialogue with companies willing to look into commercial renewable power generation.[35] The remote rural areas and south-eastern regions are particularly interested in SHP projects because of energy shortages.

Renewable energy policy

In 2012, the Government identified the environment as a key priority, and plans to spend about 2 per cent of the GDP of Kazakhstan on green energy projects.[31] In line with the declared long-term economic development plan under the Kazakhstan 2050 Strategy, the country adopted the Green Energy Concept (Energy Efficiency 2020) in 2013.[12] The Strategy aims to reach an alternative and renewable energy share of 30 per cent by 2030 and 50 per cent by 2050 in the country's energy mix by modernizing ageing infrastructure, increasing the use of alternative fuels and installing efficient and environmentally friendly energy technologies.[32] In addition, it aims to reduce the level of carbon dioxide emissions in the power industry by 40 per cent by 2050.[12]

In 2009, the Parliament of Kazakhstan passed the Law on Use of Renewable Energy Sources, thus establishing a regulatory framework for renewable energies. Feed-in tariffs were introduced in 2013 under the Law on Supporting the Use of Renewable Energy Sources, with a target of achieving 3 per cent of renewable share of total energy balance by 2015 (up from less than 1 per cent in 2013).[33] The government regulation as of 12 June 2014, No. 645, approved the fixed tariffs for 2014 with a valid period of 15 years for wind, solar, SHP and biogas plants.[23] In 2014 the fixed price of one kWh for energy produced by SHP plants was set at KZT 16.71 (approximately US$0.04), which was 34 per cent higher than the average price for electricity (KZT 11, approximately US$0.03).[38,14] For wind power plants the set price was KZT 22.68 (approximately US$0.06) and for biogas plants it is KZT 32.23 (approximately US$0.09).[38]

Kazakhstan was the first in the region to start the Green Bridges Partnership Programme 2011-2020, improving access to green technology and investment.[36] Moreover, Kazakhstan plans to host Expo 2017, Future Energy, in which it will be able to demonstrate modern energy technologies and raise awareness of sustainable development prospects. In general, recent developments could indicate a change away from thermal energy dominated sector.

Barriers to small hydropower development

Kazakhstan is rich with renewable energy resources, in particular solar, hydro, biomass and wind. However, only a small fraction of this potential is currently being exploited. The power sector has been characterized by a significant deterioration of its generation and network equipment, the dominant position of coal generation, and the absence of necessary reserves to cover peak demand. Imperfection of both tariff and pricing policies for energy resources systems further compounds the issue in Kazakhstan. However, recent changes in legislation now promote new projects to modernize the power industry and enable a greener energy future.

The development of SHP in Kazakhstan is hampered by a number of barriers:

- Problems with data collection. This is related to the inability to collect information on the use of conventional and unconventional renewable energy and off-grid developments. This information is needed for developing energy policies which would take into account all current and prospective developments in the energy sector and help design a sustainable strategy with various energy mix options.[33]
- Lack of an effective project plan and delivery, as well as lack of experts in RE sector; projects tend to end up much more expensive than initially planned.[39]
- Lack of regulation of technical specifications, particularly in regards to the power grid connection.
- The challenge of transporting renewable energy generated electricity through the transmission system and to the consumption centres of the country.[37]
- There have been seven different ministries in charge of power sector of Kazakhstan since 1991, often with poor knowledge handover. This has created confusion and weak fulfilment of plans.[39]

3.1.2 Kyrgyzstan

Eva Kremere, International Center on Small Hydro Power (ICSHP)

Key facts

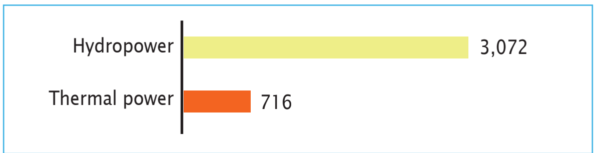
Population	5,836,000[1]
Area	199,900 km^2 [2]
Climate	Continental climate with cold winters and hot summers. Absolute temperatures vary from -57 °C to 43 °C in summer.[3]
Topography	Kyrgyzstan is a landlocked, largely mountainous country with the Tian-Shan mountain range covering approximately 95 per cent of the territory. About 94 per cent of the land rises above 1,000 metres above sea level and 40 per cent is at more than 3,000 metres above sea level. The highest point is Pik Pobedi at 7,439 metres above sea level. Glaciers cover about 4 per cent of the territory. The Fergana mountain range separates the country into the mountain area in the east and centre and the Fergana valley in the west and south-west. There are also lowland areas near the border with Kazakhstan in the north.[3]
Rain pattern	The highest annual rainfall is on the western slope of the Fergana ridge (over 1,000 mm), the lowest on the western side of the Issyk-Kul basin (150 mm). Average rainfall ranges from 533 mm. Most of the precipitation falls as snow during the period from October to April.[3]
General dissipation of rivers and other water sources	The water resources in the territory of Kyrgyzstan are unevenly located as most are concentrated in the unpopulated and economically underdeveloped areas. The country can be divided into two hydrological zones: the flow generation zone in the mountains, which covers 87 per cent of the territory, and the flow dissipation zone. With most rivers being fed by glaciers or snow, the peak flow occurs in the months of April to July. The Syr Darya (Naryn) River basin is the largest in the country and covers 55.3 per cent of the country. Other important rivers include the Chu, Talas, Assa, Aksu, Aksay, Kek Suu and Amu Darya. Kyrgyzstan also has the world's second largest crater-lake Issyk-Kul.[3]

Electricity sector overview

The total installed electricity generating capacity in 2013 was 3,788 MW (Figure 1).[6] Electricity generation varies from 12 TWh to 15 TWh depending on the yearly water flow of the Naryn River.[7] It was 14.57 TWh in 2014 (while only 10.9 TWh in 2009), including 13.3 TWh produced by hydropower and 1.27 TWh by thermal power plants (Figure 2).[45]

FIGURE 1

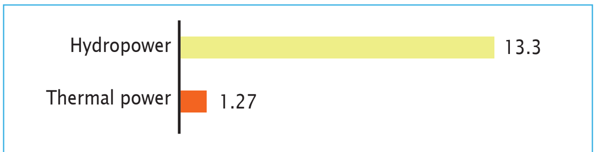
Installed electricity capacity in Kyrgyzstan by source (MW)



Source: Ministry of Energy of the Kyrgyz Republic[6]

FIGURE 2

Electricity generation in Kyrgyzstan (TWh)



Source: National Statistical Committee[45]

As of 2013 there were 21 power plants, of which 19 were hydro (3,072 MW) and 2 were thermal power plants (716 MW) in the Kyrgyz Republic.[6] The largest hydropower plants are Toktogul hydropower plant (HPP), with an installed capacity of about 1,200 MW, and Kurpsai HPP, with an installed capacity of about 800 MW.[10] The thermal power plants in Kyrgyzstan are fuelled by gas, fuel oil, and coal. The distribution system has a relatively high technical loss and low construction quality,[12] mostly due to the fact that the generating capacity was built 30 to 50 years ago.[13] As a result, about 30 per cent of the network needs to be repaired or replaced.[5] In 2013 the total electricity loss was 17.9 per cent compared with 22.3 per cent in 2011.[10] The loss was also partly due to inefficient bookkeeping systems which made corruption and power theft relatively easy and risk free.[12] As such, there was planned rehabilitation scheduled for the Toktogul HPP and several other hydropower plants in 2014.[19,20,21]

The political situation in the Kyrgyz Republic has not been stable, and for long periods there was social resistance to the disproportionate distribution of resources and impoverishment, mainly in rural areas.[14] The economic situation had been promising in 2013, with a GDP increase of 7 per cent, but GDP growth in 2014 and 2015 was expected to slow down to only 4.5 per cent. This expectation was mainly due to the impact of the 2014 economic slowdown in Russia, slower growth of gold mining, and the fragilities of the banking sector.[15] Kyrgyzstan remains largely dependent on imports of fossil fuels from Uzbekistan and Kazakhstan, creating energy security concerns.[8,9,11] Between 2005 and 2013, gas prices increased by more than six times which put significant pressure on the electricity system.[12,13]

Regulation of the energy sector is implemented by the Government through the State Property Fund and the Ministry of Energy and Industry. The State Property Fund acts as the owner and manager of state-owned power companies. The Ministry of Energy and Industry is responsible for industry development, including strategic planning, policy development, and forecasting.[18] In 2014 there were six state-owned electricity companies, which were successors of the national electric company Kyrgyzenergo unbundled in 2001. In 2014 there were no independent power producers except for some small hydropower (SHP) generators.[16] The electrification rate in the Kyrgyz Republic is 99.8 per cent.

With fast economic growth, increasing demand of electricity and aging infrastructure, the country must seek to add to its capacity. In 2014, electricity demand was approximately 200 GWh higher than domestic generation.[46] In 2015 total generation capacity was estimated to be only 11.6 TWh, while energy consumption was expected to increase by 1.5-2 TWh per year, reaching 15.8 TWh by 2015. The necessary additional capacity in 2015 would be 480 MW and could reach 720 MW in 2017.[13] According to the National Energy Program, by 2025 electricity production must be doubled and increased to 30 TWh.[22] The Government has made plans to implement additional capacity of 640 MW by 2018 that includes: construction of Kambarata-2 HPP (about 100 MW, to be completed in 2016), reconstruction of Bishkek thermal power plant (TPP) (about 300 MW; 2016-2017), construction of the Upper Naryn cascade (about 240 MW; 2016-2018).[13] The master plan to develop large HPP on the Naryn river dates back to the Soviet period, and has created worries in downstream countries.[12,23]

The electricity infrastructure in the Kyrgyz Republic was built in the Soviet era, when Central Asia was treated as one region. Current infrastructure is aged and inefficient, and needs modernization. Seasonal variation of the electricity load has a ratio of 3:1 between the month of the highest demand (January) and the lowest demand (May). Overloading the systems in order to meet the high winter demand has accelerated the deterioration process and increased the number of service interruptions.[5] Electricity and heat tariff levels did not cover the cost of providing services, leading to poor investment in the sector.[24] Outages have been especially troubling for the poor, as one third of them use electricity for heating and over three quarters use it for cooking.[12,25] Poverty has been more evident in rural areas, where 76.4 per cent of the poor live.[14] The number of power outages declined by almost a quarter between 2011 and 2013.[10] Farmers living in mountainous areas were still not grid-connected, therefore mini and micro hydropower projects are run by individual efforts in rural areas.[5,38]

The electricity price remained relatively constant at KGS 0.7 (approximately US$0.01/KWh) from 2001 to 2014; it carried out a social security function, similar to the Soviet practice. Tariff increases had not been implemented in the past due to the fear of social unrest (as in 2010).[26] However, in November 2014 after a public discussion, Resolution No. 660 came into force which approved the Medium-Term Tariff Policy of the Kyrgyz Republic for Electric and Thermal Energy, 2014-2017.[27] This introduced the first electricity price increase, valid as of 11 December 2014.[28] It set the price of KGS 0.7 per kWh (approximately US$0.01/kWh) for the consumption up to 700 kWh/month; above this limit the price is calculated as taking into account the actual cost of electricity of KGS 1.2 per kWh (approximately US$0.02/kWh) and the cost of imported electricity of KGS 5.13 per kWh (approximately US$0.087/kWh).[13] According to the Resolution, the next price increases were planned for 01 April 2015, 2016 and 2017: the price would increase by 20 per cent annually, resulting in the rate of KGS 1.21 per kWh (approximately US$0.02/kWh) in 2017.[27] It was estimated that about 463,000 people did not consume electricity above the set limit.[29] Tariffs are differentiated for six customer classes.[18]

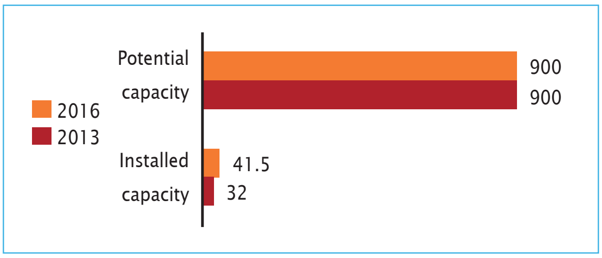
The power sector needs great financial investment, but so far it has been losing money and has accumulated large amounts of debt due to low electricity tariffs and high electricity losses. It has been difficult for electricity companies to obtain financial help from any sector, whether commercial or public. However, there are some ongoing projects to modernize transmission lines.[20,30] The State remains the owner of all the major energy companies and has created a situation where it lends money to itself. Therefore, cancelling at least some of debt as part of prospective restructuring solution could be considered.[12]

Small hydropower sector overview and potential

The definition of SHP in Kyrgyzstan is up to 30 MW. The installed capacity of SHP is 41.5 MW while the economic potential is estimated to be 900 MW, indicating that approximately 5 per cent has been developed. Between *World Small Hydropower Development Report (WSHPDR) 2013* and *WSHPDR 2016*, the installed capacity increased by almost 30 per cent, whereas the estimated potential has not changed (Figure 3).

FIGURE 3

Small hydropower capacities 2013-2016 in Kyrgyzstan (MW)



Source: Ministry of Energy of the Kyrgyz Republic[6]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016.*

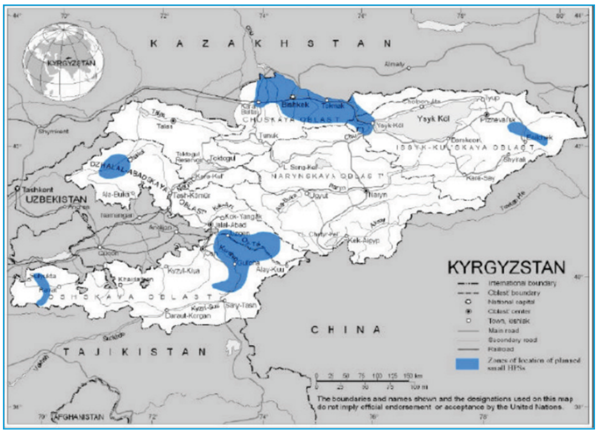
According to the Law on renewable energy sources, the local classification of SHP is plants under 30 MW.[6,31] Total hydropower generation capacity in 2013 was 3,071 MW, while estimated potential was 18,500 MW. In 2013 there were 12 SHP plants with total installed capacity of 41.5 MW, and yearly electricity generation of 125 GWh.[6,32] Potential for SHP up to 10 MW is estimated to be 275 MW, but for plants up to 30 MW it is between 570 and 900 MW.[6,33,34]

In the 1960s there were 200 SHP plants with a total capacity of 66.3 MW, unfortunately they were decommissioned or replaced by large ones according to the Soviet Union strategy. The current government plans to redevelop SHP in the country. The concept of SHP development in Kyrgyzstan in 2015-2017 was approved on 20 July 2015 by the Kyrgyz Republic Government Decree No. 507.[47]

It is estimated that there are more than 80 available sites for SHP up to 10 MW, while for plants up to 30 MW there are around 200 sites on 172 rivers, with total capacity of 80 TWh and technical potential of 5-8 TWh per year.[35,6] Many locations suitable for SHP have maintained dams, channels and other facilities from SHP plants previously located there.[12] The largest SHP potential is concentrated in the northern, southern and eastern areas (marked with blue, Figure 4).[33]

FIGURE 4

Map of locations of small hydropower potential in Kyrgyzstan



Source: Global Environmental Facility[33]

According to the Ministry of Energy of the Kyrgyz Republic, there is a plan to build and rehabilitate 132 SHP plants with a total capacity of 275 MW (Table 1) between 2010 and 2025.[7] In line with the project Strategic Planning for Small Hydropower Development in the Kyrgyz Republic, which will last until 2017, four SHP plants will be built. Feasibility studies were already carried out in 2014 and projects were proposed to investors for implementation:

- Orto-Tokoiskaya HPP in the Issyk-Kul region – 20 MW; US$25 million;
- Oi-Alma HPP in the Osh region – 17.7 MW; US$18.4 million;
- Sokulukskaya HPP in the Chui region – 1.5 MW; US$3.3 million;
- Toktogulskaya HPP in the Batken region – 3 MW; US$2.6 million.[6,22]

TABLE 1

Planned development of SHP (2010-2025)

	Number	Capacity (MW)	Generation (TWh)
Rehabilitation of existing SHP	33	22	100
Construction of new SHP:			
SHP located at water reservoirs	7	75	220
At river stations	92	178	1,200

Source: Ministry of Energy of the Kyrgyz Republic[6,7]

In the economic analysis provided by the Ministry of Energy, the estimated payback period for the four SHP mentioned above, based on the current and planned electricity tariffs, is as follows:

- With the tariff rate of KGS 0.7 (US$0.012) the payback period over 50 years;
- With the tariff rate of KGS 1.26 (US$0.021) the payback period from 17 to 21 years;
- With the tariff rate of KGS 1.32 (US$0.022) the payback period from 15 to 20 years;
- With the tariff rate of KGS 2.25 (US$0.038) the payback period from 6 to 9 years.[6]

The Law on Renewable Energy Sources states that the Government should set renewable energy (RE) tariffs, ensuring return on investment for projects within eight years.[31] However, the current electricity tariffs and low feed-in tariff (FIT) demonstrate that the law is not being implemented. As a result, all other related resolutions are also ineffectively implemented. For example, if Resolution No. 660 is implemented as planned, in 2017 the electricity price will be only KGS 1.21 (US$0.02).[6,27]

Starting from 2010, there was an inflow of investments into the electricity sector that were directed at new hydropower plant construction and electricity distribution.[36] The project Development of Small Power Producers implemented jointly with the UNDP performed feasibility studies for five other potential SHP projects.[6] One of them in Toguz-Bulak is expected to employ 20 people and provide new farmlands with water to be used by 1,000 families living in surrounding villages.[35] Also, several foreign investors showed interest in developing SHP in Kyrgyzstan.[35,37] However, according to the European Bank for Reconstruction and Development (EBRD) the business environment was still challenging, despite some improvement made by the Government.[15]

The acceptance of renewable energy and SHP are the highest in areas without electricity supply, or with unreliable electricity supply. Rural preference is to be connected to the grid rather than to an isolated SHP; connecting an isolated SHP can be problematic due to distribution companies placing obstacles for interconnection, unless their potential customers are directly connected to the generator.[17] Nevertheless, with the further deterioration of the grid, the acceptance of isolated SHP could increase.[5] Kyrgyzstan officially promotes development of RE and has signed most of the relevant international treaties. The Government, however, has made the most applicable laws and regulations to focus on relatively large hydropower development. The obstacles caused by missing legal frameworks are difficult to manage for potential small independent power producers; therefore, the small-scale potential remains currently untapped.[5,4,35,44] The estimated use of renewable energy from small power plants in the Kyrgyz Republic is less than 1 per cent.[6]

Renewable energy policy

The country's key long-term policies for the energy sector were the National Energy Programme and the Strategy for the Fuel and Energy Sector Development for 2008-2010, with an outlook to 2025.[16,43] In January 2013 the National Sustainable Development Strategy for 2013-2017 was adopted.[39] Afterwards the Energy Sector Reform Action Plan for 2013-2014 was approved on 24 July 2013, with plans to reform and ensure better regulation of the energy sector.[20] In the Kyrgyz Republic, the development of SHP and other renewable energy resources have been of high importance for many years, but so far hardly any national plans have been consistently fulfilled.[4]

The main laws of primary energy sector legislation affecting the electricity sub-sector and RE sources are:

(a) Law on Energy of the Kyrgyz Republic, adopted on 30 October 1996, No. 56, since then amended three times, the most recent being on 16 May 2008. It contains a delegation of norms which allows the Government and the Authorized Government Body in the Energy Sector to exercise significant powers.[12]

(b) Law on Electricity, adopted on 28 January 1997, No. 8, since then amended nine times.[12]

(c) Resolution No. 660. Adopted on 20 November 2014 of the Medium-term tariff policy of the Kyrgyz Republic for electric and thermal energy, 2014-2017 sets new electricity tariffs.[27]

(d) Law of Kyrgyz Republic on renewable energy sources as of 31 December 2008, No. 283, supports RE development and includes main RE definitions.[31] Amendments were made in terms of tariff surcharges for each type of RE source.[6] Accordingly, tariffs for electricity generated by RE sources for the period of the project payback were adjusted and increased as a multiple of the existing electricity tariff:
   (i) For hydropower (up to 30 MW) the rate was 2.1 times the tariff;
   (ii) For solar energy the rate was 6.0 times;
   (iii) For biomass the rate was 2.75 times;
   (iv) For wind power the rate was 2.5 times;
   (v) For geothermal energy the rate was 3.35 times.[6]

The increase of electricity prices and the introduction of special RE tariffs is a good sign that reforms in the energy sector will be carried out. However there is still long way to go before favourable terms for SHP development will be created. The Ministries are institutionally weak due to both economic and political difficulties, and coordination of joint activities is difficult due to high staff rotation. After multiple ongoing reforms, the form of public administration has changed, but the methods used by authorities in their work, decision-making and implementation have largely remained unchanged.[14]

Barriers to small hydropower development

Seasonal changes in hydropower production, hydrocarbon import and high losses due to the aged infrastructure remain important challenges for the future SHP development.[16] While the large hydropower potential is being developed, there is not sufficient interest among private investors to develop smaller projects. The main obstacle is the legal and regulatory framework, including low tariffs and obtaining licenses for construction and operation. Recent initiatives of the Government towards the tariff increase, privatization of some energy facilities and climatic changes might improve the situation.[5,12]

The key barriers to SHP development are manifold:

- Due to seasonality, streams are more likely (than larger rivers) to freeze in winter. As a result, facilities may be inoperable during the winter, when power and heat are greatest in demand and central grids are unable to compensate. Many communities are connected to the grid during the summer, when power is relatively abundant; therefore, the demand for off-grid power is not high. This leads to unfavourable economic conditions for commercial SHP plants.[40]
- Lack of clear framework conditions for investors and clear regulations on licensing; difficulties with obtaining permissions to join the electrical grid and approval of water usage schemes; complicated procedures for land usage. Regulatory documents often lack enforcement mechanisms.[6,35]
- Lack of financial resources and low financial support from the State.[35,41]
- Low prices for traditional energy.[41]
- Old electricity infrastructure due to the lack of maintenance and investment. High technical and commercial losses caused by theft, fraud and non-payment of bills.[42]
- The technical capacity of local companies in terms of SHP construction and maintenance (including spare parts) needs to be improved. Also, there is a lack of qualified specialists in the field of RE.[6,40]
- Poor information support for renewable energy, outdated information.[33]
- Low awareness of people, governmental agencies, organizations and institutions about the benefits of renewable energy. Due to energy shortages, the Government is more likely to promote larger projects to resolve the problem faster.[5,6]

3.1.3 Tajikistan

Furkat T. Kadyrov, TajHydro

Key facts

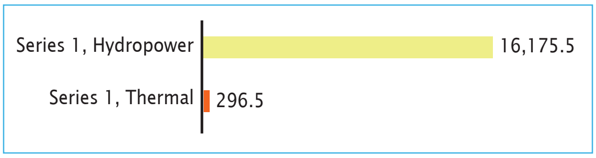
Population	8,547,400 [1]
Area	143,000 km² [2]
Climate	Continental climate with wide variations in altitude. Average temperature ranges from 7 °C in winter to 18 °C in summer. The recorded absolute maximum temperature is 48 °C in July and absolute minimum is -49 °C in January.[2]
Topography	Tajikistan is a landlocked country, with mountains covering 93 per cent of the territory. The regions of Sughd in the north and Badakhshan in the east are separated from the rest of the country by high mountain ranges and in winter can be isolated from the centre and south. The Pamir mountains located in the east make part of the Himalayan mountain chain, with the Ismoili Somoni peak at 7,495 metres being the highest point. Most of the country is at more than 3,000 metres above sea level, with a few valleys in the centre and the Fergana valley in the north.[2]
Rain pattern	Most precipitation occurs in winter from September to April. Average annual rainfall is 691 mm, with less than 100 mm in the south-east of the country and up to 2,000 mm in the centre.[2]
General dissipation of rivers and other water sources	The country's hydrographic network includes more than 25,000 rivers accounting for 69,200 km of total length. There are 947 rivers of a length from 10 to 100 km, 16 rivers of 100-500 km and 4 rivers longer than 500 km. The average annual river flow is 56.2 km³.[4]

Electricity sector overview

The electrification rate in Tajikistan is more than 92 per cent. However, the country still faces severe shortages of electricity. Around 73 per cent of the population resides in rural areas, but those areas account for merely 8-11 per cent of the total electricity consumption. The capital of Tajikistan, Dushanbe, and the aluminium industry consume most of the electric power in the country (in 2015 73.1 per cent and 20.4 per cent).[15] Hydropower contributed about 98 per cent of total electricity production in 2014 (16,472 GWh), clearly indicating the importance of hydropower in Tajikistan (Figure 1).

FIGURE 1

Electricity generation by source in Tajikistan (GWh)



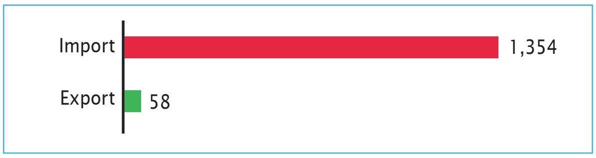
Source: TajHydro[15]

Most of the electricity generation comes from large hydropower plants while small hydropower (SHP) represents only a small fraction of the total. However, due to the sparsely distributed population, SHP and especially micro and mini hydropower have an invaluable impact on the socio-economic life of rural Tajikistan.

Additionally, in 2015, 1,354,132 GWh of electricity was imported and 58,161 GWh exported (Figure 2).[15]

FIGURE 2

Electricity import/export in Tajikistan (GWh)

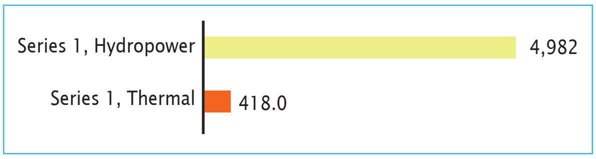


Source: TajHydro[15]

In 2014 the country's total installed capacity was at 5,400 MW, with hydropower accounting for 92 per cent and thermal power for 8 per cent (Figure 3).[20]

FIGURE 3

Installed electricity capacity in Tajikistan by source (MW)



Source: Kholmatov[20]

Tajikistan has the highest hydroelectric potential in Central Asia, due to many large glaciers and mountain streams covering almost the entire territory of the republic. According to preliminary calculations, the potential of

TABLE 1

Renewable energy resources of Tajikistan

Resources	Gross potential	Technical potential	Economic potential
Hydropower in total	179.2	107.4	107.4
Including SHP	62.7	20.3	20.3
Solar	4,790.6	3.92	1.49
Biomass	4.25	4.5	1.12
Wind	16.3	10.12	5.06
Geothermal	0.04	0.04	0.04
Total (excluding HHP)	**5,053.09**	**146.28**	**135.41**

Source: Tajik Technical University, Khujand Politechnical Institute[18]

renewable energy resources in the Republic of Tajikistan is equivalent to millions of tons of fuel (Table 1).

The state-owned company Barqi Tojik has a monopoly over energy in the country and deals with the maintenance of electric power stations and networks, manufacturing, transmission, distribution and selling of electricity.

The company is currently undergoing a restructuring and unbundling process initiated by the Asian Development Bank. It is planned that by 2018, Barki Tojik will be divided into three independent companies responsible for production, distribution and transmission of electricity in Tajikistan.[11]

The Republic of Tajikistan is currently addressing issues related to the improvement of reliability and constant access to electricity and heat. However, the vast, mountainous and remote areas of the country, usually with small, scattered settlements do not have access to electricity. Therefore a new programme to develop the SHP sector has been launched. This programme will offer the most efficient and cost-effective way of supplying power to consumers in these districts of the republic through 2020. One of the main objectives of the programme is to attract investment and create more favourable conditions for investors to utilize the potential of hydropower resources such as small rivers and streams available in all regions of the country and other renewable energy sources.

Nevertheless, with the growing number of SHP plants and other renewable energy systems, competent and cost-effective management of these facilities is becoming an increasingly important issue. The Republic of Tajikistan possesses a considerable potential for many types of renewable energy sources such as:

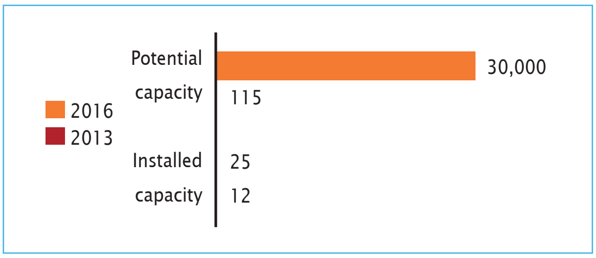
- Solar energy: Annual duration of sunshine in the country ranges from 2,000 to 3,000 hours a year. To ensure that low-income families, health facilities, education, war and labour veterans have access, with the support of the Government of the Republic of Tajikistan, in 2009-2014, 2,433 units of solar systems with a total installed capacity of 88.7 kW were delivered to 13 remote areas.
- The Ministry of Energy and Water Resources of the Republic of Tajikistan, in cooperation with experts from the Asian Development Bank, conducted a survey to study the possibility of installing solar panels in all remote areas. As a result, feasibility studies for the installation of solar panels in 138 villages have been prepared.
- Wind power: One of the most promising renewable energy sources in the country. Wind turbines require a wind speed of at least 5 m/sec. Therefore the use of wind energy in Tajikistan is advantageously carried out only under careful examination and with feasibility studies. In this regard, as an experiment, in the villages Uchkul, Miskinabad and Bungakien in Shuroobod and Faizobod districts, 'Barki Tojik' and individuals installed nine wind turbines with a total installed capacity of 5.1 kW with investments from international organizations.

Small hydropower sector overview and potential

The definition of SHP in Tajikistan is up to 30 MW. At the end of 2014, the installed SHP capacity of Tajikistan was 25 MW. The potential for SHP is estimated to be more than 30 GW and only less than 0.1 per cent has been developed.[15] The installed capacity has increased by 108 per cent between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016,* while the estimated potential has significantly increased (Figure 4).

FIGURE 4

Small hydropower capacities 2013-2016 in Tajikistan (MW)



Sources: Tajhydro,[15] Avesta.tj,[19] *WSHPDR 2013*[16]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016.*

TABLE 2

Installed small hydropower capacity in Tajikistan

Region	Total SHP plants		Active SHP plants			Non-active plants	
	Number	Total capacity (kW)	Number	Capacity (kW)	Generation (MWh)	Number	Capacity (kW)
GBAO	35	3,432	15	725	497.8	20	2,707
Khatlon Oblast	8	2,185	—	—	—	8	2,185
Sughd Oblast	38	1,882	37	1,002	460.3	1	880
Districts of Republic Subordination	74	4,685	53	2,959	1,370.2	21	1,726
Total	**155**	**12,184**	**105**	**4,686**	**2,328.3**	**50**	**7,498**

Source: TajHydro[8]
Note: GBAO – Gorno-Badakhshan Autonomous Province; data is from 2011.

The government-facilitated programmes of renewable energy development as well as construction of SHP plants in the period of 2016-2020 are meant to increase access to electricity in the remote areas of the country while accelerating economic and social development. The potential capacity of small and medium-sized rivers of the republic suitable for construction of SHP plants is more than 30 GW, with an annual power generation of about 100 GWh per year. Consistent development of RE resources will not only contribute to the solution of the social and environmental problems resulting from the population growth, but will also significantly improve food security and the economy.

According to the Law of the Republic of Tajikistan on the Use of Renewable Energy Sources in 2010, hydropower is classified as micro if the installed capacity is below 100 kW; mini hydro if the installed capacity is from 101-1,000 kW; and SHP if the installed capacity is from 1,001 kW-30 MW. In 2014 there were 316 SHP plants with a total capacity of 25 MW. However, about 200 of them were not operational during the winter. According to TajHydro, in 2011 there were 155 SHP plants within four regions (Table 2 and Figure 3). Technically, small-scale hydropower in Tajikistan revolves around micro- and mini-hydropower, due to the low population density in rural areas.

Most villages of the country are close to at least one water flow and therefore it has been possible to develop off-grid small to micro hydropower plants for the local communities, providing electricity especially during winter when national electricity supply is mostly intermittent. Most rivers in Tajikistan are characterized by high currents, and thus rarely freeze. These rural SHP systems are made mostly from spare parts, and are not periodically maintained. This causes inefficiency and frequent breakdowns. Since there are no alternatives for the local communities, such off-grid schemes are still being used and their limited resources are pooled to cover operations and maintenance expenditures.

Since 2002, PamirEnergy has invested over US$37 million in maintaining the electrical infrastructure and developing SHP in the Gorno-Badakhshan Autonomous Province (GBAO). PamirEnergy has been providing electricity to 85 per cent of the province's population and is now managing all power generation, transmission and distribution in the region.

The major part of water resources of Central Asia originate from Tajikistan (53 per cent), hence the country has one of the highest hydropower potentials in the world, estimated to be around 140 GW, with a potential annual electricity generation of 527 TWh.[10] Technical hydropower potential amounts to 317.82 TWh and the total potential of SHP up to 30 MW is 184.46 TWh per annum. Tajikistan is home to 4 per cent of the world's hydropower potential.

Recently conditions for SHP development have become more favourable. According to TajHydro's Small Hydro Power Development Centre, preliminary research shows that 900 small-scale schemes, each with output between 100 kW and 3,000 kW are technically feasible and economically efficient. Use of SHP has been acknowledged by experts to be able to meet 50-70 per cent of rural areas' energy demands and in some cases 100 per cent, based upon the presence of small rivers in predominantly mountainous areas.

In the long term, small, medium and large-sized hydropower plants in Tajikistan have the potential of boosting the country's economy through electricity export, as well as meeting reliable domestic electricity needs. The United Nations Development Programme (UNDP) has been implementing several projects in collaboration with the Government of Tajikistan and has developed three strategic documents to confront poverty issues and ensure development progress highlighting the use of SHP, namely:

- Intermediate Strategy for Renewable Energy Sources-based Integrated Rural Development (2010);
- National Program for Renewable Energy Sources-based Integrated Rural Development – National Scaling Up (October 2010);
- Energy Efficiency Master Plan (January 2011).

The UNDP has also designed a National Trust Fund for Renewable Energy and Energy Efficiency in Tajikistan.

TABLE 3

Planned small hydropower plant capacity in Tajikistan, 2009-2020

Period	Planned total installed grid connected capacity (MW)	Additional standalone capacity (MW)	Planned annual electricity production from the installed capacity (MWh/year)	Required money to incentivize newly installed capacity in given period (US$)	Total required money in the given period for incentives (US$)	Required money to cover investment costs of stand-alone plants (US$)
2009-2011	43.53	5.00	280.84	5,616,868	5,616,868	5,000,000
2012-2015	32.85	18.62	185.07	3,701,344	9,318,212	18,620,000
2016-2020	26.80	73.20	175.74	3,514,706	12,832,918	73,199,000
Total (2009-2020)	**103.18**	**96.82**	**641.65**	**12,832,918**	**27,767,998**	**96,819,000**

Source: Morvaj[13]

Once the transmission networks to Afghanistan and Pakistan, have been completed, Tajikistan will be able to enhance profitability by trading with these countries. A preliminary assessment of finance required to incentivize SHP development for the period of 2009-2020 is shown in Table 3. Furthermore, the UNDP's Energy and Environment Programme project Technology Transfer and Market Development for Small Hydropower in Tajikistan in collaboration with the Global Environment Facility, started in March 2012 will be running until December 2016.[14]

The International Finance Corporation (IFC) is working closely with the Ministry of Energy and Water Resources to promote off-grid SHPs. A few projects, such as Haftkul 1 and Haftkul 2, were presented to the Ministry in 2015. The attractiveness of off-grid solutions is that the tariff for electricity is three times higher and a private off-taker is a guarantee of timely payments.

During the Soviet Union, Tajikistan together with Kyrgyzstan provided hydropower to Kazakhstan, Turkmenistan and Uzbekistan in the summer; and in turn they received gas and electricity during the winter. However, with the collapse of the Soviet Union, the advantageous relationships and mutual dependency in the region also ended. The lack of coordination gave rise to tensions between the countries and in the last decade, water rights have been contested. For example, water infrastructure projects, including the development of hydropower capacity, represent a complex issue related to the rights of downstream water users, especially in Uzbekistan and Turkmenistan. Both of these countries depend on water from the Amu Darya for irrigation purposes.

Renewable energy policy

Electricity supply in Tajikistan is unreliable, and the population experiences constant power cuts. However, the potential to utilize renewable energy is tremendous, with SHP as the top priority for development and solar and wind following as potential energy sources. The Law of the Republic of Tajikistan on the Use of Renewable Energy Sources (RES) was adopted in 2010, regulating legal relations between public authorities and stakeholders in the area of priority and effective use of renewable energy with an emphasis on international cooperation.

It is also aimed at increasing the level of energy conservation, reducing the anthropogenic impact on the environment and climate, as well as saving and conserving non-renewable sources of energy. The Energy Law was amended in 2007. Both the law on Energy (2007) and the law on RES (2010) enable the selling of electricity generated from RES to the grid.

Barriers to small hydropower development

There are fewer barriers for the off-grid and captive power SHP plants, where electricity is produced for one or few consumers who are not connected to the main transmission lines. These consumers do not depend on Barki Tojik, and thus there is less need for private producers of electricity and private buyers to obtain approvals and licenses.[19]

The barriers to SHP development in Tajikistan include:

- Lack of reliable data on SHP potential and ways to use renewable energy;
- Low residential electricity tariffs;
- Uncertainty about private sector participation, independent power producers as per the legal and regulatory framework;
- Monopoly in the energy market;
- Lack of financing; underdeveloped mechanism to effectively attract and manage resources from donors or state-funded support for decentralized renewable energy development;
- Lack of local expertise in project development and maintenance of SHP plants and equipment;
- Lack of awareness on the potential significance of SHP technology for reducing winter energy insecurity, as well as the use for reducing forest wood resources for heating purposes.

3.1.4 Turkmenistan

Eva Kremere, International Center on Small Hydro Power (ICSHP)

Key facts

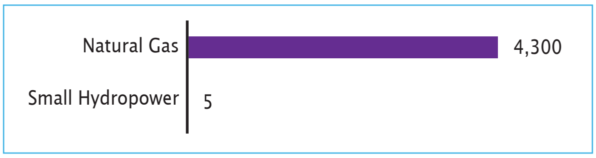
Population	5,374,000[1]
Area	491,210 km[2]
Climate	Continental and very dry climate, with very hot and mostly dry summers and moderate winters with frequent rains but rare snow. From May to September temperatures can often be higher than 40°C, whereas the average temperature in January is between -6°C and 4°C.[2]
Topography	Over 80 per cent of the total territory is occupied by the Kara Kum desert, which is bounded by the Murgab, Tejen, and Atrek rivers in the south and by oases in the north that are watered by the Amu Darya. The highest point is Mount Ayrybaba (3,139 metres), located in the east near the border with Uzbekistan. Only 4 per cent of the country's territory is arable, with approximately 2.5 per cent under irrigation.[3]
Rain pattern	Average annual rainfall is 210 mm. Rainfall peaks in March, with 44 mm, and reaches its lowest point in August, with 1 mm, on average.[4]
General dissipation of rivers and other water sources	Main rivers are located in the far south and far east of the country. The Amu Darya having a total length of 2,540 kilometres is the longest river in Central Asia and the most important river in Turkmenistan. The river flows into the Aral Sea but it has been severely affected by damming and irrigation uses of the Amu Darya. The river's average annual flow is 1,940 m³/sec. Other major rivers are the Tejen (1,124 km), the Murgap (852 km), and the Atrek (660 km).[5] The most important waterway in the country is the Kara Kum canal that brings water from the Amu Darya, Murghab and Tedzhen rivers to the densely populated southern region allows the irrigation of more than 1 million hectares of land.[6]

Electricity sector overview

The electricity sector, controlled by the Ministry of Energy and Industry of Turkmenistan, is fuelled almost entirely by natural gas.[11] The total installed available capacity in 2014 was approximately 4.3 GW including 5 MW from small hydropower (SHP) (Figure 1).[26,27] By February 2016, the total installed capacity increased to 5,178.4 MW from 12 state-owned power plants.[31] The electrification rate was 100 per cent in 2014.[22]

FIGURE 1

Installed electricity capacity by source in Turkmenistan (MW)



Sources: UNDP,[26] EIA[27]

Electricity production from hydropower in 2010 was 0.02 per cent (approximately 3 GWh) of the total generation. Its highest value over the past 20 years was 4.8 per cent in 1990, while its lowest value was 0.02 in 2010.[13] In 2015, Turkmenistan produced 22.5 TWh of electricity.[33] Natural Gas consumption accounted for approximately 80 per cent, and petroleum-based consumption represented the remaining 20 per cent. Domestic electricity consumption falls below the country's gross generation allowing the country to export the remaining production. Turkmenistan is linked to the Central Asian electricity grid and exports electricity to other Central Asian countries as well as to Afghanistan, Iran and Turkey.[29] The electricity sector in Turkmenistan is a monopoly and is managed by the state-owned Turkmenenergo State Corporation which owns all electricity generating plants, along with transmission and distribution facilities.[11]

Turkmenistan had an estimated 600 million barrels of proven oil reserves as of January 2015. The country's estimated oil production in 2014 was 238,000 barrels per day.[29] Due to these massive reserves the Government has provided the population with free monthly quotas on electricity, natural gas, water, salt and gasoline for more than 23 years. This was started in 1993 and was supposed to be a temporary plan to help the country get on its feet after the collapse of the Soviet Union, and the subsidies were due to expire in 2015. But in 2004, the Government extended them until 2030. However the situation is slowly changing. In December 2014, the Government doubled electricity tariff rates from TMT 1.2 (US$0.28) to TWT 2.5 (US$0.71) per 100 kWh.[32] In 2013, it was announced that the Turkmen Supreme Oversight Chamber started to monitor public consumption of free utilities, including electricity, natural gas and water. Unfortunately, there was no method for measuring use of utilities in the rural areas.[12,14] Therefore, authorities ordered the installation of natural gas meters.[14]

In order to raise awareness for the need to conserve natural resources, in 2013 Turkmenistan doubled the cost of natural gas above each person's monthly free quota of 50 cubic meters to US$7 (TMT 20) per 1,000 cubic meters. The price was still among the cheapest in Central Asia, thus it affected only those who exceed the free quota.[14] In addition, the Turkmen Government reduced the amount of free natural gas and electricity allotted. In September 2013, it reduced free electricity for each person from 35 kW to 25 kW per month. The Government also reduced the free natural gas allotment.[16] However this move did not decrease power consumption nationwide due to the still existing problems with metering.[14] Free utilities quotas have prompted customers to use natural resources wastefully.[14] Thus there were also problems with leaks because of the old gas/water pipes and electricity systems. In 2012 electricity losses were at 12 per cent.[29]

Turkmenistan aims to increase its power generation from approximately 19 TWh in 2011 to 27 TWh by 2020 and to 35.5 TWh by 2030.[23,24] In April 2013 the President approved The concept of development of electrical power branch of Turkmenistan for 2013-2020. According to the new plan the Government developed a policy of modernizing and expanding its electricity sector by increasing transmission infrastructure and constructing 14 natural gas-fired electric power plants between 2013 and 2020.[23,24,27,28] Two stages were planned for implementing the new concept, with each including construction of new power plants, power lines, complexes of modern transformer substations and distributive networks:

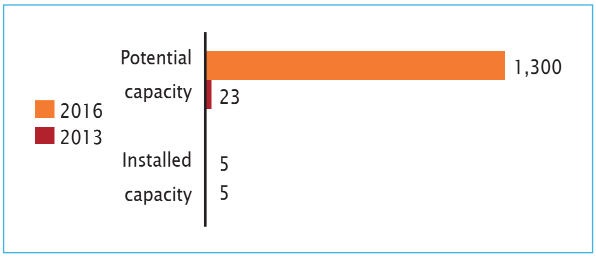
- Within the first stage between 2013 and 2016, it was planned to construct eight gas-turbine power plants in Akhalsky, Lebapsky and Maryysky district areas, reconstruct power plants in the cities of Sadie and Balkanabat, and also construct high-voltage power lines. This project could double the country's electricity generation.
- In the second stage between 2017 and 2020, the construction of six additional large power plants is to take place. The plants will carry out transitions at gas-turbine stations to the combined management; as well as continue on the construction of high-voltage power lines. In total the plan is expected to cost over US$5 billion.[28]

Small hydropower sector overview and potential

Installed capacity of SHP in Turkmenistan is 5 MW while the potential is estimated to be 1,300 MW indicating that only 0.4 per cent has been developed. The installed capacity has not changed between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016* (Figure 2).

FIGURE 2

Small hydropower capacities 2013-2016 in Turkmenistan (MW)



Sources: *WSHPDR 2013*,[25] UNDP[26]
Note: For 2016, technical potential for SHP is indicated.
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Turkmenistan has a small installed (operating) SHP capacity of approximately 5 MW.[12,26] The Hindu Kush, with three hydraulic turbines manufactured by the Austrian-Hungarian Hans Company, has a total installed capacity of 1.2 MW. Two other SHP plants, Kaushut-Bent of 0.6 MW and Kolkhoz-Bent of 3.2 MW are currently being upgraded by the European Bank for Reconstruction and Development (EBRD) as part of its Renewable Energy Initiative.[12] There are also many proposed SHP projects in Turkmenistan (Table 1).

In Turkmenistan, hydropower potential is mainly concentrated in the basins of the Murgab and Amu Darya rivers, with the highest potential on the Murgab and Tejen rivers and the Karakumy canal in the southern part of the country (Table 2).[12]

Turkmenistan signed a financial agreement under the Efficient Energy Programme for Central Asia (CASEP): Renewable Energy Sources – Programme of Energy

TABLE 1

Proposed programme for small hydropower development in Turkmenistan

Type of construction	Quantity	Potential capacity (MW)	Note	Region
Reconstruction and rehabilitation of existing hydro plants	3	4.7	Mostly former rural hydro plants of capacity between 0.8 and 2.7 MW	Lolontan region on Murgab River
Adding hydro plants to water management projects	6	52.3	Hydro plants of capacity between 2.6 and 15 MW	South Turkmenistan, Karakumy Canal, Murgab and Tenjen Rivers
Total	**9**	**57.0**		

Source: *WSHPDR 2013*[25]

Efficiency as part of technical cooperation with the European Commission.[18] A project was carried out between 2014 and 2015 under this programme, with the focus on supporting policy design and formulation towards the introduction of energy efficiency and renewable energy sources (EE and RES) at the national and regional levels. Introductory seminars have been carried out on EE policy planning and RES promotion (February 2015). The second component was the professional development of local partners in EE and RES policies and instruments. The third component was to ensure the implementation of sustainable pilot projects in the fields of EE and RES as well as to discuss and agree with the Turkmen Ministry of Economy and Development on the scope of CASEP support for EE/RES project developers.[30]

TABLE 2

Priority hydropower projects in Turkmenistan

Adding to water management projects	Potential installation capacity (MW)	Location
Hauznan reservoir HPP	11.7	Karakumy Canal, Mary Oblast
Kopetdag reservoir HPP	15.0	Karakumy Canal, Ashkhabad oblast
Saryyazin reservoir HPP	12.0	Murgab River, Mary Oblast
Tashkeprin HPP	7.0	Murgab River, Mary oblast

Source: *WSHPDR 2013*[25]
Note: HPP – hydropower plant

Renewable energy policy

Turkmenistan possesses a large renewable energy potential, including wind, solar, hydro, biomass and geothermal resources. However, the country has yet to develop a legal framework to regulate and promote renewable energy development. As of July 2014, the Government of Turkmenistan was working on a law on energy saving. The Law on Hydrocarbon Resources, signed in August 2008, encourages foreign investors to buy property in Turkmenistan.[9] The Renewable Energy Development Strategy plans to develop renewable energy frameworks.[7]

The annual energy potential of renewable energy sources in Turkmenistan is estimated at 110 billion tons of equivalent fuel a year. The country's climatic conditions provide an ideal setting for both solar and wind power research, as approximately 80 per cent of the country is covered by desert. Even though Turkmenistan is self-sufficient in electrical power generation, a number of localities such as the Caspian islands preclude stringing centralized electric power lines. Additionally, power shortages could be addressed by local renewable energy facilities.[15,17] A decree in 2014 by the country's President has called for the creation of the Solar Energy Institute within the Academy Sciences of Turkmenistan, which is intended to explore the potential of renewable energy sources, improve scientific and technological research and introduce relevant scientific innovations in the industries.[17,19,21] According to Turkmen experts, the priority areas include electricity, research and use of alternative energy sources—solar, wind, geothermal water, biogas, etc., and the use of clean and waste-free technologies.[15,20] Despite that, so far renewable energy development in the country have remained sluggish. Sitting on the world's fourth largest natural gas reserves and vast quantities of oil resources, there remains little motivation for Turkmenistan to pursue renewable energy alternatives.[17] However, there have been some minor RE projects carried out.[17]

Barriers to small hydropower development

Due to the existing free quotas on utilities, investment in renewable energy sources by private companies is not followed or promoted. Currently, due to the absence of a specific policy for the promotion of renewable energy, there is also no regulatory framework related to renewable energy. These conditions are not favourable for renewable energy projects entering the market.[12]

3.1.5 Uzbekistan

Eva Kremere, International Center on Small Hydro Power

Key facts

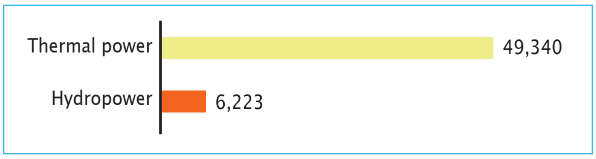
Population	30,492,800 [1]
Area	448,900 km[2]
Climate	Continental, with hot summers and cool winters. Summer temperatures range from 42-47°C on the plains to 25-30°C in the mountains. In winter temperatures are between –11°C in the north and 2-3°C in the south.[2] Of the land area, 20.4 per cent has semi-arid/steppe climate, 67.3 per cent has an arid/desert climate, 12.3 per cent has an alpine/highland climate.[3]
Topography	The country can be divided into three physiographical zones: the desert, steppe and semi-arid region that covers 60 per cent of the territory mainly in the centre and the west; valleys along the Amu Darya and Syr Darya rivers; and the mountainous region in the east consisting of Tien Shan and Gissaro-Alay mountain ranges.[2] The highest point is 4,643 metres at Khazret Sultan, while the lowest point is Sariqarnish Kuli, 12 metres below sea level.[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.[2]
General dissipation of rivers and other water sources	Most of the country lies between the Amu Darya and Syr Darya, which start in the mountains in the east of Uzbekistan and flow toward the Aral Sea. The country's water-flow patterns were greatly altered by numerous and extensive canal systems, such as the Amu-Bukhara canal, which were built during the Soviet era. There are also artificial lakes and reservoirs, many of which are fed by irrigation runoff.[4] The total length of the Amu Darya is 2,400 kilometres and its drainage basin totals 534,739 square kilometres, providing a mean annual water discharge of around 97.4 cubic kilometres. The Syr Darya River rises in two headstreams, the Naryn River and the Kara Darya, and flows for approximately 2,212 kilometres in the west and north-west of Uzbekistan and then into southern Kazakhstan to the Aral Sea. The Syr Darya drains an area of over 800,000 square kilometres. Its annual flow is at only 37 cubic kilometres per year.[5]

Electricity sector overview

The total installed generation capacity in 2014 was 12,992 MW.[37] In 2013 there were ten thermal power plants (TPP), including three combined heat power plants (CHPPs), with a total installed capacity of 10,660 MW, and eight hydropower cascade schemes with a total installed capacity of 1,850 MW.[22,28] Nine of these plants (439 MW of total capacity) belong to Uzsuvenergo (part of the Ministry of Agriculture and Water Resources), while the remaining are owned by the State Joint Stock Company Uzbekenergo.[38,22,34] The primary energy generation source in Uzbekistan is thermal (natural gas, coal, oil at 88.8 per cent), followed by hydropower (11.2 per cent) (Figure 1). Total electricity generation grew from 47,200 GWh/year in 2003 to 51,100 GWh/year in 2010 and 55,563 GWh in 2014.[22,34,37] Total electricity consumption in 2014 was 54,163 GWh. Total consumption is increasing on average by 3.1 per cent per year.[37] The industrial sector was the largest consumer of electricity, accounting for more than 45 per cent, while residential demand accounted for 24 per cent of total consumption, and has increased by 70 per cent between 2003 and 2010.[22] The peak demand on the main grid in 2013-2014 was 8,516 MW, and the average base load was 7,558 MW.[37]

FIGURE 1

Electricity generation by source in Uzbekistan (GWh)



Source: IJHD[37]

GDP growth of Uzbekistan in 2014 was 8.1 per cent while inflation was 6.1 per cent, therefore it resulted in a 0.2 per cent surplus and a positive trade balance of US$180 million.[20] The most important factor in ensuring sustainable economic growth was the reform of the banking system, resulting in the growth of aggregate capital of commercial banks which amounted to almost 25 per cent.[21]

In the past Uzbekistan was part of the Central Asia Integrated Power System (CAIPS). CAIPS was comprised of the interconnected power systems of the five Central Asian republics of the Soviet Union: Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan and Uzbekistan. The system was built during the Soviet era and designed for the trans-border supply of electricity across the entire region. While these strong interconnections between Uzbekistan and the region are still functional, the country's participation in electricity trade with its neighbours has been decreasing since 2000. Currently, Uzbekistan only exports a small amount of electricity to Afghanistan and receives some power from the Kyrgyz Republic. Nearly 40 per cent of the total installed generation capacity is past or close to the end of its operating life, and older thermal power units operate significantly less efficiently than newer units. Electricity losses in Uzbekistan are relatively high, estimated at 20 per cent of net generation.[22]

Most of the power generation, transmission and distribution assets in Uzbekistan are owned and operated by Uzbekenergo. It is composed of 53 subsidiary companies including 39 open joint-stock companies, 11 unitary enterprises, two societies with limited liability and company branch Energosotish. In 2015 privatization of enterprises affiliated with the company structure was launched and all of them, except two, have already been denationalized already.[17] As a result of the functional unbundling of the power sector, Uzbekenergo has at least one major subsidiary for each segment: generation, transmission and distribution. No power plants are privately owned.[37] The company's subsidiary, Energosotish, is the single buyer/the sole wholesale electricity purchaser and supplier.[14] Uzelectroset is the system operator providing dispatch, transmission and network services. Uzelectroset includes seven high-voltage transmission network affiliate operators. The distribution of electricity is carried out by 14 regional distribution companies.

Aging infrastructure and insufficient investments have increasingly resulted in power supply reliability problems.[9] Periodic failures of old transmission and distribution infrastructure and transmission capacity bottlenecks contribute to electricity supply disruptions. These problems are especially highlighted in the southern and western regions, with between two and six hours of blackouts a day during winter months when load is the highest. Rolling blackouts in other regions also occur occasionally during periods of peak demand.[23] As an alternative, people use diesel-fired backup generators, which produce electricity at a cost of roughly US$0.23/kWh. This is almost four times the average retail electricity tariff in Uzbekistan.[22]

The Government increased electricity tariffs by an average annual nominal rate of 12 per cent between 2004 and 2011, which allowed Uzbekenergo to cover its operating costs. However, the 2014 average tariff for household-end customers of US$0.053/kWh is not high enough to enable Uzbekenergo to provide US$5 billion, which is required to be invested in the energy sector by 2020.[19,22,37,16] Power transmission lines at all voltages extend over 235,000 km. All consumers are connected to the centralized power supply system.[12]

The Government of Uzbekistan recognizes its challenges. Therefore, among its high priority goals are reforms in the energy sector, with the aim to attract foreign investment funds in joint stock companies to carry out reconstruction, modernization, and further development of power generating facilities and power grids.[19] In 2011, Uzbekenergo developed The Complex of Concrete Measures on Realization of the Major Priorities of the Program of Social and Economic Development.[15] In accordance with the investment programme, 28 major investment projects were initiated to modernize and reconstruct existing facilities in 2014.[16,12,15,33] According to the Ministry of Economy, over the past five years the volume of lending to small businesses increased by nearly five times, so it is easier for small hydropower developers to receive financial support.[21]

The Government has initiated steps to support the development of the electricity sector:

- Securing the finances for 50 per cent of the critical medium-term investments required by 2015;
- A number of initiatives and projects have commenced, aiming to further develop and modernize the sector, ensure reliable energy supply and improve energy efficiency;
- End-user electricity tariffs were increased during 2004-2012, which enabled Uzbekenergo to cover operating costs;
- Experienced technical experts were contracted to ensure adequate operation and maintenance of assets;
- The functional unbundling of electricity generation, transmission, distribution and dispatch was completed.[22]

These reforms were undertaken for the purpose of improving operations and financial viability of the sector, as well as to increase the reliability of electricity supply. The Government recognizes the need to continue its work on the legal and regulatory framework, which will further improve the attractiveness of the sector for private investors.[22]

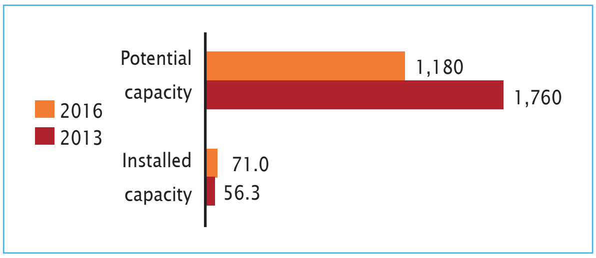
Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Uzbekistan is up to 10 MW. Installed capacity of SHP is approximately 71 MW while the potential is estimated to be at least 1,180 MW, indicating that 6 per cent has been developed (Figure 2). Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by 26 per cent while potential capacity has decreased by 33 per cent.

Despite the low share of hydro electricity production, approximately 11.2 per cent, Uzbekistan has a considerable potential for the development of SHP. The country has dozens of reservoirs, irrigation canals, and mountain rivers. Most of the water resources are suitable for at least 141 SHP plants, with total capacity of 1,180 MW and annual power generation of 4.6 TWh.[25] The potential for SHP was studied in 2006, as part of the overall hydro potential, though not in detail. The technicality feasible SHP potential was estimated to be 4 GWh/year (15 per cent of the total); and the economically feasible SHP potential 261.9 GWh/year for plants up to 10 MW.[37] Additionally, small-scale hydropower is particularly advantageous in meeting agricultural electricity demand in the country.[22]

FIGURE 2

Small hydropower capacities 2013-2016 in Uzbekistan (MW)



Sources: IJHD,[37] Gazeta.uz,[25] *WSHPDR 2013*[24]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Presidential Decree UP-4512 of 1 March 2013 (On Measures for Further Development of Alternative Energy Sources) has become an important impetus for the development of the sector.[30] Uzvodenergo has created the Programme for the Development of Hydropower in 2011-2015, and projected to implement nine projects worth US$260 million. The Programme planned to increase the generation capacity to 613 MW by the end of 2015, which would increase power generation from SHP plants by 1.115 TWh to 2.19 TWh.[34] This additional capacity is expected to help to save 685 million cubic meters of gas a year.[32] It also planned to build seven new SHP plants and reconstruct two existing SHP plants in Tashkent and Surkhandarya regions. Within the previous stage of the Programme for the Development of Hydropower, which was carried out between 1995 until 2010, five plants with a total capacity of 110 MW were put into operation, including the Urgut SHP plant of 1.5 MW.[38] According to the recently approved new stage of the programme for 2016-2020, the construction of four new hydropower plants with a combined capacity of 23.5 MW is expected. This will also include constructing three SHP plants of 8 MW, 2 MW and 2.5 MW, respectively and modernize 11 existing hydropower plants.[39]

The large hydropower plant and dam construction projects on the Amu Darya and Syr Darya rivers' upper reaches reduces the volume of water.[26,27] The Deputy Minister of Uzbekistan has confirmed the Government's interest to promote SHP development, as it does not change the water and environmental conditions of the rivers.[29] Currently, a number of SHP plants are under construction, with total installed capacity of 50 MW and total cost of US$150 million.[23,34] Also the construction of SHP plant Kamolot with a capacity of 8 MW on Chirchik-Bozsuyskiy channel was considered.[12] Feasibility studies of the Automated System of Commercial Accounting of Electrical Energy (ASCAEE) on cascades of Chirchik, Kadiriya, Tashkent and Nizne-Bozsy hydropower plants were carried out.[15]

Renewable energy policy

Due to abundant oil and gas resources in Uzbekistan, the Government has paid little attention to the development of renewable energy with the exception of hydropower and solar power. However, as cost for gas increases (due to rising gas export prices) and capital costs for renewable energy continue to follow a decreasing trend, renewable energy and other alternatives may start to look more attractive. The Government has indicated its commitment to increase the share of renewable energy in the generation mix.[35] Specifically, it is planning to construct 400 MW of SHP, 100 MW of solar and 100 MW of wind power. Moreover, in 2013 the World Bank prepared a project to provide financing and technical assistance for the development of small-scale renewable energy resources in the agricultural sector.[22] In particular, the Presidential Decree UP-4512, issued on 1 March 2013, and titled On Measures for Further Development of Alternative Energy Sources, has become an important impetus for the development of the sector.[30,16,31]

The country has a legal framework created in line with international standards aimed at the rational use of natural resources. Several state programmes and national action plans are also being implemented in this area. Uzbekistan has ratified major UN conventions and other international instruments in the field of environmental protection and sustainable development.[40] In 2013, the Ministry of Economy, the Academy of Sciences and Uzbekenergo, together with the concerned ministries and agencies, have been instructed to make a draft law on alternative sources of energy.[31]

Uzbekistan has a significant renewable energy resource potential that includes hydropower, solar and wind. Some estimates of the technical potential of renewable energy resources have been made (Table 1), but no comprehensive assessment of the economically and financially viable renewable energy potential has been conducted so far.[22]

As part of the investment prioritization, the Government should start planning to diversify the electricity generation mix to reduce near complete dependence on natural gas and use it for higher value exports, improve supply reliability and reduce vulnerability of the power sector to climate change. Diversification of the generation mix will also enable the Government to use revenues from increased gas exports to finance much needed power sector capital investments.[22]

TABLE 1

Estimated technical potential for renewable energy resources (electricity production)

Resource	Technical potential (GWh/ year)	Utilized potential (GWh/ year)
Solar energy	2,058,000	—
Large and medium hydropower	20,934	1,650
Small hydropower	5,931	200
Wind	4,652	—
Biomass	1,496	—
Total 2014 electricity generation	**55,563**	—

Source: World Bank[22]
Note: Data on potential is from 2011.

Barriers to small hydropower development

Uzbekistan has a great potential for improving energy efficiency of the supply and consumption of electricity.[36] Key challenges for the development of SHP are:

- Aging energy infrastructure;
- Lack of financing and investment in the energy sector;
- Low electricity prices;
- Lack of clear support mechanisms for SHP development;
- Lack of feasibility studies and available data.

3.2 Eastern Asia

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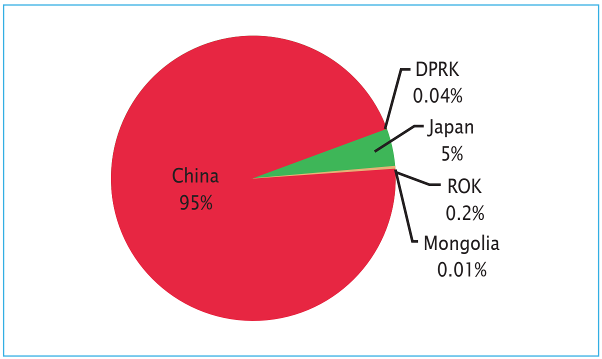
Introduction to the region

Eastern Asia comprises seven countries and territories: China, Hong Kong Special Administrative Region, Macao Special Administrative Region, Democratic People's Republic of Korea (DPRK), Japan, Mongolia and the Republic of Korea. The present report looks at the use of small hydropower (SHP) in China, DPRK, Japan, Mongolia and the Republic of Korea. An overview of countries of Eastern Asia is given in Table 1.

FIGURE 1

Share of regional SHP by country



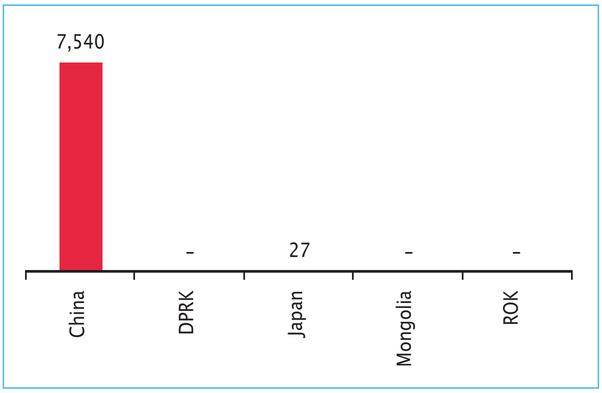
Source: *WSHPDR 2016*[2]
Note: SHP in China is classified as <50 MW.

The region varies significantly in terms of resource endowments. China has the largest exploitable hydropower potential in the world as well as considerable coal, oil, gas and wind resources, which are, however, mostly located far from the major cities. Japan and the Republic of Korea have limited coal, gas and oil reserves but significant wind potential, whereas their hydropower potential is already largely tapped. Mongolia has significant coal, wind and solar reserves as well as hydropower potential. The DPR of Korea has some remaining untapped potential, to include SHP, as well as abundant coal deposits. However, the country has no significant oil or gas production.[3]

Energy policies in the region are largely defined by the countries' energy concerns associated with their rapid economic growth and increasing population, and thus escalating energy demand and consumption. Although the region possesses significant resources that could contribute towards its energy needs, most reserves are located in distant areas far from densely populated centres. Bringing them to the market would require additional investments in infrastructure as well as environmental, political, economic and technical considerations, especially in case of cross-border projects.

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for Eastern Asia



Sources: *WSHPDR 2013*,[1] *WSHPDR 2016*[2]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The economic growth in the region has also had negative consequences for the environment, including ever-growing emissions of greenhouse gas and other

TABLE 1

Overview of countries in Eastern Asia (+/– % change from 2013)

Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
China	1,364 (+2%)	45 (–8pp)	100 (+0.6pp)	1,370,180 (+42%)	5,604,500 (+49%)	304,860 (+42%)	1,060,100 (+60%)
DPRK	25 (+3%)	39.3 (–0.7pp)	26 (0pp)	10,000 (-)	19,524 (–13%)	5,474 (+15%)	13,702 (+5%)
Japan	127 (–0.4%)	6.9 (–26pp)	100 (0pp)	289,171 (+3%)	1,090,609 (-)	48,932 (-)	84,885 (+14%)
Mongolia	3.06 (+11%)	27.3 (–11pp)	90 (+23pp)	1,178 (-)	5,392 (-)	28 (0%)	66 (-)
ROK	51 (+4%)	17.5 (+0.5pp)	100 (0pp)	96,830 (-)	541,996 (-)	1,644 (+7%)	8,394 (-)
Total	**1,570.06 (+2%)**	—	—	**1,767,359**	**7,262,021**	**360,938**	**1,167,147 (-)**

Sources: Various[1,2,4,5,6]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

air pollutants, which produce a significant effect on air quality. Trying to mitigate these environmental problems, the governments encourage development of renewable energies. Finally, the region heavily relies on nuclear power, and as a result deals with a range of related issues, including environmental and health risks.[3]

Small hydropower definition

The definition of SHP varies across the region (Table 2). Japan and Mongolia assume plants with installed capacity of below 10 MW as small, whereas in China SHP refers to capacities of up to 50 MW. The Democratic People's Republic of Korea and the Republic of Korea have no official definition of SHP. Until 2005, the Republic of Korea classified hydropower units with a capacity up to 10 MW as SHP. However, presently, hydropower plants are no longer classified according to their installed capacity. Furthermore, the countries consider every type of generator that generates electricity based on water flow as hydropower. For the purpose of this report, the definition of up to 10 MW for SHP will be used when regarding the DPRK and the Republic of Korea.

TABLE 2

Classification of small hydropower in Eastern Asia

Country	Small (MW)
China	Up to 50
DPRK	—
Japan	Up to 10
Mongolia	Up to 10
Republic of Korea	—

Sources: *WSHPDR 2013*,[1] *WSHPDR 2016*[2]

Regional small hydropower overview and renewable energy policy

The installed capacity of SHP in Eastern Asia is around 77 GW (up to 50 MW), which accounts for approximately 4 per cent of the region's total installed capacity and 55 per cent of the region's discovered SHP potential (Table 3).

China is the regional leader in terms of both installed and potential SHP capacity (up to 50 MW). Due to the support of the Government and the technological maturity of the domestic hydropower sector, SHP has developed rapidly in the country, with 47,073 SHP plants widely distributed across the country as of 2014. The total installed capacity of SHP in China is 73.2 GW, reaching 57 per cent of its SHP potential. According to the national programme of SHP development, by 2030, it is expected to exceed 93 GW of total installed SHP capacity or 77.5 per cent of the potential; and by 2050, it is expected to reach 100 GW or 83 per cent of the potential. Before 1990, SHP projects were predominantly funded by the central or the local governments. However, since the late 1990s due to the country's escalating energy demand, the investment system has undergone reforms, which allowed private investors to access the market.

The Democratic People's Republic of Korea has an installed capacity of 33 MW from SHP. The country's potential for SHP development is speculated to be significant due to its numerous rivers. However, no comprehensive data is available. There were three planned SHP projects with a combined capacity of 19.2 MW reported in 2013; therefore it can be concluded that the country has at least 52.2 MW of SHP potential. However, the actual potential could be significantly higher. The Government has encouraged the development of micro hydropower as part of the national programme on rural energy development. In general, the Government's energy policy focuses on the development of non-fossil fuel energy sources and aims to solve the issue of ageing infrastructure and the transmission and distribution network, as well as to improve rural energy supply.

TABLE 3

Small hydropower in Eastern Asia (+/– % change from 2013)

Country	Potential capacity (MW)	Installed capacity (MW)
China (< 50 MW)	128,000 (0%)	73,220 (+12%)
DPRK (< 10 MW)	52.2 (-)	33 (-)
Japan (< 10 MW)	10,270 (+0.03%)	3,545 (+0.8%)
Mongolia (< 10 MW)	13 (-57%)	5 (0%)
Republic of Korea (< 10 MW)	1,500 (0%)	159 (-)
Total	**139,835 (+0.03%)**	**76,962 (-)**

Sources: *WSHPDR 2013*,[1] *WSHPDR 2016*[2]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Japan has a total SHP installed capacity of 3,530 MW, which is about 34 per cent of its potential. The country has a long history of hydropower development. For a period of time SHP was considered inefficient, and thus was not developed. In the 2000s, SHP again attracted attention as a solution to climate change and reduction of greenhouse gas emissions, and is now gaining new positions as a natural energy resource to be developed.

Mongolia has eleven SHP plants with capacities of up to 2 MW. Their combined installed capacity is 5 MW. As opposed to the two large hydropower plants, SHP plants only serve isolated areas of the country and operate in summer. Hydropower development in the country is mainly focused on large hydropower as it is seen as a solution towards a better national energy security and energy independence. The Government aims to increase the use of renewable energy sources, particularly in remote areas, as well as to perform research and development in the field of renewable energy. However, there are no known plans for further development of SHP.

The Republic of Korea has 159 MW of installed SHP capacity with plants located on 108 sites nationwide.

The technical potential of SHP from rivers and other water-related facilities (such as sewage treatment plants, water treatment systems, irrigation reservoirs, multi-purpose dams and irrigation dams) is estimated at 1,500 MW, of which 660 MW is economically feasible. Since the two oil crises in the 1970s, the Government has actively encouraged the development of renewable energy sources, including SHP. The goal is to replace 11 per cent of the primary energy supply with new and renewable energy supply by 2035. There is a range of financial supports for the new and renewable energy industry. As of 2014, the Government provided a total of KRW 100 billion (about US$95 million) of subsidies to SHP.

Three countries of the region introduced feed-in-tariffs (FIT). In Japan FITs were introduced in 2012; they are set for each renewable energy category, and are revised each year based on a degree of circulation and market conditions. Mongolia created a FIT system applicable to renewable energy generators in 2007. The tariffs are set by the Energy Regulatory Authority (ERA) within set limits for grid-connected and off-grid generators according to energy type. China has FITs for solar, hydro, wind and biomass. However, there is no unified FIT for SHP; each province establishes the benchmark price for SHP projects based on the average purchasing price of the provincial grid company.[7]

Barriers to small hydropower development

Countries of the region face different difficulties that might hinder SHP development.

China experiences technical and environmental difficulties as well as constraints associated with land compensation, labour cost and resettlement. For some rivers in the country, the environment has been damaged due to violations of land and water conservation rules by hydropower developers; some rivers were overexploited causing dehydrated sections, which impacts the drinking water downstream and the ecology of the whole river.

For the Democratic People's Republic of Korea, the lack of financial resources is the main barrier to developing its SHP potential. The country also lacks locally produced hydropower generation equipment and automation.

Due to a 50-year break in SHP development, Japan lacks skilled personnel and technology, which leads to insufficient capacity in site assessment, planning and design. Other constraints include limited profitability of SHP projects, lack of sufficient facilities and conflicts over water ownership.

The development of SHP in Mongolia is, first of all, hindered by the lack of interest in small-scale projects on the part of the Government and its focus on large hydropower instead. Developers can also experience difficulties due to the ambiguity of the licensing process as well as the lack of financial resources.

For the Republic of Korea, the major barriers are, firstly, its topography, which does not allow high head turbine installation, secondly, low level of development of the local SHP industry and, finally, the focus of the Government on photovoltaic and wind energy, which can lead to a reduction of financial support for SHP.

3.2.1 China

Heng Liu, Nanjing Hydraulic Research Institute, and Xianlai Wang, International Center on Small Hydro Power

Key facts

Population	1,364,270,000[1]
Area	9.6 million km²
Climate	Extremely diverse; ranging from tropical in the southern parts to subarctic in the north. Minimum temperatures between December and February (winter) range between -27°C in northern Manchuria, -1°C in the North China Plain and southern Manchuria, 4°C along the middle and lower valleys of the Yangtze, and 16°C farther south. Summer temperatures in southern and central China have a mean of approximately 27°C in July. Northern China has a shorter hot period and the nights are much cooler.[2]
Topography	China is roughly divided into two parts: lowlands in the east, which is about 20 per cent of the total territory; and mountains and plateaus in the west, which constitutes the remaining portion of the country. The highest mountain, and also tallest in the world, is Mount Everest, situated in the Himalayas in the Tibet Autonomous Region; its peak is 8,848 metres above sea level. The lowest point in China is Ayding Lake, located in Xinjiang Uyghur Autonomous Region; it is 154 metres below sea level.[2]
Rain pattern	Given the country's vastness, many degrees of latitude, and complex terrain, it has a variety of precipitation levels including continental monsoon areas. Annual mean range is high 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.
General dissipation of rivers and other water sources	There over 1,500 rivers each with a drainage area of over 1,000 km². The great rivers of China generally flow from west to east to discharge into the Pacific. The largest river in China, the Yangtze, is approximately 5,525 km in length and drains an area of approximately 1.8 million km². The main river in northern China, and the second largest in the country, is the Yellow River which is approximately 4,671 km. The valley of the Yellow River covers an area of 1.5 million km².[2]

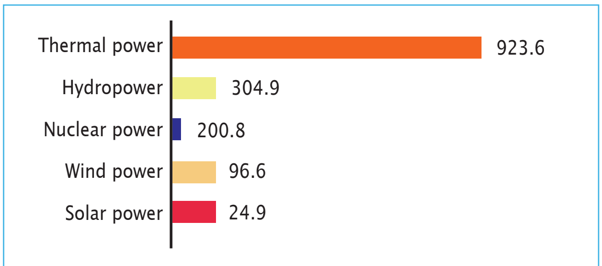
Electricity sector overview

By the end of 2014, the total installed capacity in China had reached 1,370.18 GW. This consisted of 923.63 GW of thermal power, 304.86 GW of hydropower, 96.57 GW of wind power, 24.86 GW of grid-connected solar power and 200.8 GW of nuclear power (Figure 1).[3] China has the largest installed capacity in the world for both hydropower and wind power.[4]

In 2014, the total electricity generation was 5,604.5 TWh. Hydropower generation, at 1,060.1 TWh,[3] accounts for 28.7 per cent of the total generation.

FIGURE 1

Installed electricity capacity by source in China (GW)



Source: China Electricity Council[3]

China has the largest installed hydropower capacity in the world. In 2014, its newly installed hydropower capacity exceeded 20 GW, fulfilling the target set in the 12th Five-Year Plan one-and-a-half years ahead of schedule. The Xiluodu Station, Xiangjiaba Station and Nuozhadu Station, which are the second, third and fourth largest hydropower projects, respectively, in China, were commissioned in 2014.[6] The unit capacities of the Xiluodu Station and Xiangjiaba Station are 770 MW and 812 MW, respectively.

By the end of 2012, there were 2.73 million people, approximately 0.2 per cent of China's population, mainly in remote regions such as Xinjiang, Sichuan, Qinghai, Gansu, Inner Mongolia and Tibet, without access to electricity. In 2013, the National Energy Bureau launched the Three-Year Action Plan, which aimed to resolve the electricity access problem nationwide (2013-2015). Its time frame stated that by the end of 2015, the electricity access problem should have been resolved, thus bringing the national electrification rate up to 100 per cent. This meant connecting 1.54 million people to the grid and connecting the remaining 1.19 million to isolated solar generation. By December 2015, China had achieved this action plan.[7]

The Chinese electricity sector was reformed in 2002. The vertically-integrated State Power Corporation of China was divided into five separate generation companies, which accounted for an estimated 36 per cent of the country's generating capacity: China Huaneng Corporation, China Huadian Corporation, China Power Investment Corporation, China Guodian Corporation and China Datang Corporation. These companies are partially privatized with listings on one or more international stock exchanges. The remaining capacity is owned by local government corporations, quasi-private companies and private companies, making up slightly over half of the total capacity. This includes the county's two grid-operating companies, the State Grid Corporation and the South China Grid Corporation.[8]

The national grid is divided into six grids. The Northeast China Grid, North China Grid, East China Grid, Central China Grid and Northwest China Grid are managed by the State Grid Corporation, while the South 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 re-sell to customers and distribution companies in their service areas.[8]

Regulation of the power sector in China is divided between the National Development and Reform Commission (NDRC) and the State Electricity Regulatory Commission (SERC). The NDRC's responsibilities include investment, pricing and power plant approvals, while the SERC is responsible for the design, oversight of generation markets and implementing power sector reforms. The SERC also gives input to the NDRC on pricing and market reforms.[8]

The country's grid is dominated by fossil-fuel generation. However, great efforts have been made to decrease the dependency of fossil fuels while continuing to satisfy demand. As a result, clean energy has been accelerated in the last few years. The progression has been so effective that in 2013, fossil-fuel installed capacity dropped below 70 per cent of the total, accounting for 69.4 per cent. In 2014 it dropped further, with fossil-fuel installed capacity accounting for 67.32 per cent; a decrease of almost 3 per cent.[9]

In July 2012, China adopted a Multistep Electricity Price Mechanism, which increased the consumer tariff in multiple steps as consumption level rose, while peak and valley time tariffs were also implemented. However, according to the China Price Information Network, consumer tariffs vary between the provinces, with the average national consumer tariff at approximately CNY 0.4/kWh to CNY 0.6/kWh (US$0.06-0.09), and the average industrial tariff at approximately CNY 0.7/kWh to CNY 0.9/kWh (US$0.11-0.14)[10]

Small hydropower sector overview and potential

In China, small hydropower (SHP) refers to capacities of up to 50 MW (Table 1). In 2014, there was a total of 73.22 GW installed capacity from SHP and a total potential of approximately 128 GW, indicating that approximately 57.2 per cent had been developed. Since 2014, there was an installed capacity of 39.8 GW, with an estimated total potential of 63.5 GW for plants up to 10 MW, indicating that approximately 63 per cent had been developed.[11]

TABLE 1

Classification of small hydropower in China

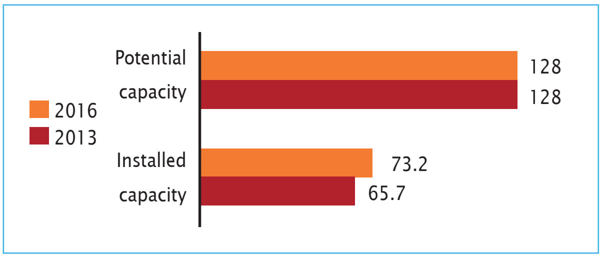
Definition	Installed capacity (MW)
Small	≤ 50
Mini	≤ 2
Micro	≤ 0.1

Source: *WSHPDR 2013*[12]

In comparison to data from the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, the total potential for plants up to 50 MW has remained the same, while installed capacity has increased by approximately 11.5 per cent (Figure 2). For plants up to 10 MW, the total potential has remained the same while installed capacity has increased by approximately 7.9 per cent (Figure 3).[12]

FIGURE 2

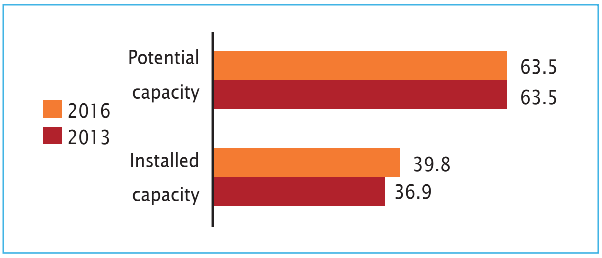
Small hydropower capacities up to 50 MW in China 2013-2016 (GW)



Sources: China Ministry of Water Resources,[7] *WSHPDR 2013*[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

FIGURE 3

Small hydropower capacities up to 10 MW in China 2013-2016 (GW)



Sources: China Ministry of Water Resources,[7] *WSHPDR 2013*[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

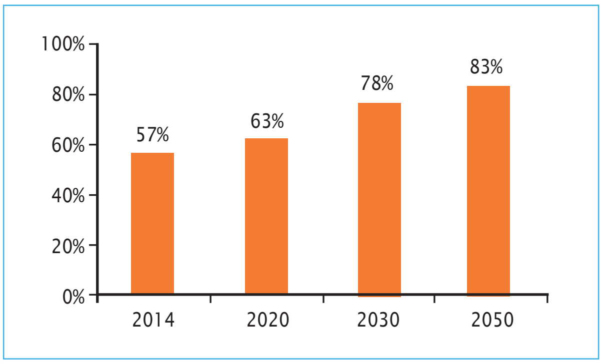
With a technologically mature hydropower sector, and over 1,500 rivers with a drainage area of over 1,000 km^2 each, SHP is an abundant resource in China. In 2014 there were approximately 47,073 SHP plants accounting for

24.3 per cent of the total installed hydropower capacity. Annual generation was 22.81 TWh or 4.11 per cent of the total electricity generation of the country.[12] Plants are widely distributed across more than 1,700 counties and in over 30 provinces, regions and municipalities. In the western regions, however, and mainly among remote mountainous areas where minority groups reside over vast areas, sparse populations and decentralized energy demand, the state grid is not connected due to the lack of long-distance power-supply technology. Therefore SHP is estimated to provide access to electricity to more than 300 million people, in one third of the western counties and half of all the territories in China.

The country's SHP potential of 120 GW is the highest in the world, with 57.2 per cent developed by 2014. According to the 12th Five-Year Plan and the Small Hydropower Development Scheme of 2020, published by the Ministry of Water Resources, installed capacity will amount to 75 GW or 62 per cent of total potential developed by 2020. By 2030, it is expected to exceed 93 GW or 77.5 per cent of total potential developed and, by 2050, it is expected to reach 100 GW or 83 per cent of total potential developed (Figure 4).[13]

FIGURE 4

Projected development of small hydropower potential in China 2014-2050 (%)



Source: China Reform Daily[13]

In the past few decades, the development, investment and asset management of Chinese SHP has changed. Before 1990, Chinese SHP plants were mainly funded by the central and local governments. However, after the late 1990s, due to a rapid development of the Chinese economy, the gap between power supply and demand rose dramatically, causing power supply shortages in most provinces. During this period, the Chinese investment system started to be reformed through a combination of government guidance and market mechanisms. A variety of economic entities were encouraged to invest in and develop SHP with the aim of narrowing the gap between power supply and demand, and the shortfall in government funds.

In addition to investments made by the Chinese Government, many private investors have become increasingly involved in hydropower development. Over a 10-year period beginning in 1990, SHP investment experienced a gradual transition away from the central and local g, shifting towards corporate enterprises (including foreign ones), with joint ventures and private hydropower plants accounting for an increasing proportion of the newly installed capacity. Moreover, a set of technical standard systems, including an SHP programme encompassing design, construction, installation, experiment, operation and equipment manufacture, was set up to provide technical support and service for SHP development.[14]

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. The projects where the local governments are the investors are more focused on social and public welfare while the projects where the community or private entities are the investors are more profit-oriented.

There are three important reasons SHP's rapid development:[15]

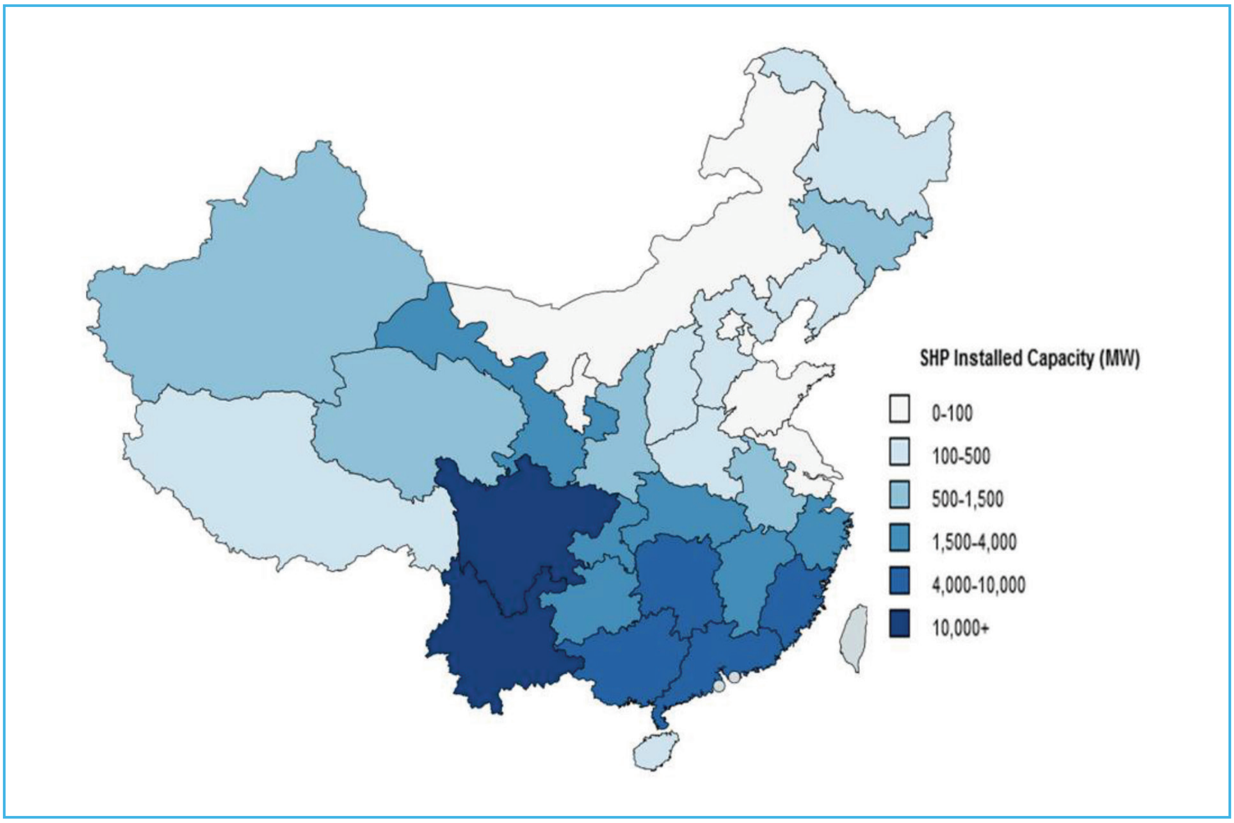
- The Government's implementation of favourable SHP policies, including aspects of ownership, taxes, and also incentives to attract private investments.
- The domestic supply of hydropower equipment reduced project-developing costs, which allowed for affordable hydropower systems. In the 1970s, the annual demand for hydropower equipment was approximately 200-300 MW, while the production capacity was only 100 MW. Now the annual production capacity has increased to 4,500-5,000 MW. Additionally, the technology of design and manufacture for large hydropower units are close to global standards, with added advantages in production, quality and price for medium and small hydropower equipment. This not only satisfies the domestic demand but it also engages the international market, exporting many systems abroad.
- SHP has more advantages than large hydropower. It is sustainable, requires simple engineering, short construction periods, small investments and with a lower impact on submerged losses, immigration and the environment (both ecologically and globally). Moreover, most of the SHP plants have their own local grid and supply areas, which are connectable to the national grid, allowing the local grid and national grid to mutually complement each other when necessary.

Renewable energy policy

The Energy Development Strategy Action Plan 2014-2020, launched on 19 November 2014 by the State Council, aims to: (a) increase non-fossil fuels contribution to the total energy consumption to 15 per cent; (b) reduce coal's contribution to less than 62 per cent; and (c) have natural gas account for more than 10 per cent by 2020.[16] Specifically, there is the need to optimise the industrial and energy structures, adjust the fossil fuel energy structure,

FIGURE 5

SHP installed capacity by province (MW)



Source: China Electricity Council[3]

further develop hydropower, safely develop nuclear power, aggressively develop wind power, promote multi-purpose utilisation of solar energy and develop biomass energy along with other renewable energy sources.

The country's hydropower development target is to increase installed capacity, including SHP, to 350 GW by 2020, with an additional 70 GW by 2030 and another 70 GW by 2050. This will bring the total hydropower installed capacity to 660 GW, more than twice the current capacity and 80 per cent of the potential developed.[17]

China's target for wind energy development is 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 by 2050.[18] The national solar energy utilization target is for solar energy to replace 150 million tons, 310 million tons and 860 million tons of coal, equivalent to the consumption of fossil fuel and generating approximately 150 GWh, 510 GWh and 2,100 GWh by 2020, 2030 and 2050, respectively.[19]

Legislation on small hydropower

The Chinese Government has passed a series of policies to support and encourage local governments and local people to develop nearby rich 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. Value-Added Tax (VAT) for SHP has, since 1994, stood at 6 per cent, making it much more favourable than the 17 per cent levied on large hydropower stations. The Bureau of Hydropower and Rural Electrification Development is also working to promulgate a specialized regulation on rural hydropower development and management.

The Government continues to support the SHP sector as part of its 12th Five Year Plan (2011-2015). The first objective is completion of the National Planning of New Rural Electrification project, which intends to invest CNY 43.52 billion (approximately US$7 billion) to build SHP plants in 300 new rural electrification counties, with a planned newly installed capacity of 5,156 MW. This is expected to provide an annual energy output of 19.16 TWh.[20]

The second objective is the wider implementation of the tasks covered by the Hydropower for Fossil Fuel Power Plan 2009-2015, which aims to solve the fuel concerns of 6.78 million rural residents. It also aims to protect a forest area of approximately 1.6 million hectares by substituting the local heating practices, which uses firewood, through the construction of 1,022 SHP stations with a combined installed capacity of 1,705.6 MW.[21]

The third objective is to carry out SHP efficiency (rural) and capacity expansion projects. A total investment of CNY 3.75 billion (approximately US$600 million) has been planned for the refurbishment of 620 rural hydropower stations with a total capacity of 880 MW within a two-year period (2011-2012). The implementation will consolidate, recover and renew some 1.1 GW of generation capacity.[22]

The 13th Five Year Plan (2016-2020) has an explicit target to increase capacity by 10 GW. This consists of: 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.[23]

There is no unified feed-in tariff for SHP in China. Each province has the right to establish the benchmark price for SHP projects within the province, based on the average purchasing price of the provincial grid company as well as consideration for the supply and demand trends of the electricity market and SHP development costs. The average feed-in tariff in 2014 for SHP was 0.317 yuan/kWh (US$0.05) and 0.256 yuan/kWh (US$0.04), respectively, for connecting to national grids and local grids. This varies between provinces.[11]

Barriers to small hydropower development

Despite the favourable conditions for developing SHP, there are still a number of challenges that affect the development of SHP in China. First, it is becoming increasingly difficult to develop the remaining SHP potential due to the development disparities between regions. For example, though the SHP development has reached 57 per cent nationwide, that number is actually much higher in some eastern provinces, with some areas reaching a development rate of 80 per cent. Aside from the technical difficulties, the constraints caused by land compensation, labour cost, eco-environment and resettlement issues are more serious.

Second, for some rivers, the environment has been damaged due to projects that did not strictly carry out measures for soil and water conservation and environmental protection. Some rivers were overexploited, causing dehydrated sections, which affected the drinking water downstream and the ecology of the whole river.

Third, the hydropower resources allocation in some river basins is unreasonable owing to the limitation of technology, funds and layout in the past. Some medium and small rivers are lacking a combined dispatching system.

Fourth, some of the existing plants are already ageing and in a state of disrepair, and though the 12th Five Year Plan has refurbished 4,400 plants, there are still a large number of plants not included in the plan.[24]

3.2.2 Democratic People's Republic of Korea

Tom Rennell, International Center on Small Hydro Power (ICSHP)

Key facts

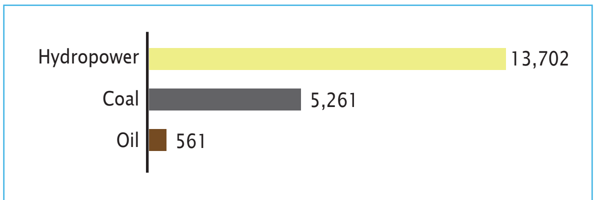
Population	25,000,000[1]
Area	120,538 km^2 [2]
Climate	The Democratic People's Republic of Korea has a continental climate with four distinct seasons. Winter months between December and February bring very cold and clear weather with daily average high and low temperatures in the capital, Pyongyang, in January of -3°C and -13°C respectively. Summer months between June and August tend to be hot and humid with monthly average high and low temperatures for Pyongyang in August of 29°C and 20°C, respectively.[3]
Topography	Mountains cover 80 per cent of the country, especially in the northern and eastern coastline; with wide plains in the coastal regions in the west. The highest point is Paektu-san at 2,744 metres.[4]
Rain pattern	Average annual precipitation is between 1,000 mm and 1,200 mm. Summer months are the wettest with an average of approximately 60 per cent of all precipitation occurring between June and September.[3] An abnormally long period of drought has been reported recently, which has had a severe impact on water supplies.
General dissipation of rivers and other water sources	The mountain ranges in the north and east form the watershed for most of the country's rivers, which run in a westerly direction into the Yellow Sea (Korea Bay). The longest is the Yalu River at 790 km. The Tumen River, one of the few major rivers to flow into the Sea of Japan, is the second longest at 521 km.[4]

Electricity sector overview

Total installed capacity is estimated to be between 9,500 MW and 10,000 MW, with the energy sources being coal or hydropower.[5,6] Annual generation in 2013 was reported to be 19,524 GWh, with approximately 70 per cent generated from hydropower plants, 27 per cent from coal based power plants and 3 per cent from oil-based power plants (Figure 1).[7]

FIGURE 1

Electricity generation by source in Democratic People's Republic of Korea (GWh)



Source: IEA[7]

In 2012 the national electrification rate was estimated to be 26 per cent, with power shortages taking place sporadically.[8] All energy infrastructures are state-owned. However, much of the infrastructure is outdated, poorly maintained or based on obsolete technology. Key government ministries include the Ministry of Power Industry, the Ministry of Atomic Energy and the Ministry of Coal Industry.

Electricity shortages, blackouts and rationing are common. Severe flooding in the past rendered some hydropower plants inoperable. More recently, however, a severe drought, reportedly the worst in 100 years, beginning in 2014 and continuing into 2015, has had a hugely negative impact on the country's hydropower plants, reducing their output by up to 10 per cent in 2014. Rainfall in 2014 was 40-60 per cent below 2013 levels, the lowest in 30 years.[10] This also has negatively impacted the coal industry, with electric trains and mining equipment operating below optimum efficiency due to power shortages.[9] During his 2015 New Year Address, Supreme Leader Kim Jong-Un acknowledged the DPRK's energy deficiency, saying the country should be "waging a campaign to economize on electricity to the maximum, while taking realistic measures to resolve the electricity problem in a prospective way."[10]

The Government has also announced its aim of increasing power levels by 30 per cent to 50 per cent compared with 2014 levels, with two key hydropower projects due for completion by the end of 2015: the Mount Paektu Songun Youth Power Station Units No. 1 and No. 2 near the Chinese border, and four units of Huicho Power Station along the Chongchon River.[11]

A Sustainable Rural Energy Development Programme was operating from August 2006 until March 2007, when United Nations Development Programme operations were suspended. In January 2011 the project resumed activities with the aim 'to strengthen the sustainable and efficient use of conventional energy and to improve accessibility of alternative energy sources for local communities and households'. This includes renewable energy pilot demonstration schemes.[12]

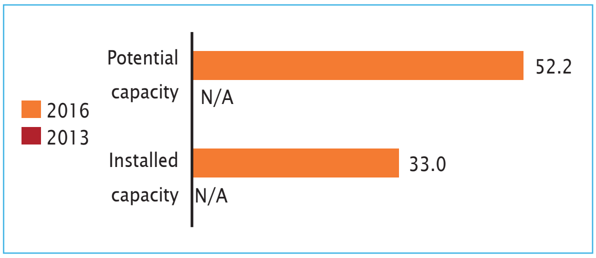
Small hydropower sector overview and potential

Information on the small hydropower (SHP) situation is not comprehensively known. The country has no official definition of SHP. However, this report is based upon a definition of hydropower plants of below 10 MW capacity. SHP installed capacity is estimated at 33 MW, though there is no data on SHP potential in the country. Nonetheless three SHP projects with a combined capacity of 19.2 MW were reportedly planned in 2013 indicating there is a total potential of, at least, 52.2 MW (Figure 2).[5,13,14] In the *World Small Hydropower Development Report* (*WSHPDR*) *2013* there was no available data on either the installed or potential capacity. Total hydropower capacity is estimated at between 5,474 MW and 5,768 MW meaning SHP represents less than 1 per cent of the total hydropower power capacity.[6,13]

The three planned SHP plants announced in 2013 are detailed in Table 1. Actual potential in the Democratic People's Republic of Korea is likely to be much higher than 52.2 MW. However, there is no available data for public use. Many rivers, reservoirs, irrigation canal networks and tidal dykes along the west coast are favourable for large-, medium- and small-sized hydropower development. The sites suitable for SHP vary in heads. Almost 80 per cent of the estimated sites have a head lower than 15 metres, and among those 50 per cent have a head of 5 metres. However, the total SHP potential was not clearly stated in the available documents.[14]

FIGURE 2

Small hydropower capacities 2013-2016 in Democratic People's Republic of Korea (MW)



Sources: IJHD,[6] IRENA,[13] Jin and Chol[14]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. Potential figures are based upon planned construction.

Micro hydropower development has been encouraged for rural areas as part of the Sustainable Rural Energy Development Programme. One example is a 600 kW plant at Myongchon Farm in Jangyon County which was supplied to a local community with residents taking part of construction.[15]

TABLE 1

Planned small hydropower plants in the Democratic People's Republic of Korea (MW)

Basin	Number	Capacity (MW)
Daedong No. 5	4	10
Dokji	4	3.2
Jangia	3	6.0
Total	**11**	**19.2**

Sources: IJHD,[6] Jin and Chol[13]

Renewable energy policy

The policy orientation of the Government is towards non-fossil fuel options, solving the issue of ageing infrastructure and of the transmission and distribution network, as well as improving rural energy supply.[16]

In fact, since the Fukushima nuclear incident in March 2011, the Democratic People's Republic of Korea's state media have reported widely on renewable energy development, with leader Kim Jong Il inspecting a newly constructed experimental solar water heating facility in Pyongyang, and stating his approval to 'aggressively develop and utilise renewable energy sources, such as solar heating'.[17] There are recent indications of the nation's desire to increase bi-lateral agreements and technology transfers within the renewable energy sector.[18]

According to Korean Central News Agency, the Democratic People's Republic of Korea has, in addition, revised its environmental protection law in late 2011 to promote the development and use of renewable energy sources.[17]

Barriers to small hydropower development

Financial challenges are the main barriers to developing the SHP potential, as is a lack of available data. Remaining problems include the lack of generation equipment including turbines and power systems, as well as automation.

3.2.3 Japan

Tokihiko Fujimoto, Shizuoka University and Kyushu University

Key facts

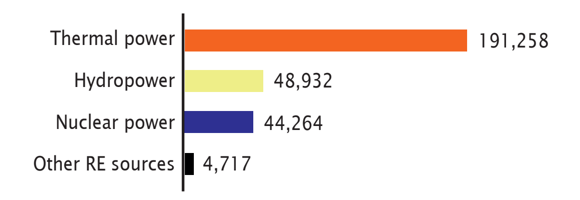
Population	126,896,000[1]
Area	377,962 km[2]
Climate	The climate in Japan varies from north to south. While the south experiences a more tropical climate, the north is much cooler. The annual average temperature ranges from 7.3°C in the most northern city, Wakkanai, Hokkaido, to 23.3°C in the most southern city, Naha, Okinawa. The capital city, Tokyo, experiences an average temperature of 17.3°C.[17]
Topography	The land consists of 6,852 islands, all of which are in a volcanic zone. 67 per cent is a mountainous area, with the highest point being Mount Fuji, at 3,776 metres. The coastline is 29,751 km long. This topography produces a rich space all over the land with plentiful river flow that streams from mountains to sea through alluvial fans and plains.[17]
Rain pattern	The country experiences the East Asian Monsoon, allowing for an annual average of precipitation of 1,046 mm in Wakkanai, 1,614 mm in Tokyo, and 2,071 mm in Naha (as recorded in 2013).[17]
General dissipation of rivers and other water sources	The rivers in Japan are short with rapid flows and steep gradients producing waterfalls dispersed throughout the mountainous landscape. The three longest rivers are Shinano, Tone and Ishikhari Rivers.[17]

Electricity sector overview

According to the Statistics Bureau of Japan, the country's total installed electrical capacity is 289,171 MW. The total capacity is composed of thermal plants at 191,258 MW; hydro, which includes pumped storage, at 48,932 MW; nuclear at 44,264 MW, and other renewable energies at 4,717 MW (Figure 1).[1]

FIGURE 1

Installed electricity capacity in Japan by source (MW)



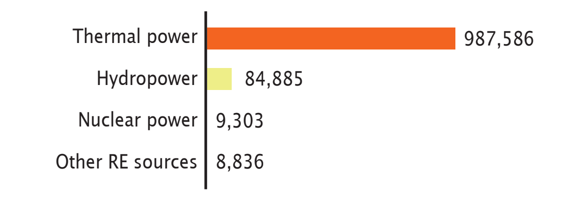
Source: Statistics Bureau[1]

In 2013, Japan generated 1,090,609 GWh of electricity: 987,586 GWh from thermal, 84,885 GWh from hydropower, 9,303 GWh from nuclear and 8,836 from renewable energy sources (Figure 2).[1]

In the last 50 years, the supply of power generation has increased corresponding to arising demand. In recent years, certain economic adversities, such as the global financial slowdown in 2008, led to a minor temporary decrease. Nevertheless, in general generation has stayed relatively the same.

FIGURE 2

Electricity generation in Japan (GWh)



Source: Statistics Bureau[1]

Petroleum was the main energy resource for both economic and industrial development during post-war Japan. The component ratio of fossil fuel power generation in 1973 was 74.6 per cent, allowing for a total of 244 TWh out of 328 TWh to be generated by general electricity utility. However, the first oil crisis triggered by Yom Kippur War in 1973 initiated the need for energy diversification.[2] Therefore, after the oil crises, nuclear and Liquefied Natural Gas (LNG) were introduced as alternative energy resources, and technologies were developed around them.

As a result, by 2010 the ratio of thermal generation from petroleum in the generation portfolio mix had reduced to 5.6 per cent, with 46 TWh out of 822 TWh. Correspondingly, generation by alternative resources increased, with use of LNG at 288 TWh—an increase of 35 per cent; nuclear energy at 271 TWh—an increase of 33 per cent; and coal at 146 TWh—an increase of 17.8 per cent.[2]

The Great East Japan Earthquake on 11 March 2011 triggered a catastrophic tsunami, resulting in nuclear power plants across the nation ceasing operation. As a result, the generation portfolio mix abruptly shifted, with mainly thermal generation covering for the lack of nuclear energy.

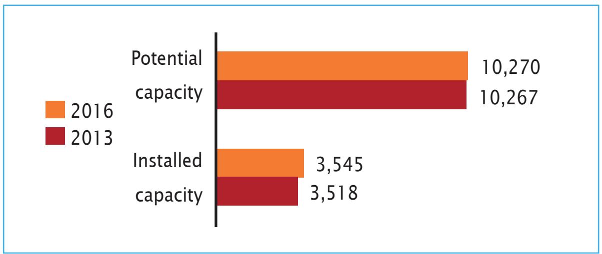
According to the International Energy Agency (IEA), the energy self-sufficiency rate of Japan stands at 6.0 per cent in 2012.[3] Energy self-sufficiency rate is defined as primary energy for livelihood and economic activity, secured within a country. Petroleum, coal and LNG are almost all imported. Present day Japan heavily depends on fossil energy and imported energy.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) used by Japan is up to 10 MW. In 2015 the Installed capacity of SHP in Japan was at 3,545 MW. A further 49 plants with a combined capacity of 54 MW are under construction and 2,456 potential sites with a combined capacity of 6,725 MW have been identified. This indicates that approximately 35 per cent of the country's SHP potential has been developed (Figure 3).[5]

FIGURE 3

Small hydropower capacities 2013-2016 in Japan (MW)



Sources: Agency for Natural Resources and Energy, METI,[5] *WSHPDR 2013*[18]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Compared with photovoltaic (PV) and wind power generation that have rapidly disseminated in Japan, especially in the last decade, hydroelectric power generation has more than 100 years of history of development. As a result, technology has already established a firm foundation.

In 1891 Kyoto Keage Hydropower Plant became the first Japanese hydropower plant in commercial operation. The plant provided power to general consumers and street-trains. After several facility enhancements, the plant still remains in operation today.[15] From 1910 to 1925, nearly 100 hydroelectric power plants were built annually, producing up to 1 MW on average. In 1925, the number of power plants in Japan was over 1,000. Due to the rapid increase of power plants, its corresponding technology also grew quickly. In the post war period of 1945, and during economic recovery, the national goal was set to have efficient and large scale of power generation by applying fossil fuel, gas, and nuclear energy instead of coal and woody biomass.

Hydropower generation was in existence all over Japan. However, it was considered as an inefficient power resource with the exception of large-scale dam based developments. Therefore, new development gradually subsided in the sector, with a large number of hydroelectric power plants being decommissioned during the 1960s and the 1970s. In the last 50 years, development of small hydroelectric power generation has been stagnant and technology, knowledge, and local wisdom succession effectively depleted.

It was not until 1990-2000 that hydropower (especially SHP) again attracted attention as a possible solution to climate change and greenhouse gas (GHG) emissions, as these became global issues. In 2010, SHP sector together with the woody biomass sector were reassessed, gaining new positions as natural energy resources that can be developed, while at the same time revitalizing the local community.[4]

Hydro energy potential is determined by drop and flow. Therefore, the amount of potential energy is determined precisely by topology. Five national hydropower potential research studies have been conducted to date. The first study took place from 1910 to 1913, the second from 1918 to 1922, the third from 1937 to 1941, the fourth from 1956 to 1959, and the fifth from 1980 to 1985.

All the research studies aimed to assess theoretical, technical, and economic potential of the development viability of hydropower, as well as capacity. However, the fifth research study was an exception to this aim, with the focus being on the utilization of generated electricity. In addition, the fifth analysis also looked at the effective utilization of hydropower resources and its harmonization with the natural and social environment. The overall assessment concluded that there is a hydropower potential at 46,020 MW. The total output of developed hydropower plants over 10 MW (including those under construction) is about 19 GW, which constitutes 78 per cent of the total large hydropower development potential. Further developments of large-scale hydropower are limited.[5]

When we focus on the potential under 1 MW, the Agency of Natural Resources and Energy estimates that the total output of the developed hydropower plants is at 480 MW in 948 places.[5] However, a separate research conducted by the Ministry of the Environment includes man-made irrigation canals and potential installation of under 1 MW in their study which brings the potential up to 5,300 MW in a total of 18,229 places.[6] It is clear, therefore, that untapped hydropower potential in Japan is concentrated in SHP especially that below 1 MW.

Renewable energy policy

The national policy from 1970-1980 was aimed at reducing its dependency on petroleum; which prompted development of alternative energy resources. Alternative energy resources, by definition, include new energy resources such as LNG, nuclear, and improved coal technologies. New energy combined with renewable energy makes up alternative energy resources.[7]

In 2008, the New Energy Law was put into effect in order to establish special measures for promoting the use of new energy, whereby the concept of new energy was also re-defined. Based on the new classification, renewable energy is defined as solar energy generation, solar energy utilization, wind power generation, biomass generation, biomass thermal utilization, biomass fuel production, thermal energy conversion, geothermal power generation (binary system) and small hydroelectric power generation (under 1 MW).[7] The following are policies developed for the generation of new energy:

- RPS (Renewable Portfolio Standard; 2003)[8]
  The RPS law, which came into effect in 2003, targets development of SHP under 1 MW. However, it has not shown a satisfactory level of development in SHP generation.
- FIT (Feed-in Tariff; Jul, 2012)[9]
  FIT was placed into effect in July 2012, and it requires electric utility companies to purchase electricity produced from renewable energy sources with a higher price than that of conventional fossil fuel based energy. Additional cost of the purchase was added onto the electricity bill. FIT is designed so that governments at all levels have a mandate to promote and spread the use of renewable energy.

Tariffs are set for each renewable energy category, and are revised each year based on a degree of circulation and market conditions of each category. Tariffs for each category (as announced in 2013) varied with the energy source. In regards to wind power, the tariff was between 22 yen/kWh (approximately US$0.18/kWh) for a wind power over 20 kW, to 55 yen/kWh (approximately US$0.46/kWh) for wind power under 20 kW. Tariffs for hydropower varied between 24 yen/kWh (approximately US$0.20/kWh) for small to medium hydropower plants, 1 MW-30 MW, to 34 yen /kWh for plants under 200 kW. The purchase period set for tariffs are 20 years.

Certified capacities were installed under FIT by METI, and were as follows: from July 2012 to April 2015, photovoltaic (PV) was at 82,470 MW, wind power was at 2,320 MW), hydropower was at 660 MW, and geothermal was at 70 MW.

Renewable energy generation itself is increasing, especially in the PV category. Hydropower generation, however, is confided to a limited number. The FIT scheme covers the output of below 30 MW for hydropower under three categories based on size of output. Facility is now over 600 MW, and is expected increase in the next few years.

However, FIT has not been as effective in development of hydropower compared to, for example, PV. This is partially due to the time it takes to build local awareness, consensus and plan (including a community development scheme).

Barriers to small hydropower development

The barriers to installing SHP are complex with factors that include technical, legal, social and human resources. This section examines the tasks that are necessary to install SHP in both technical and social contexts.

Post-World War 2 changes in the energy sector initiated a concentration on the development of large-scale power generation and energy conversion. Under those circumstances, there was a lack of interest and opportunity to implement 'small' hydropower; an energy that once boasted a high level of technology. Therefore, in the last 50 years, development in SHP technology has stalled.

The lost 50-year period has caused technology development to freeze. Moreover, the knowledge base that once existed in the prime age of the sector has not been succeeded by younger generations. Additionally, a lack of skilled personnel and technology has led to insufficient capacity in making an accurate assessment of appropriateness when regarding site selection, planning and design. This bottleneck is a major constraint toward implementation of SHP installation.

Other technical constraints include challenges in profitability of small-scale generation of electricity; this is due to the conventional profit margin relative to the scale of the power output. The lack of sufficient facilities is another issue, especially in new areas where hydropower plants have a small discharge and a low head.

Historically, small-scale hydropower plants have developed and improved with community based technology. Therefore, the technology should be utilised to build-up local industry effectively. An attempt to reproduce lost technology through a technology exchange programme has been established with Asian and European networks.[10,11]

When development of SHP is considered, a focus should be on those who receive the benefits from it. A problem exists in procedures to obtain rights and or permissions to use local resources, as well as challenges in consensus building and social recognition of use of local resources.

A small country like Japan has varying history in the use of the water. In 1896, Japanese River Act, the basic law of river and water resources management, came into effect (fully revised in 1994, revised partially in 1997). Since then all ground water flow is basically managed under the water rights by the national government.[12]

Ever since the River Act came into effect, all river projects are recognised as projects deeply related to development of the social-economy, therefore flood control and water rights are set under control of the national government.[12] In contrast, agricultural water that had been used before 1896 has a guaranteed existing right of use. This right belongs to local water right associations and is controlled and managed by its members.[12]

These underlying rules and practices are still effective today. When water is in need for power generation, it is necessary to:

- Build consensus with existing water users and negotiate water use rights;
- Obtain permissions for water usage that are based on river engineering and river planning.

Conflicts over ownership and the use of water have been recurring since the dawn of country's history, thus addressing conflict is and obtaining the consensus is an essential step. When obtaining permissions usage, 10 years of prospective water intake should be computed with additional information on flow rate. This data will be useful for predicting the possible effects on the natural environment and the eco-system beyond

As described above, the current water supply policy under government control oriented toward protecting water resources acts as a hurdle in utilizing water to develop SHP generation.[12] In the revised River Act of 1997, a description of conservation and control of environments surrounding rivers was added, while local community-based and grass-roots movements were to be organized as operating institutional bodies.

The most important human and social task is to overcome the insufficient human resources in coordinating production and planning of sustainable SHP, especially at local level. Planning for SHP requires that technical, social and legal aspects be unified in one single plan.

Understanding the ecological systems in the country and the potential risks to the natural environment are required for utilizing local resources. To utilize local resources, there needs to be a consensus built over the generation as well as clarification on who the users are and what the power is going to be used for. At this point local people should be encouraged to join the process of developing their community by utilizing small hydro energy as a powerful resource.[4,13]

Another important aspect here is to train people as coordinators or planners, so that they become "social entrepreneurs" who will be able to solve issues relating to utilization of their local resources. The important task is to promote installation of SHP generation by accumulation and integration of technology, along with the wisdom and social entrepreneurship of the operating body.[14]

SHP is a community-based resource. Therefore each community needs to be the operating body in order to circulate the expertise as well as the capacity to control and utilize resources. The local community is the appropriate body for controlling a SHP as local energy resource.

From the legal and social point of view, consensus-building and realignments of rights with comprehensive water users should also be emphasized. Rule-making based on public interest is vital.

Ongoing SHP projects in Japan will continue to be local community-based endeavours, as they have been in the past. Best practices brought about by front-runner communities utilizing natural resources such as water to create self-supporting energy provision mechanisms can assist in development of further SHP plants in other regions of Japan. We should bring SHP into practice and specifically into the community, to help them exchange technology expertise needed in the field.

Note

The author expresses special thanks to Hisashi Kobayashi (Ibaraki University) and Hiroshi Oishi (UNIDO) who gave useful advice for this report.

3.2.4 Mongolia

Makhbal Tumenjargal, Ministry of Energy of Mongolia

Key facts

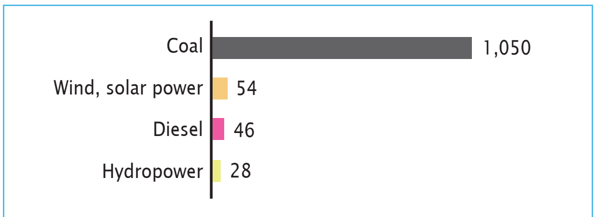
Population	3,057,778[1]
Area	1,564,120 km[2]
Climate	The climate of Mongolia is continental and has four distinct seasons. The temperature in winter is approximately -25°C to -32°C and in summer 25°C to 32°C. Mongolia has an extremely harsh winter climate with daytime temperatures ranging from -10°C to -30°C (late December and January). Temperatures can drop to as low as -40°C at night in January.[3]
Topography	The topography of Mongolia consists mainly of inter-mountain plateaus with about 80 per cent of the territory lying above 1,000 metres above sea level. The main mountain ranges in the country are the Altai Mountains in the southwest and the Khangai and Khentii Mountains in the north and centre. The highest point in Mongolia is Khüiten Peak at 4,374 metres above sea level. Mongolia can be divided into four geographical regions: Khangi forest region, the eastern steppe region, the semi-desert region and Gobi desert region.[4]
Rain pattern	Winters are dry, and summer rainfall seldom exceeds 380 mm in the mountains, and 125 mm in the desert.[3] The average annual precipitation is 241 mm.[4]
General dissipation of rivers and other water sources	There are 4,113 rivers in Mongolia with a total length of 67,000 km. The country is situated on three international river basins: the Yenisei River Basin in the centre and the north, the Amur River Basin in the east and the Central Asian Internal Drainage Basin in the south and west. The longest river is the Orkhon (1,124 km) originating in the Khangai Mountains.[4]

Electricity sector overview

In 2015 the total installed capacity of Mongolia was 1,178 MW with coal-fired combined heat and power (CHP) plants accounting for almost 90 per cent of it (Figure 1). However, due to losses from aged plants and transmission systems, the actual available capacity is lower.[6]

FIGURE 1

Installed capacity in Mongolia (MW)



Source: Ministry of Energy[5]

In 2014 Mongolia generated 5,392 GWh of electricity, of which 5,191.3 GWh was from coal, 8.2 GWh from diesel, 66.3 GWh from hydro and 126 GWh from wind and solar energy sources.[5] During the winter season, in order to meet the country's peak demand, electricity is imported from Russia and China.[7] The national electrification rate is 90 per cent, with 99 per cent electrification in the urban areas, and 70 per cent in the rural areas.[2]

There are five energy systems operating in Mongolia, the largest of which is the Central Energy System (CES). The smaller energy systems are the Western Energy System (WES), the Altai-Uliastai Energy System (AUES), the Dalanzadgad Energy System (DES) and the Eastern Energy System (EES). Except for WES delineated by a mountain range, the other four energy systems were developed historically around coal supply zones.[7]

With its five CHP plants of 987.3 MW, CES accounts for approximately 84 per cent of the country's total installed capacity. It covers the energy demand of Ulaanbaatar and 14 provinces. WES covers three provinces and has one hydropower with an installed capacity of 12 MW. In EES, comprising two provinces, electricity is generated by one CHP. AUES has six hydropower plants with a combined installed capacity of 14 MW and diesel generators, and it covers two provinces. Finally, DES has two CHPs (27 MW of combined capacity) and covers the energy demand of Oyutolgoi copper mine deposit.[5] Being interconnected with the Russian power system, WES and CES are heavily dependent on imported energy. There are also small capacity cross-border inter-connections with China in the provinces of Hovd and Omnogobi (South Gobi).[7]

The electricity sector of Mongolia is dominated by commercialized state-owned enterprises. The country's first independent power producer (IPP) was the Salkhit wind farm, which has a capacity of 50 MW and is connected to the CES grid.[7]

The energy sector is regulated by the Energy Regulatory Commission (ERC), which is an independent authority nominated by the Government. It is responsible for the regulation of energy generation, transmission, distribution, dispatching and supply, including licensing and setting tariffs in the electricity sector. The country's electricity market is based on the Single-Buyer Model (SBM), according to which electricity produced by five power plants operating in the central region as well as imported electricity is bought and sold to distribution companies by a single buyer, the Central Regional Electricity Transmission Network.[8] One of the main objectives of the ERC is to implement the transformation of the energy sector of Mongolia into a market-oriented system.

The Ministry of Energy (MOE) is in charge of the country's policies on development of energy resources, energy use, energy import and export, construction of power plants, lines and networks, energy conservation, use of renewable energy sources, monitoring of the sector, approval of rules and regulations for the sector and international cooperation.[8]

Development of renewable energy in the country is managed by the state-owned National Renewable Energy Corporation (NREC). NREC manages scientific research, experimental and construction works, trade, and production of renewable energy equipment as well as ensures efficient use of renewable energy resources. Therefore, the overall mission of NREC is to ensure sustainable and balanced economic and energy development through the use of ecologically-clean renewable energy.[8]

Electricity tariffs in Mongolia differ according to the consumer type, location and time of the day. Thus, the tariff for residential consumers in the Central System Area is MNT 128.5/kWh (US$0.064/kWh) for daytime consumption and MNT 77.1/kWh (US$0.038/kWh) for evening and night time consumption.[9] In the Western System Area a single tariff is applied to residential consumption – MNT 86.8/kWh (US$0.043/kWh).[10]

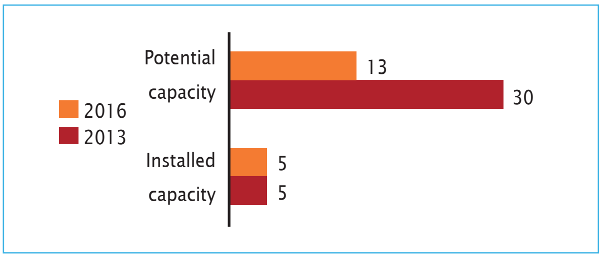
Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Mongolia is up to 10 MW. In total, there are 13 hydropower plants in Mongolia, of which 9 are operational. There are two large hydropower (Taishir of 11 MW and Durgun of 12 MW) and 11 SHP plants. The country's total installed hydropower capacity is 28 MW with SHP accounting for around 5 MW.[7] The large plants operate year-round and are connected to local grids, whereas small plants serve isolated district grids (Soum) and operate only in summer. Some of the SHP plants are no longer in operation due to technical failure.

Hydropower development in the country has been primarily focused on large hydropower schemes with the Government taking measures to perform feasibility studies of large hydropower sites with capacities above 100 MW, in particular on the Selenge, Eg and Orkhon Rivers. Other than those mentioned, there are no known new projects for further development of SHP.[8] The country has significant hydropower potential, which was estimated in 1994 by the Institute of Water Policy of Mongolia at 6,400 MW.[7] However, in 2013 the Ministry of Green Development reported that the country's actual hydropower potential is between 1,280 MW and 3,840 MW.[7] At least one potential SHP site has been identified on the Kherlen river with a capacity of 8 MW.[8] Therefore, the country's potential of SHP up to 10 MW is at least 13 MW. However, as of May 2016, no comprehensive data on the country's SHP potential is available (Figure 2).

FIGURE 2

Small hydropower capacities up to 10 MW 2013-2016 in Mongolia (MW)



Sources: Climate Investment Funds,[7] *WSHPDR 2013*[12]
Notes:
a. In *WSHPDR 2013* the Taishir and Durgun plants were included in the country's SHP potential.
b. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Renewable energy policy

The Government of Mongolia aims to increase the share of renewable energy sources in the country's energy mix, which is reflected in the following policies:

- The National Renewable Energy Program 2005-2020, which sets the following targets: achievement of 20-25 per cent share of renewable energy in the country's energy mix by 2020, improvement of the structure of power supply, use of renewable energy in off-grid areas, ecological balance and improved economic efficiency.
- The National Action Program on Climate Change (NAPCC) 2011-2021, the first phase of which (2011-2016) aims to mitigate the country's greenhouse gas emissions and establish a low carbon economy through environmentally friendly technologies and improved energy effectiveness and efficiency.
- The State Policy of Energy 2015-2030, which states that Mongolia will develop its institutional capacity, create a national database of renewable energy sources, perform research and development in the field of renewable energy, increase the share of renewable energy to 20 per cent by 2023 and to 30 per cent by 2030, build a favourable environment to attract investment, support use of new energy

sources in remote areas, mitigate the negative environmental effect of energy-related activities and improve environmental impact monitoring.

In 2007 Mongolia adopted the Law on Renewable Energy, which was further updated in 2015. The Law defines the feed-in-tariff (FIT) system applicable to renewable energy generators. According to the law, the tariffs are set by the Energy Regulatory Authority (ERA) within set limits for grid-connected and off-grid generators (Table 1).

TABLE 1

Feed-in-Tariffs for renewable energy sources in Mongolia

	Type of energy	Capacity (MW)	Tariff (US$)
Grid	Wind	—	0.08-0.095
	Hydro	up to 5	0.045-0.06
	Solar	—	0.15-0.18
Off-grid	Wind	—	0.1-0.15
	Solar	—	0.2-0.3

Source: Ministry of Energy[5]

Barriers to small hydropower development

There are a number of barriers that hinder further SHP development in Mongolia. First of all, the Government, aiming to improve the country's energy security and reduce its dependency on energy imports, gives priority to large hydropower projects. Secondly, renewable energy developers face a licensing ambiguity caused by the lack of criteria for rejecting new projects once the target levels for renewable energy in a given area have been exceeded. This affects licensed projects and results in the developers' inability to proceed with the planned installation. Thirdly, there is a lack of low-interest loans that could support small and medium scale companies interested in investing in renewable energy sources. Fourthly, the inability of the population to pay hinders construction of stand-alone renewable energy systems in remote areas. Finally, there are cases of abandoning renewable energy systems due to the lack of proper maintenance.

3.2.5 Republic of Korea

Deung-Yong Heo, Korea Institute of Local Finance

Key facts

Population	50,617,045[1]
Area	100,284 km[2]
Climate	The Republic of Korea has four distinct seasons, with humid hot summers and dry cold winters. The complex climate characteristics reveal both continental and oceanic features. The annual mean temperature ranges from 10°C to 15°C, with an exception in the high mountain areas. The monthly average temperature in August ranges from 23°C to 26°C, and in January, from -6°C to 3°C.[2]
Topography	The peninsula is predominantly mountainous, with flat land in the west and south; this accounts for only 30 per cent of the entire territory. Mountains over 1,000 metres above sea level make up only 15 per cent of the mountainous areas, while mountains lower than 500 metres account for 65 per cent. Elevations in the west part are generally lower than those in the east, with the highest point being on Mount Hallasan, at 1,950 metres.
Rain pattern	The East-Asian Monsoon gives the area a rainy period locally called Changma. Typhoons are common in the summer while heavy snowfalls usually occur in the winter. The annual precipitation ranges from 1,000 mm to 1,800 mm in the southern part, and from 1,100 mm to 1,400 mm in the central part. More than half of the annual precipitation falls during the Changma season when a stationary front lingers across the Korean Peninsula for about a month in summer. The winter precipitation is less than 10 per cent of the total annual precipitation.[2]
General dissipation of rivers and other water sources	South Korea has four major rivers. The Han River and the Kum River flow west to the Yellow Sea; and the Naktong River and the Somjin River, which flow south to the Korea Strait. River flow is highly seasonal, with the heaviest flows occurring in the summer months. During much of the year, however, the rivers are shallow, exposing very wide, gravelly river beds. The Naktong River Basin in the south-east is a complex of structural basins and river floodplains separated from one another by low hills. The Naktong River is the longest river in South Korea, extending about 521 kilometres. It forms a wide delta where it reaches the sea, a few kilometres west of Pusan, South Korea's major port.[18]

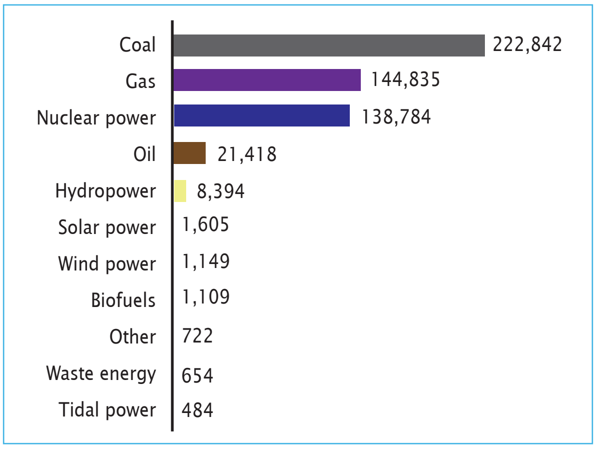
Electricity sector overview

The installed electricity generation capacity of the Republic of Korea in August 2015 was 96.83 GW while the available capacity was 89.60 GW, mainly due to the aged equipment. The country's hydropower installed capacity is 1,644 MW; there are also pumped-storage plants with a total capacity of 4,700 MW.[12] In 2013 total electricity generation was at 541,996 GWh (Figure 1).[17] The Republic of Korea remains one of the top energy importers in the world with an energy import dependency at 97 per cent, due to its insufficient domestic resources.[5] According to the World Bank's Global Electrification Database, the country's electrification access is 100 per cent.[6]

Annual electricity consumption on average has rapidly increased by 5.9 per cent from 239,535 GWh in 2000 to 434,160 GWh in 2010.[1,4] The electricity consumption growth rates in Chungcheongnam-do Province located in the mid-western part of the country was 18.93 per cent because of the relocation of the administrative capital and public agencies to the region in 2010.

FIGURE 1

Electricity generation in Republic of Korea (GWh)



Source: IEA (2013)[17]

Since the rolling blackout in September 2011, the Government has implemented a strong electricity demand management and increased electricity price, hoping to decrease the electricity consumption growth rate. The average annual electricity consumption growth rate was only 3.0 per cent from 455,070 GWh in 2011 to 474,849 GWh in 2013.[4] No alert for available generation shortage has been issued since 2014. Forecasted electricity demand, summer peak load and winter peak load are expected to be 498,000 GWh, 80,641 MW and 83,250 MW in 2015 and 766,109 GWh, 126,338 MW and 127,229 MW in 2029, respectively (average annual growth rates are 3.1 per cent, 3.3 per cent, and 3.1 per cent respectively). Forecasted target electricity demand in the summer peak load and winter peak load were lower than the usual ones due to demand-side management. They are expected to be 489,595 GWh, 79,923 MW and 82,478 MW in 2015 and 656,883 GWh, 111,145 MW and 111,929 MW in 2029 respectively (average annual growth rates: 2.1 per cent, 2.4 per cent, and 2.2 per cent respectively).

In order to meet the growing electricity demand, there is a plan to increase installed capacity to 136,097 MW by 2029 (average annual growth rate: 2.8 per cent) and reserve rate from 12.1 per cent to 21.6 per cent by 2029.[8] Transmission lines, mostly for 154 kV and 345 kV, will be increased based on the Basic Plan for Electricity Supply and Demand, one of the Government's plans to meet the growing electricity demand. Meanwhile, transmission and distribution lines are already efficient: losses on transmission and distribution were 1.59 per cent and 2.14 per cent respectively in 2014.[9]

The country's electricity market was partially liberalized in 2001. In April 2001 the Korea Electric Power Corporation (KEPCO), the sole electric power utility corporation of the Republic of Korea, was split into six subsidiaries (five thermal and one hydro and nuclear). At present, in the domestic electric power industry, those six companies, independent power producers, and community energy systems, are the major electric power producers. KEPCO purchases electricity from the Korea Power Exchange and transports it through its transmission and distribution network, and sells it to general customers under government supervision.[7] Installed capacity of KEPCO and its subsidiaries was 74.3 per cent of the total capacity, generating 90.2 per cent of the total electricity in 2014.[9]

As for the electricity price, it is regulated by the Government; the electricity price is basically the same across the country and it differs only by usage. The electricity usage is classified into six categories and the prices become lower based on the following order: residential, general, educational, streetlight, industrial, and agricultural usage. Unlike in the past when electricity price growth rate was maintained low through government efforts, lately it has been increasing relatively fast after the rolling blackout in September 2011. Given the average KRW to US$ exchange rate (KRW 1,053.21 per US$1) in 2014, the average nominal electricity price was KRW 7,706 (approximately US$7.3) per 100 kWh in 2001 and KRW 8,932 (approximately US$8.5) per 100 kWh in 2011 (average annual growth rate: 1.5 per cent). Real electricity price growth was negative, considering that the average annual Consumer[1] Price Index (CPI) growth rate was 3.1 per cent during the same period. Average annual growth rate was 7.3 per cent from 2011 to 2014, while average annual CPI growth rate was 1.6 per cent during the same period.[1,9]

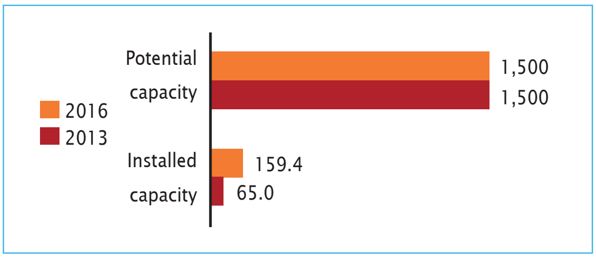
As is the case with other countries, the electricity sector in the Republic of Korea faces several challenges. First, global warming causes abnormal weather conditions, which need to be considered when forecasting electricity demand. Second, the fuel mix for electricity generation needs to be diversified to reduce carbon emissions by installing more renewable energy resources and increasing supply elasticity of electricity. Third, a smart grid needs to be integrated into the conventional electricity system to increase its efficiency.

Small hydropower sector overview and potential

The Republic of Korea does not have a definition of small hydropower (SHP). For this report, 10 MW and below will be considered its definition. The installed capacity of SHP in the Republic of Korea is at 159.39 MW as of 2014, while the potential is estimated to be 1,500 MW indicating that less than 11 per cent has been developed. Between the 2013 and 2016 *World Small Hydropower Development Reports* the installed capacity has increased while estimated potential has not changed (Figure 2).

FIGURE 2

Small hydropower capacities 2013-2016 in Republic of Korea (MW)



Sources: *WSHPDR 2013*,[20] Electric Power Statistics Information System,[12] Lee, Gyeong-Bae[13]
Notes:
a. Data from 2014. Economical potential measured based plan for 2030.
b. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Until 2005, a hydropower unit with a total capacity of no more than 10 MW was classified as a SHP plant in the Republic of Korea. However, it is no longer the case and every type of generation that generates electricity based on water flow is referred to as hydropower. This change was following the Promotion of the Development and Use of New and Renewable Sources of Energy Act, which was revised in 2005.[10] However, for the sake of convenience, this report follows the old classification. The Government focused its research and development efforts on SHP and tried to disseminate it for its cost and environmental benefits compared to those of large hydropower. In terms of Renewable Energy Credits (RECs), only SHP units with a capacity of no more than 5 MW are able to trade for credits.[10]

SHP plants are located on 108 sites nationwide. The total installed capacity of SHP was 159.39 MW in 2014. The public sector (K-water, KEPCO and its subsidiaries, Korea Rural Community Corporation and local governments) has 78 per cent of total SHP capacity (Table 1).

TABLE 1

Installed small hydropower in Republic of Korea (kW)

Owner	Number of SHP	Capacity (kW)	Share (%)
K-water	42	70,790	44
KEPCO and its subsidiaries	17	38,117	24
Private company	23	35,044	22
Korea Rural Community Corporation	13	8,114	5
Local governments	13	7,295	5
Total	**108**	**159,360**	**100**

Source: Electric Power Statistics Information System (2014)[12]

SHP installed capacity was only 0.16 per cent of total installed capacity and accounted for only 0.12 per cent of total generation (615,737 MWh) in 2014.[12] The technical potential of SHP plants from rivers is 1,412 MW. If the rivers' SHP potential is combined with that of other existing water-related facilities such as sewage treatment plant, water treatment systems, irrigation reservoirs, multi-purpose dams and irrigation dams, the total SHP potential could be up to 1,500 MW. Also, SHP economical potential is known to be 660 MW, leaving 1,341 MW of extra technical potential and 501 MW of extra economical potential to be exploited.[13] The number of SHP constructed from 2012 to 2014 was 44 and their total installed capacity was 9,381 kW. In the meantime, the Government plans to increase SHP generation to 1,926.17 GWh by 2030.[13]

The Government has strongly implemented the Low Carbon Green Growth policy to prepare for global warming, and to financially support SHP to reduce carbon emissions. Cumulative government subsidies to SHP construction were KRW 29 billon (about US$27.5 million) and financial support for SHP installation was KRW 71 billion (approximately US$67.4 million) by 2014.[10] The REC price was over KRW 8,000 (about US$7.6) per 100 kWh in 2014. In addition to these financial aids, the increase in the electricity wholesale price (called System Marginal Price; SMP) caused by the demand growth and the decrease in the cost of SHP installation caused by domestic water wheel technology development provide a favourable investment environment to generation corporations, private companies and local governments.[10]

Renewable energy policy

The Government of the Republic of Korea enacted The Alternative Energy Development Promotion Law and started the commercialization and spread of solar and waste energy after two oil crises with the aim to diversify energy production and consumption. With the goal of replacing 11 per cent of the primary energy supply with new and renewable energy supply by 2035, the Government finalized The Fourth New & Renewable Energy Development Framework in September of 2014. It will be achieved by gradually expanding the proportion from 3.2 per cent in 2012 to 3.6 per cent in 2014, 5 per cent in 2020, 7.7 per cent in 2025 and 9.7 per cent in 2030. According to the schedule, the year-on-year supply increase of new and renewable energy from 2014 to 2035 may reach 6.2 per cent, which is a relatively high increase given the goal of a 0.7 per cent supply increase for the primary energy group. Furthermore, the Government plans to reduce the amount of waste energy that accounts for two-thirds of the entire new and renewable energy supply, and intends to focus on promoting the supply of photovoltaic and wind power energy. With respect to monthly proportions, the proportion of waste energy in 2012 was 68.4 per cent, and it will be reduced to 29.2 per cent by 2035. The Government plans to expand the proportion of wind power from 2.2 per cent in 2012 to 18.2 per cent in 2035, and that of photovoltaic from 2.7 per cent to 14.1 per cent (Table 2).[7,15]

TABLE 2

Goals for each source of energy in Republic of Korea

Items	2012	2014	2025	2035	Annual growth rate, %
Solar heat	0.3	0.5	3.7	7.9	21.2
Photovoltaics	2.7	4.9	12.9	14.1	11.7
Wind power	2.2	2.6	15.6	18.2	16.5
Biofuel	15.2	13.3	19.0	18.0	7.7
Hydropower	9.3	9.7	4.1	2.9	0.3
Geothermal heat	0.7	0.9	4.4	8.5	18.0
Maritime	1.1	1.1	1.6	1.3	6.7
Waste energy	68.4	67.0	38.8	29.2	0.2

Source: Ministry of Trade, Industry and Energy (2014)[7]

The Government runs a loan support program for the new and renewable energy (NRE) industry. The program is designed to offer long-term, low-interest rate loans to NRE system installers and producers so that they can cut back on their initial investment costs and secure economic efficiency, eventually promoting not only the NRE equipment business but also other related industries. Meanwhile, as a part of general supports for the NRE promotion, the Government pays a certain portion of the installation costs for NRE equipment free of charge to promote the commercialization of products developed in Korea and to create and boost the initial market. The Government pays up to 60 per cent of the equipment cost to any commercialized ordinary, internal NRE supply system. Lastly, the Government pays up to 80 per cent of the pilot supply equipment cost (limited to the internal system), on the condition that the government R&D system is used.

As a part of its effort to encourage public organizations to lead the way in the new and renewable energy use, the Government mandates public institutions to use the energy. In order to create one million green homes by 2020, the Government offers to pay a certain portion of the power generation equipment cost for houses that install new and renewable energy, including photovoltaic, solar heat, geothermal heat, small wind power, and bio sources.[7,15]

Barriers to small hydropower development

The Republic of Korea has three main barriers to SHP development. First, the country's topographical features hinder the high head turbine installation. Second, the local SHP industry has yet to be fully developed. Third, the Government intends to focus on promoting photovoltaic and wind energy supply, which can lead to the reduction of the Government subsidies and financial supports for SHP.[15] These three factors limit economic feasibility of SHP projects in the Republic of Korea.

3.3 Southern Asia

Arun Kumar, Indian Institute of Technology Roorkee

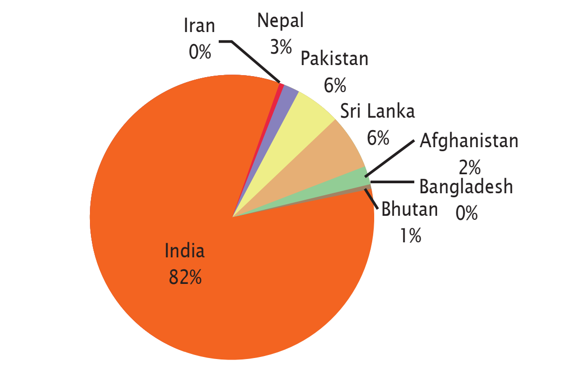
Introduction to the region

The region of Southern Asia comprises nine countries: Afghanistan, Bangladesh, Bhutan, India, Iran, Maldives, Nepal, Pakistan and Sri Lanka. This Report covers the eight countries of the region that have hydropower potential, i.e. all the countries except Maldives.

There is a huge diversity of resources in the region. India, Iran, Pakistan and Bangladesh account for major natural gas and coal resources, whereas Bhutan and Nepal have large hydropower resources. All the countries have vast renewable energy potential.

FIGURE 1

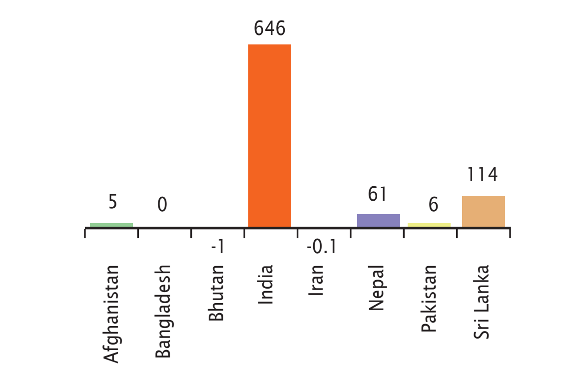
Share of regional installed capacity of SHP by country



Source: *WSHPDR 2016*[1]

FIGURE 2

Net change in SHP from 2013 to 2016 for Southern Asia (MW)



Sources: *WSHPDR 2013*,[2] *WSHPDR 2016*[1]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting. The data for India is for SHP <25 MW."

However, there is a wide variation in energy resource endowments and energy demand among the countries. Thus, in India, Pakistan and Bangladesh, domestic resource development pace cannot match the growing commercial energy supply required. On the contrary, Bhutan and Nepal have hydropower potential in excess of their demand for electricity. This creates opportunity for intraregional energy cooperation and pushes the countries to search for optimal energy supply solutions for the entire region.

TABLE 1

Overview of countries in Southern Asia (+ % change from 2013)

Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Afghanistan	31.63 (+5%)	74 (-3pp)	43 (+27.5pp)	522 (-36%)	1,120 (+33%)	254 (-37%)	961 (+20%)
Bangladesh	160.41 (+13%)	70 (-2pp)	74 (+33pp)	11,552(+72%)*	40,296 (+9%)	230 (0%)	588 (-51%)
Bhutan	0.75 (+6%)	62 (-3pp)	95 (-)	1,623 (+8%)	7,550 (+3%)	1,614 (+8%)	7,549.5 (+3%)
India	1,210.60 (+5%)	68 (-2pp)	78 (+3pp)	278,733 (+31%)*	1,179,256 (+45%)	41,810 (+24%)	134,731 (-)
Iran	78.52 (+8%)	27 (-2pp)	98 (-)	70,270 (+13%)	262,192 (+19%)*	9,500 (+12%)	12,400 (-31%)
Nepal	28.28 (-2%)	82 (+1pp)	71 (+27.4pp)	787 (+23%)	3,550 (+17%)*	732 (+10%)	3,540 (+47%)
Pakistan	188.02 (+11%)	61 (+3pp)	67 (+4.6pp)	24,953 (+12%)	111,139 (+6%)	7,087 (+8%)	32,239 (+15%)
Sri Lanka	22.05 (+10%)	82 (-4pp)	98 (+21.4pp)	4,044 (+28%)*	12,849 (+30%)	1,665 (+23%)	4,534 (-20%)
Total	**1,720.26 (+6%)**	—	—	**392,484 (+27%)***	**1,614,460 (+35%)***	**62,892 (+19%)**	**196,543 (-)**

Sources: Various[1,2,3,4,5,6,7,8]
Notes:
a. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. The large differences and negative changes can be due to access to more accurate data.
b. An asterisk (*) indicates data compared to the 2013 country report instead of the regional summary.

Energy sector cooperation in the region is focused on such issues as developing a regional power market, energy supply availability, energy trade infrastructure and harmonizing legal and regulatory frameworks. Moreover, there is also potential for inter-regional cooperation with neighbouring regions, in particular, Central Asia and Western Asia.[9]

In Southern Asia, the lowest electrification rate of 43 per cent is reported in Afghanistan, which is, however, a considerable increase for the country compared with 15.5 per cent reported in the *World Small Hydropower Development Report* (*WSHPDR*) *2013* (Table 1).[2,3]

Small hydropower definition

Classification of small hydropower (SHP) varies from country to country, with the upper limit ranging from 10 MW to 50 MW (Table 2). Bangladesh has no official definition or classification of SHP.

TABLE 2
Classification of SHP in Southern Asia

Country	Small	Mini	Micro	Pico
Afghanistan	1-10 MW	100 kW-1 MW	5 kW-100 kW	up to 5 kW
Bangladesh	—	—	—	—
Bhutan	1-25 MW	100 kW-1 MW	10 kW-100 kW	up to 10 kW
India	2-25 MW	101 kW-2 MW	up to 100 kW	up to 5 kW
Iran	1-10 MW	101 kW-1 MW	up to 100 kW	—
Nepal	1-10 MW	100 kW-1 MW	10 kW-100 kW	up to 10 kW
Pakistan	5-50 MW	150 kW-5 MW	up to 150 kW	—
Sri Lanka	1-10 MW	101 kW-1 MW	up to 100 kW	—

Sources: *WSHPDR 2016*,[1] *WSHPDR 2013*,[2] Nepal Micro Hydropower Development Association[10]

Regional SHP overview and renewable energy policy

The region's climatic and physiographic settings create favourable conditions for hydropower development. Hence, all countries of the region except Maldives have developed SHP. Compared with *WSHPDR 2013*, the total installed capacity of SHP in the region decreased by 34 per cent and was 2,973 MW (Table 3).

The regional leader in terms of SHP is India with an estimated SHP potential of 21,425 MW (up to 25 MW), of which 19 per cent has been developed. The country's SHP programme, controlled by the Ministry of New and Renewable Energy, heavily relies on private investment. As a result, the major focus of the programme is to make SHP projects cost effective and reliable. For this purpose a range of documents have been issued covering various aspects of SHP activities for the use of developers, manufacturers, consultants and regulators.

TABLE 3
SHP in Southern Asia (+ % change from 2013)

Country	Installed capacity (MW)	Potential (MW)
Afghanistan (< 10 MW)	80 (+6.5%)	1,200 (0%)
Bangladesh (< 10 MW)	0.05 (-)	1.4 (-)
Bhutan (< 25 MW)	32.1 (-2%)	93 (+90%)
India (< 25 MW)	2,119 (-33%)	11,914 (-20%)
Iran (< 10 MW)	16.4 (-0.6%)	49.9 (+31%)
Nepal (< 10 MW)	131 (+86.5%)	1,430 (0%)
Pakistan (< 50 MW)	287 (+2%)	2,266 (0%)
Sri Lanka (< 10 MW)	308 (+59%)	873 (+118%)
Total	**2,973.65 (-22%)**	**17,825.4 (-12%)"**

Sources: *WSHPDR 2016*,[1] *WSHPDR 2013*[2]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Sri Lanka has SHP plants with a total installed capacity of 288 MW, which accounts for less than 33 per cent of its potential. Development of SHP in the country is supported by the Sustainable Energy Authority (SEA), which aims to increase the share of renewable energy sources in electricity generation and promotes participation of private sector in renewable energy projects, including SHP.

Pakistan has a huge hydropower potential that is estimated to be 60,000 MW but SHP potential accounts for only 3 per cent thereof. So far, 13 per cent of the country's SHP potential has been developed with 287 MW of installed capacity. The Government aims to boost the renewable energy sector through such incentives as partial risk coverage, premium tariffs and guaranteed purchase. SHP projects in Pakistan are developed by provincial governments, in cooperation with public sector, individuals and communities as well as various organizations.

Nepal has an appreciable SHP potential and has extremely successful instances of implementing SHP programmes, especially micro hydropower plants in isolated rural areas. This makes SHP crucial for the country's rural development. The total installed capacity of SHP plants in Nepal is 131 MW, though part of them might have suffered significant damage from the earthquake in April 2015.

In Afghanistan, with the support of international institutions, the Government has developed 80 MW of SHP, which is about 7 per cent of the country's potential. Several more SHP projects are underway. Increasing access to electricity remains an important task for the

Government, therefore, with the limited reach of regional grids smaller scale off-grid units, including SHP plants, can play a significant role in the provision of energy.

Bhutan has four small and 18 mini/micro hydropower plants with the total installed capacity of 32.09 MW. No data on the country's SHP potential is currently available aside from estimates of 93 MW based on planned projects. However, due to its climatic conditions and mountainous terrain the total hydropower potential is estimated to be very high, at 30,000 MW.

For Iran the main source of electricity generation is fossil fuels and hydropower accounts for only 5 per cent of the generated electricity. However, the Government aims to increase the share of renewable energy sources. The total installed capacity of SHP plants has not changed compared with *WSHPDR 2013* and remains at 16.5 MW.

Finally, Bangladesh has a very limited SHP potential estimated at 1.4 MW. The current installed capacity is 0.05 MW with two operating SHP plants.

Barriers to small hydropower development

Most countries of the region have developed regulatory frameworks to facilitate SHP development, which has resulted in a significant increase in installed SHP capacity. However, countries still face a range of issues that hinder SHP development, including:

- Lack or instability of funding;
- Lack of qualified specialists;
- Inadequate technical capacity;
- Bureaucracy-related delays and complications;
- Lack of studies on SHP potential;
- Cost ineffectiveness of SHP;
- Lack of related infrastructure;
- Environmentalist opposition;
- Limited water resources;
- Political instability;
- Poor power evacuation arrangements;
- Risk of earthquakes and landslides;
- Low tariffs.

3.3.1 Islamic Republic of Afghanistan

Marcis Galauska, International Center on Small Hydro Power; Ghulam Mohd Malikyar, National Environmental Protection Agency of the Islamic Republic of Afghanistan

Key facts

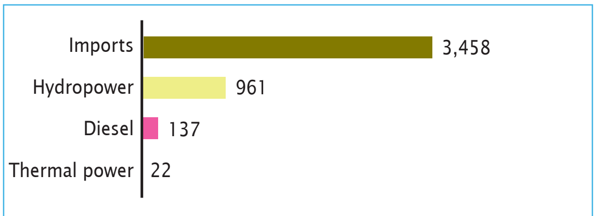
Population	31,627,506 [4]
Area	652,230 km²
Climate	Afghanistan is a mountainous and very dry country located in the arid sub-tropics at 29° to 37° north of the Equator. Afghanistan has an arid and semi-arid continental climate with cold winters and hot summers. The average temperature in summer (June to August) exceeds 33°C and winter (December to February) is around 10°C. Much of the country is at very high altitudes and experiences lower temperatures all year round, with average summer temperatures not exceeding 15°C, and winter temperatures below 0°C in the highest regions.[1]
Topography	Afghanistan is split east to west by the Hindu Kush mountain range, rising in the east to heights of 7,315 m. With the exception of the south-west, most of the country is covered by high mountains and traversed by deep valleys. Most of the land (some 63 per cent) is mountainous, using formal criteria based on slope and elevation, and more than a quarter (27 per cent) lies above 2,500 m.[1]
Rain pattern	More than 50 per cent of the country receives between 100 and 300 mm per year, the remaining 50 per cent, except Ghore and Bamyan, receive 300-800 mm per year.[1] On average, the wettest month is March (53 mm) and the driest is September (5.3 mm).[11]
General dissipation of rivers and other water sources	During the dry season most rivers in Afghanistan become little rivulets. The rivers are mostly supported by mountain streams. These rivers have decent flows in spring, when snow on the mountains melts. An exception among Afghan rivers, the Kabul River, maintains a steady flow year-round. It flows east into Pakistan to merge into the Indus River. The longest river in Afghanistan, the Helmand River, originates in the Central Hindu Kush mountains. The river flows past the south-west region of the country, ending in Iran. Rising in central Afghanistan, the Harirud River moves west and north-west to the border with Iran. The water of the Harirud River is used extensively for irrigation purposes in the Herat region.[2]

Electricity sector overview

Electricity generation in the Islamic Republic of Afghanistan (Afghanistan) 2013 was 1,120 GWh consisting of hydro (961 GWh), thermal (22 GWh), diesel (137 GWh), with an additional 3,458 GWh imported, making overall domestic supply 4,578 GWh (Figure 1). However, the actual demand was approximately 5,700 GWh.[10]

FIGURE 1

Electricity generation in Afghanistan (GWh)



Source: IEEJ[10]

Total installed capacity is 522 MW.[3] The electrification rate in Afghanistan is 43 per cent.[4] Imports satisfy a significant proportion of national energy consumption and this proportion is expected to grow. Power is imported via the North East Power System.[5]

In 2014 the World Bank Group's Board of Directors approved US$526.5 million in grant and credit financing for the Central Asia South Asia Electricity Transmission and Trade Project (CASA-1000) for four countries: Afghanistan, Kyrgyz Republic, Pakistan, and Tajikistan. Total cost of the project is US$1.17 billion (from the World Bank, the European Investment Bank, DFID, EBRD, The Islamic Development Bank). Official opening of the project is planned in May 2016. CASA-1000 will build more than 1,200 km of electricity transmission lines and associated sub-stations.[6] Da Afghanistan Breshna Sherkat (DABS) is an independent and autonomous company established under The Corporations and Limited Liabilities Law of the Islamic Republic of Afghanistan (IROA). DABS is a limited liability company with all its equity shares owned by the Government of Afghanistan. The company was incorporated on 4 May 2008 (15 Saur 1387) and replaced Da Afghanistan Breshna Moassassa (DABM) as the national power utility. DABS operates and manages electric power generation, import, transmission, and distribution throughout Afghanistan on a commercial basis.[7]

Seven regional electricity grids exist with supply coming from domestic hydro and thermal generation and imported power. The electricity infrastructure has suffered considerable damage due to decades of war and operational neglect. Blackouts are frequent because power plants are not fully functional and the transmission and distribution networks have been depleted. High electrical losses in distribution and transmission networks contribute to further inefficiencies in the energy supply chain. Despite Afghanistan having the lowest per capita energy consumption in the South Asia region, demand continues to outstrip supply in every fuel category. Average price for electricity is approximately US$0.17/kWh.

Recent government and donor initiatives have been focused on the expansion and rehabilitation of the electricity sector in the major economic hubs of Afghanistan as well as the provision of basic services in rural areas. Efforts have also been made to:

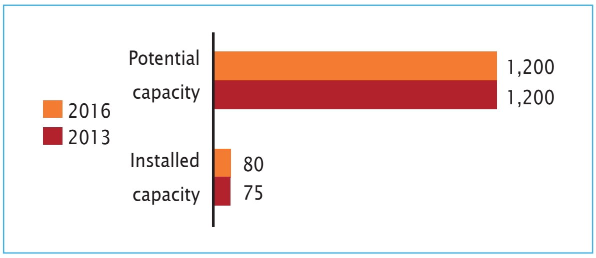
- Improve the supply of natural gas;
- Increase availability of hydro-electric generation;
- Rehabilitate the electricity transmission and distribution systems;
- Develop RES in rural and remote areas;
- Increase low-cost power imports; and
- Improve the capability of energy sector institutions.[5]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Afghanistan is up to 10 MW. Installed capacity of SHP in Afghanistan is 80 MW. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 6 per cent.

FIGURE 2

SHP capacities 2013-2016 in Afghanistan (MW)



Sources: *WSHPDR 2013*,[9] IJHD[8]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The SHP potential in Afghanistan is estimated to be 1,200 MW. While past studies have indicated that around 80 MW of small hydro is in operation, there could be more than 100 micro hydro schemes not included in the total.

The Energy Supply for Rural Areas programme, carried out with German assistance, entails building several mini hydro projects with more in the planning stages. General surveys and construction works are taking place in the Paktia, Kunar, Bamyan and Panjshir districts, to assess potential small and micro hydro sites. Micro hydro plants have also been tested in Badakshan province.[8]

Legislation on small hydropower

The National Rural Energy Strategy (2010) includes an Action plan until 2014, with the following actions:

- Training the private sector (hydropower turbine manufacturers, operators and hydropower engineering companies) on the delivery of high quality energy services in rural areas.
- Creating guidelines for the operation and maintenance of SHP plants (more than 1 MW) and basic electrification schemes (below 100 kW).
- Adapting international standards in rural renewable energy to Afghan National Standards via the Afghan National Standards Authority.

Renewable energy policy

The Environment Law of Afghanistan, which was promulgated in 2007 and is based on international standards, covers most of the aspects of natural resources management. The law requires planning for sustainable use, rehabilitation and conservation of biologic diversity. Environmental Impact Assessment (EIA), promulgated in 2008, established the process of conducting environmental assessments for development acitivities.[8]

The limited reach of regional grids means that smaller scale off-grid renewable energy (RE) technologies, such as small hydro, solar PV, solar thermal and wind, can play a significant role in the provision of energy. Afghanistan has significant renewable resources, primarily in the form of hydropower. It is estimated that 23,000 MW of hydropower resource potential are available. In mountainous areas there is sufficient head to make even very low flow streams effective, and glacier-fed streams provide year-round minimum water flow.

Solar resources are also good given the high altitudes and approximately 300 days of sunshine a year, which provide about 6.5 kWh/m^2/day. The wind power potential is high in Herat province but less so in other regions. Geothermal resources may also be feasible in the longer term.[5]

Barriers to small hydropower development

Barriers to SHP in Afghanistan should be seen in the wider context of barriers to rural renewable energy expansion, since micro to small hydropower is mostly used in rural areas:

- Weakness of the private sector for investment in rural energy, despite an increase in companies and entrepreneurs in recent years.
- Lack of important data for Afghanistan. For example, figures such as the total number of urban households, total number of non-residential establishments, and total number of rural households, as well as total cost of power import, generation, transmission, distribution, operation, maintenance and administration for the entire country, were not available. The demand for data such as the total actual electricity generation and the electricity generated based on renewable energy was reiterated in the National Rural Renewable Energy Strategy (2010) under objectives and indicators until 2020.
- Lack of involvement of international financial institutions with regard to support to the private sector in this area.
- Lack of concessionary loans (with sovereign guarantees) provided for rural electrification projects and major organizations with international involvement in infrastructure development, environmental protection and support for private sector development.
- Deficits in cash-flow: The Draft Electricity Law includes the agreed principle that the main instrument for financing operation and maintenance (including mini repairs of key components) should be cash-flow finance. Retail tariffs for electricity supply need to cover all operation and maintenance costs, but in reality, consumers are either unwilling or unable to pay for the full cost of supply, resulting in cash-flow deficits, and often a critical financial position of the utility or operator of an isolated mini-grid.
- Instability in the country is a constraint to the timely implementation of the Power Sector Strategy in some places.
- Limited technical human resources capacity (i.e. not enough trained personnel able to produce improved units from standard technical drawings).
- Licensing requirements: The draft Rural Renewable Energy Strategy requires operators of isolated mini-grids to be licensed, while considering affordability and financial requirements of the licensee, and the costs of four energy supplies based on the type of source. According to the Draft Electricity Law (2008), Article 13.9, there are no license requirements for the establishment/construction of electricity supply infrastructure. Furthermore, according to Article 14.3.3, electricity service companies that do not serve more than 1,000 customers and do not own more than 2 MW of installed capacity, based on their own sources of generation, do not require a generation or distribution license.[9]

3.3.2 Bangladesh

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Key facts

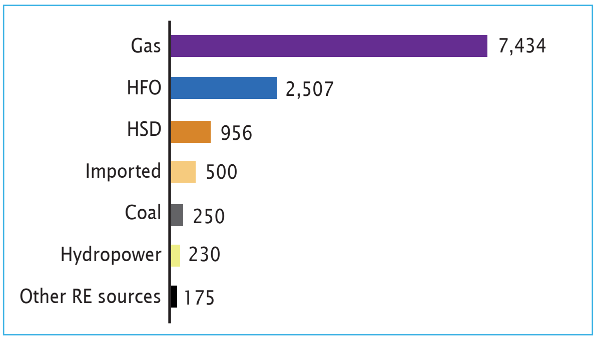
Population	160,411,249[1]
Area	147,570 km[2]
Climate	Bangladesh has a tropical monsoon climate characterized by wide seasonal variations in rainfall, high temperatures and high humidity. The average temperature varies between 11°C and 20°C in the winter months (December to February) and between 23.9°C and 31.1°C in the pre-monsoon summer months (March to May). Average humidity varies between 36 per cent in January and 99 per cent July.[3]
Topography	Situated on the deltas of large rivers flowing from the Himalayas, the topography of most parts of Bangladesh is extremely flat. Approximately 50 per cent of the country lies below 10 m and 90 per cent below 60 m above sea level. Approximately 10 per cent of the land, mostly located in the south-east and north-east, is considered hilly. At 1,052 m, the highest peak in Bangladesh, Saka Haphong, is located in the extreme south-east corner of the country.[4]
Rain pattern	The annual average rainfall is 2,666 mm. Rainfall varies from 1,400 mm in the north-west to approximately 4,400 mm in the north-east.[3] More than 78 per cent of the total annual rainfall occurs during the monsoon from June to October. Only 3 per cent occurs during the winter months of December to February.[3]
General dissipation of rivers and other water sources	The majority 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 all 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 km 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.[5]

Electricity sector overview

As of October 2015, the total installed electricity generation capacity in Bangladesh was 11,552 MW and the available capacity was 8,177 MW.[6] The total capacity consisted of natural gas accounting for 62 per cent, heavy fuel oil (HFO) 21 per cent, heavy fuel diesel (HFD) 8 per cent, coal 2 per cent, hydropower 1.9 per cent and other renewable energy sources 1.5 per cent (not connected to the national grid). In addition the equivalent of 500 MW was imported from India (Figure 1).[6]

FIGURE 1

Installed capacity in Bangladesh by source (MW)



Source: BPDB[6]

As of June 2015, the national electrification rate was 74 per cent (approximately 17.5 million consumers). However, the electrification rate in rural areas, where more than 70 per cent of the population lives, was just 50 per cent.[7,11] Per capita generation of electricity in Bangladesh was 371 kWh.

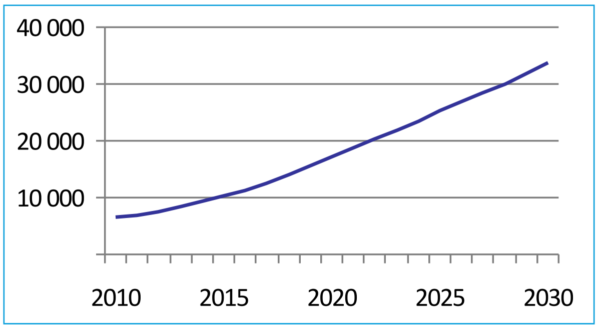
Limited access to electricity, supply-demand imbalance, high dependency on natural gas as an energy source and poor grid reliability are the major problems facing the power sector in Bangladesh. The major challenges are to provide universal access to reliable power supply, ensure availability of energy sources for power generation and long-term energy security.[8]

Electric power consumption in Bangladesh is rising by 9.6 per cent each year due to the rapid increase of consumers and GDP growth. The country's available power generation capacity has also risen markedly between 2010 and 2015 with an average growth rate of approximately 10 per cent; increasing generation is a major agenda for the Government which aims to provide 100 per cent access to affordable and reliable electricity by 2021 and stable, high quality electricity by 2030.[12] The energy demand forecast, based upon a 7 per cent GDP growth rate, estimates peak demand in Bangladesh as 17,304 MW by 2020 and 33,708 MW by 2030 (Figure 2).[6]

The Bangladesh Power Development Board (BPDB) is the largest single organization in the energy sector of Bangladesh, with 54 per cent of the country's power generating capacity while independent power producers (IPPs) generate the remainder.[6] As a single buyer, the BPDB compensates the IPPs with cost driven prices up to BDT 29.37 (US$0.382) per kWh for HFO powered electricity and up to BDT 28.24 (US$0.367) per kWh for diesel powered electricity.[9] There is no feed-in-tariff (FIT) and no regular tendering scheme in place yet for power from renewable energy. The Power Grid Company of Bangladesh Ltd (PGCB) is responsible for transmission, and BPDB, along with some government-owned companies, are responsible for distribution. BPDB charges BDT 3.33 to BDT 9.80 (US$0.043 to US$0.127) per kWh to end users depending on the type of consumer.[10]

FIGURE 2

Demand forecast in Bangladesh 2010-2030 (MW)



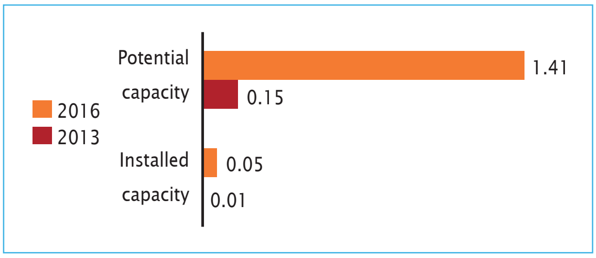
Source: BPDB[6]

Small hydropower sector overview and potential

There is no official definition of small hydropower (SHP) in Bangladesh. However, this report assumes a definition of plants with an installed capacity of below 10 MW. Current SHP capacity is 50 kW with a total identified potential of at least 1.4 MW from micro-sites alone.[6] This indicates that, despite the currently low estimated potential, approximately only 3.5 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased 400 per cent (Figure 3).

FIGURE 3

SHP capacities 2013-2016 in Bangladesh (MW)



Sources: BPDB,[6] *WSHPDR 2013*[21]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The first SHP plant was installed for demonstration purposes at a hilly region of Chittagong with a capacity of 10 kW.[19] Another SHP plant operating in Barkal Upazila of the Rangamati district has a capacity of 50 kW. An additional plant with a capacity of 50-70 kW is under development as part of an irrigation system at Mirersorai, Chittagong.[6] A number of other projects on streams in the south-east hilly regions are also under consideration for development.

Potential for SHP in Bangladesh has been explored by different organizations over the last three decades.[19] In 1981, the Bangladesh Water Development Board and BPDB jointly identified 19 prospective sites for installation of SHP plants. In 1984, a foreign consultant team identified 12 potential sites for development of mini-hydropower plants with capacities between 4 kW and 616 kW. In 2004, Local Government Engineering Department (LGED) explored seven sites, mostly located in the hilly region of Chittagong, with capacities ranging between 3 kW and 30 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. Combined, these sites suggest a potential of, at least, 1.409 MW. With exception of Chittagong hill tracts region, it is considered that micro/mini-hydro have limited potential in Bangladesh.[6] Nonetheless the Government is planning to establish a hydropower company to explore and generate hydropower potential.

SHP installed and potential capacity represents a small fraction of the current total hydropower capacity and potential. The 230 MW hydropower plant located at Karnafuli currently provides the major share of total renewable energy in Bangladesh. BPDB identified two other sites at Sangu (140 MW) and Matamuhuri (75 MW) for large hydropower plants.[6]

Renewable energy policy

Development of renewable energy is considered an important part of the Government's fuel diversification programme and a scheme to provide clean power to communities with no access to the grid. The Government has set targets to increase the share of renewable energy in the energy mix to 5 per cent (800 MW) in 2015, 10 per cent (2,000 MW) in 2021, and remain at 10 per cent (4,000 MW) in 2030.[12] To achieve this goal, the Government adopted the Renewable Energy Policy of Bangladesh (2009). National plans such as the Five Year Plan and the Power System Master Plan as well as policy documents including the National Energy Policy and Industrial Policy 2010 also emphasize the need for renewable energy. In addition, the Development of the Renewable Energy programme is part of the overall Bangladesh Climate Change Strategy and Action Plan. Renewable energy options are also included in the Bangladesh National Building Code.[14]

Bangladesh became one of the initial members of the International Renewable Energy Agency (IRENA).

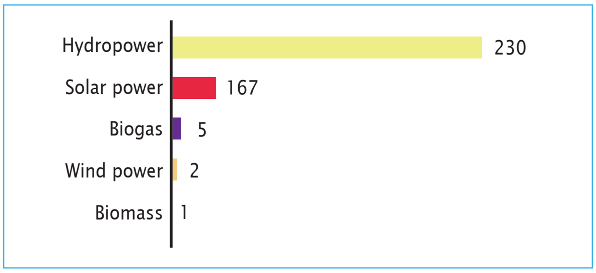
The Government has established the Sustainable and Renewable Energy Development Authority (SREDA) to promote renewable energy and energy efficiency.

Favourable taxes and duties have been imposed on renewable energy equipment in Bangladesh. A legal obligation to install photovoltaic (PV) power systems on new buildings has been imposed in order to be entitled for grid connection. The Bangladesh Electricity Regulatory Commission (BERC) has prepared draft regulations for the implementation of feed-in tariffs (FITs) for renewable energy projects in order to boost the confidence among investors.[15] The Government has allocated BDT 40 billion (US$520 million) to develop 800 MW of capacity from renewable energy sources within the fiscal year 2014-2015.[16]

The installed renewable energy capacity in Bangladesh in October 2015 was 411 MW from hydropower, solar PV, wind power, municipal waste, bio-gas, biomass, and waste residues from industrial processes (Figure 4). Solar PV is considered to have the greatest potential, while biomass and biogas are considered to have the least potential.[17]

FIGURE 4

Renewable energy in Bangladesh by source (MW)



Source: SREDA[17]

A number of commercial projects such as solar irrigation, solar mini-grids, solar parks and solar rooftop applications have been implemented by the Government and private companies. Approximately 3 million homes in Bangladesh, with aggregated capacity of approximately 135 MW are now powered by solar home systems (SHS).[18] A programme to generate 500 MW of solar-based electricity has been initiated by BPDB.[6] The potential of wind energy in Bangladesh is limited to coastal areas, off-shore islands, riversides and other inland open areas with strong winds. Two pilot wind-power plants with total installed capacity of 1.9 MW have been installed. A project to install a number of wind power plants across the coastal regions of Bangladesh with a total installed capacity of 15 MW is now underway.[6]

Legislation on small hydropower

Environmental impact assessments (EIA) are mandatory for site selection and construction of any hydropower plant that requires the construction of a dam or any other type of obstacle.

Barriers to development of small hydropower

High installation costs, lack of quality control, limited knowledge on renewable energy potential, unavailability of land and extreme weather events are the major barriers to renewable energy development in Bangladesh. Key barriers specific to SHP development include:

- A lack of studies on the potential of SHP;
- A heavily subsidized power sector which discourages the private sector to invest;
- A high population density of approximately 1,037 people per km^2 means the availability of land for SHP development is very limited;
- High initial capital costs and difficulties in obtaining loans for hydropower investment;
- A lack of interest in renewable energy, particularly hydropower technologies;
- A flat terrain limiting hydropower potential.[19,20]

3.3.3 Bhutan

Sherab Jamtsho, Department of Renewable Energy

Key facts

Population	745,153[1]
Area	38,394 km^2 [1]
Climate	Bhutan has great climate diversity: alpine or tundra in the northern region, temperate in the central region and subtropical in the southern region.[2] Temperatures vary according to elevation. The capital, Thimphu, experiences temperatures ranging between 14°C and 25°C during the monsoon season (June to September) and down to –4°C in January. In the south, temperatures fluctuate within the range of 15°C to 30°C throughout the year. The central part of the country experiences a cool, temperate climate year-round. In the high mountain regions, the average temperature is 0°C and can go up to 10°C in summer.[13]
Topography	Bhutan is a mountainous country of extremely high and irregular altitudes, often having precipitous terrain. Elevation generally increases from south to north. The mountains are a series of parallel north-south ranges. The loftiest peaks, found stretching along the northern border on the Himalayan chain, include Kula Kangri (7,554 m) and Chomo Lhari (7,314 m). Great spurs extend south from the main chain along the eastern and western borders. In the rest of the country, there are mainly ranges of steep hills separated by narrow valleys.
Rain pattern	Average annual precipitation in Bhutan is 2,200 mm but varies widely across the country: from a low of 477 mm to a high of 20,761 mm. Northern Bhutan experiences only about 40 mm of annual precipitation, primarily snow. The temperate central regions have a yearly average rainfall of around 1,000 mm, whereas in some locations of the humid subtropical south, rainfall can reach up 7,800 mm.[13]
General dissipation of rivers and other water sources	The major river systems of Bhutan are the Drangme Chhu, Puna Tsang Chhu, Wang Chhu and Amo Chhu. Originating in the Himalayas, the river systems are fed by glaciers and flow south, eventually joining the Brahmaputra River basin in India.[14]

Electricity sector overview

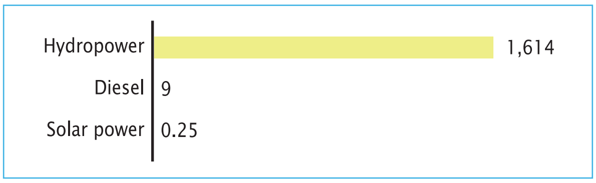
All grid-connected electricity in Bhutan is produced by hydropower plants. In off-grid areas, small stand-alone home solar systems are used.

The country's total electricity generating capacity is 1,623.25 MW (Figure 1).[2] The total installed capacity of hydropower plants is 1,614 MW and an additional 3,658 MW is under construction. The total hydropower potential of the country is estimated at 30,000 MW, of which 23,760 MW is techno-economically feasible.[4] The 11th Five Year Plan set a target of 10,000 MW installed hydropower capacity to be reached by 2020.[17]

Total generation of electricity in Bhutan in 2013 was 7,550.04 GWh, of which 7,549.5 GWh was from hydropower with the rest from diesel generators.[22] No data on the electricity produced from solar energy is available as of April 2016. The estimated technically feasible hydropower generation potential of the country is 118,260 GWh.[15] Thus, the country is currently using only 6 per cent of its hydropower potential. As of August 2013, 95 per cent of households in the country had access to electricity.[5,10] The Government aims to achieve 100 per cent electrification.

FIGURE 1

Installed electricity capacity in Bhutan (MW)



Source: Tokyo Electric Power Company[2]

The electricity demand in the country has been rising progressively over the years, with the demand being more outstanding recently. The peak power demand in Bhutan occurs around December-March when the weather is cold and people use room heaters in their houses. In 2014, peak load demand was 331.41 MW.[20]

However, due to the effect that seasonal variations have on river flow, the firm power generated by run-of-river plants is usually less than 20 per cent of their total installed capacity during the winter. The extent of this correlation was exemplified in 2013 when the minimum generation recorded was in the month of January, at 257.5 MW. In the same month the peak demand exceeded the generation by 13.76 MW (271.26 MW).[7] Therefore, in order to meet the seasonal power shortage during the winter, Bhutan imports electricity from India.[5] Throughout the rest of the year Bhutan exports its surplus electricity to India, which makes hydropower an important contributor to the country's economy.

Thus, out of the total electricity generated in 2014, 72.5 per cent was exported, which contributed 20 per cent to the country's revenue and 14.15 per cent to its GDP that year.[20]

Electricity tariffs are approved by Bhutan Electricity Authority (BEA) after reviewing proposals from the country's utility company, Bhutan Power Corporation (BPC) and Druk Green Power Corporation (DGPC; the generating company). The tariffs are set every three years. Table 1 shows electricity tariffs valid from October 2013 to June 2016.

TABLE 1

Electricity tariffs in Bhutan [Nu/kWh (US$/kWh)]

Tariff		Oct 2013 to Jun 2014	Jul 2014 to Jun 2015	Jul 2015 to Jun 2016
Wheeling (Nu/kWh (US$/kWh))		0.114 (0.002)	0.114 (0.002)	0.114 (0.002)
Low voltage				
Block	**kWh/month**	**Energy charges (Nu/kWh (US$/kWh))**		
I (Rural)	0-100	0	0	0
II (Others)	0-100	0.98 (0.015)	1.12 (0.017)	1.28 (0.019)
III (All)	101-300	1.86 (0.028)	2.13 (0.032)	2.45 (0.037)
III (All)	Above 300	2.46 (0.037)	2.82 (0.042)	3.23 (0.049)
Low bulk voltage		2.56 (0.039)	3.07 (0.046)	3.68 (0.055)
Medium voltage (6.6 kV/11 kV/33 kV)				
Energy charges (Nu/kWh (US$/kWh))		1.98 (0.030)	2.19 (0.033)	2.43 (0.037)
Demand charges (Nu/kWh/month (US$/kWh/month))		155 (2.33)	195 (2.93)	235 (3.53)
High voltage (66 kV and above)				
Energy charges (Nu/kWh (US$/kWh))		1.67 (0.025)	1.81 (0.027)	1.96 (0.029)
Demand charges (Nu/kWh/month (US$/kWh/month))		130 (1.96)	155 (2.33)	180 (2.71)

Source: Bhutan Electricity Authority[18]

Electricity prices in Bhutan have been gradually increasing in the recent years, making renewable energy more economically attractive.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Bhutan allows for an installed capacity of up to 25 MW. SHP is further classified as is shown in Table 2.

Because of the sharp differences in elevation from south to north, there are many torrential rivers, flowing from north to south (Map 1). This creates a good potential for SHP development in the country. Previously the potential was reported at 49 MW; currently there are further studies being undertaken, and as of publishing, the data is not yet available.[21] However, based on the present installed capacity and the capacity of planned projects and discovered sites, it is possible to conclude that the potential is at least 93 MW.

TABLE 2

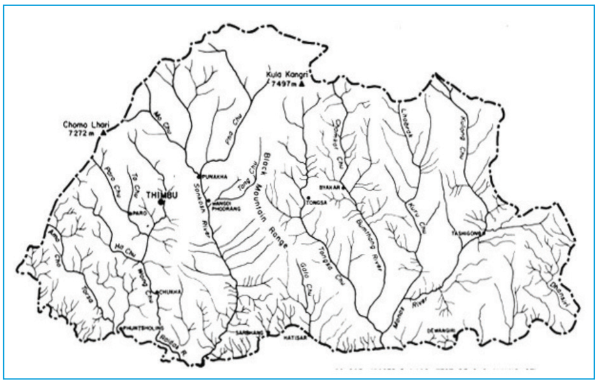
Classification of SHP in Bhutan

Type of SHP	Installed capacity
Pico	up to 10 kW
Micro	10 kW-100 kW
Mini	100 kW-1 MW
Small	1 MW-25 MW

Source: Department of Renewable Energy, Bhutan[9]

FIGURE 2

River system of Bhutan



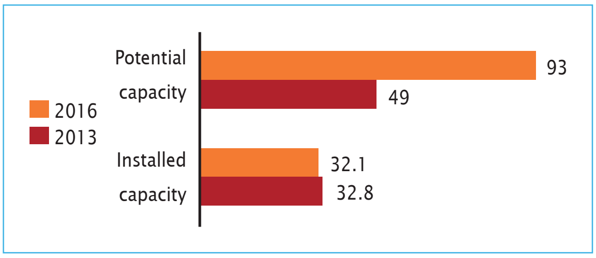
Source: Tokyo Electric Power Company[2]

Bhutan has 18 mini and micro hydropower plants with a total installed capacity of 3.14 MW, 16 of which are managed by Bhutan Power Corporation and two of which are community managed.[16] There are also four SHP plants (1 MW-25 MW): Chumey (1.5 MW), Gidakom (1.25 MW), Rangjung (2.2 MW) and Basochhu-I (24 MW) with a combined installed capacity of 28.95 MW. Thus, the total installed SHP capacity in Bhutan is 32.09 MW (Figure 3).

The Department of Renewable Energy (DRE) under the Ministry of Economic Affairs acts as the nodal agency for the promotion of SHP. By 2025, it is planned to build an SHP plant with an additional installed capacity of 5 MW. Another four sites have been studied for construction of SHP plants ranging from 14 MW to 24 MW.

FIGURE 3

SHP capacities 2013-2016 in Bhutan (MW)



Sources: *WSHPDR 2013*,[11] Bhutan Power Corporation[16]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

For those places where grid connection has reached, the Bhutan Power Corporation is planning to rehabilitate some of the SHP plants to new locations as per the survey carried out by JICA.[2]

At the moment rural Bhutan is provided with time-bound free power for social reasons and in an attempt to reduce firewood consumption. This in turn is expected to reduce deforestation and reinforce catchment areas for sustainable hydropower generation.[19]

For further development of SHP, Bhutan is considering public-private partnerships (PPP).[5] Lastly, in order to encourage private sector participation in SHP and renewable energy in general, the DRE is developing a feed-in tariff (FIT) for renewable energy resources including SHP plants.

Renewable energy policy

The 2013 Alternate Renewable Energy Policy (AREP) is the guiding policy to promote renewable energy in Bhutan, including the development of SHP plants.[9] It states that:

- The SHP projects up to 25 MW shall be allocated by DRE on open competitive bidding to the project developer following the bidding guidelines, rules and regulations prescribed by the nodal agency
- All projects for electricity generation (except for mini, micro and small hydro) shall be developed under BOO (Build, Own, Operate) model
- The SHP projects up to 25 MW, under the Renewable Energy Master Plan, shall be allocated on the basis of open competitive bidding to the project developer following the bidding guidelines, rules and regulations prescribed by the national authority
- For domestic off-take projects, the bidding shall be based on lowest tariff offered by the bidder while for export oriented projects, the bidding shall be based on the highest royalty energy being offered
- The micro, mini and small hydro projects shall be developed under Build-Own-Operate-Transfer (BOOT) model. The project shall be allotted to a developer for a concession period of up to thirty years, excluding the construction period
- Other than export oriented SHP projects, the developers of renewable energy projects shall not be required to provide royalty energy

Barriers to small hydropower development

Bhutan has a high SHP potential. However, the country's energy sector has paid more attention to developing large hydropower. In recent years, seeing the need for energy diversification, a separate department for renewable energy has been created. Since adoption of AREP, dedicated efforts have been made to promote SHP plants.

One of the biggest barriers to SHP development in Bhutan is the cost ineffectiveness of SHP electricity compared with the electricity from large hydropower. Therefore, unless the cost of developing SHP goes down; or electricity prices rise; or some financial mechanisms such as feed-in tariffs (FITs) are introduced, SHP may not be sustainable in the country.

Nevertheless, Bhutan is in the process of developing FITs for renewable energy, which will boost SHP development and create other necessary conditions to enable SHP developers to compete in the energy market.

Finally, Bhutan is prone to earthquakes and landslides; therefore, planning hydropower development and related infrastructure requires corresponding safety considerations.

3.3.4 India

Arun Kumar, Indian Institute of Technology Roorkee

Key facts

Population	1,210,569,573[1]
Area	3,287,263 km[2]
Climate	The climate varies from tropical monsoon in the south to temperate in the north. Temperatures range from 32°C to 38°C in the valleys, while at 4,500 m, the temperatures are typically below 0°C.[2]
Topography	An upland plain (Deccan Plateau) occupies the south of India, while flat to rolling plains are found along the Ganges River. Deserts take up most of the west and the Himalayas in the north, with the highest point at Kanchenjunga (8,598 m).[2]
Rain pattern	The average annual rainfall is 1,074 mm. The monsoon season is June to September, when the south-west monsoon brings 70 to 95 per cent of annual rainfall.[3]
General dissipation of rivers and other water sources	The Himalayan rivers are snow-fed and maintain a high to medium rate of flow throughout the year. During the monsoon months, the catchment areas are prone to flooding. The Ganges River basin, the largest of the country's basins, takes up approximately 25 per cent of the nation's area and extends 2,510 km. The Brahmaputra has the greatest volume of water of all the rivers in India because of heavy annual rainfall levels.[2,3]

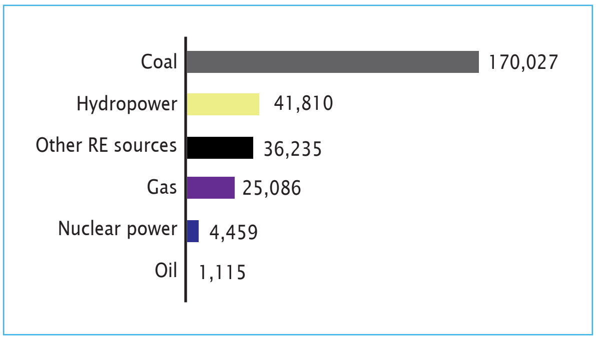
Electricity sector overview

The total installed capacity of the country was 278,733 MW as of 30 September 2015. The breakdown of the total installed capacity from different energy sources is shown in Figure 1. Renewable energy (RE) includes small hydropower (SHP), biomass, urban and industrial waste-to energy and wind energy. The power generation infrastructure is owned by the central and state governments as well as by the private sector.[1]

The Central (Federal) Government and the state governments have responsibility to promote the electricity sector and the authority to make necessary laws and regulations and to formulate and implement policies and development programmes. Indian states function under the guidance of the Central Government.

FIGURE 1

Installed electricity capacity in India (MW)



Source: Ministry of Power[1]

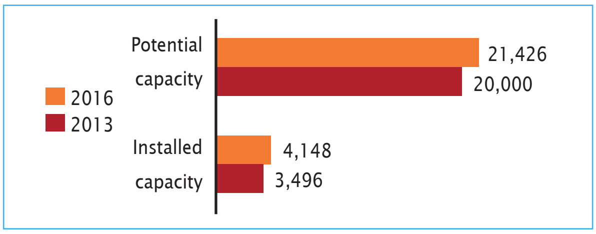
The electrification rate in India is approximately 78 per cent, so the main goal for the development of the electricity sector is to increase the availability of electricity, as well as the reconstruction of current electricity generating units. The main steps are to promote investment in electricity sector by using subsidies and tax benefits, as well as promoting renewable energy. The average electricity price in India is approximately US$0.07.

Small hydropower sector overview and potential

The definition of SHP in India is up to 25 MW. Installed capacity of SHP is 4,148 MW, while the total potential is estimated to be 21,426 MW, indicating that only 19 per cent has been developed.[5] Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 18 per cent (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in India (MW)



Sources: *WSHPDR 2013*,[6] Ministry of New and Renewable energy[5]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

TABLE 1

Classification of SHP in India (kW)

Category	Station capacity (kW)
Pico/watermill	Up to 5
Micro	Up to 100
Mini	101-2,000
Small	2,001-25,000

Source: Ministry of Power[1]

The details on potential and installed SHP capacity per state are provided in Table 2. As of April 2016, there were 1,047 SHP plants in India with the aggregated installed capacity of 4,148 MW (< 25 MW).

In India the potential of SHP development (below 25 MW) is estimated at 21,426 MW. As of April 2016, 7,239 small scale sites with 21,426 MW aggregated SHP potential have been identified in the country. As of September 2014, 4,143 identified sites (of 15,151 MW capacity or 76.7 per cent of the total SHP potential) were located on small streams (run-of-river), 379 sites (of 1,645 MW capacity, 8.3 per cent of the total SHP potential) were located on

TABLE 2

Status of hydropower development in India (as of February 2016)

Sl. no.	State	Identified potential		Commissioned		Under implementation	
		Nos.	Total capacity (MW)	Nos.	Capacity (MW)	Nos.	Total capacity (MW)
1	Andhra Pradesh	455	515	70	232	18	62
2	Telangana	—	—	—	—	—	—
3	Arunachal Pradesh	849	2,110	152	105	139	799
4	Assam	106	202	6	34	3	12
5	Bihar	148	536	29	71	16	35
6	Chattisgarh	200	1,099	9	52	70	678
7	Goa	6	5	1	0	1	0
8	Gujarat	292	202	6	17	—	—
9	Haryana	33	107	9	74	2	3
10	Himachal Pradesh	1,084	3,640	176	755	70	367
11	Jammu and Kashmir	302	1,707	39	157	16	16
12	Jharkhand	121	228	6	4	8	35
13	Karnataka	618	3,726	161	1,178	48	373
14	Kerala	239	652	27	169	14	66
15	Madhya Pradesh	299	820	11	86	3	5
16	Maharashtra	274	794	60	337	23	91
17	Manipur	110	100	8	5	3	3
18	Meghalaya	97	230	4	31	3	2
19	Mizoram	72	169	18	36	1	1
20	Nagaland	98	182	11	30	3	3
21	Orissa	220	286	10	65	4	4
22	Punjab	375	578	48	157	12	21
23	Rajasthan	64	52	10	24	—	—
24	Sikkim	88	267	17	52	1	0
25	Tamil Nadu	191	604	21	123	—	—
26	Tripura	13	47	3	16	—	—
27	Uttar Pradesh	251	461	9	25	1	2
28	Uttarakhand	448	1,708	101	209	50	214
29	West Bengal	179	392	24	99	17	84
30	A and N Islands	7	7	1	5	0	0
Total		**7,239**	**21,426**	**1,047**	**4,148**	**526**	**2,876**

Source: Ministry of New and Renewable Energy[5] the toe of existing irrigation dams, and 1,952 sites (of 2,953 MW capacity, 15 per cent of the total SHP potential) were located on existing canals, falls and barrages.[4]

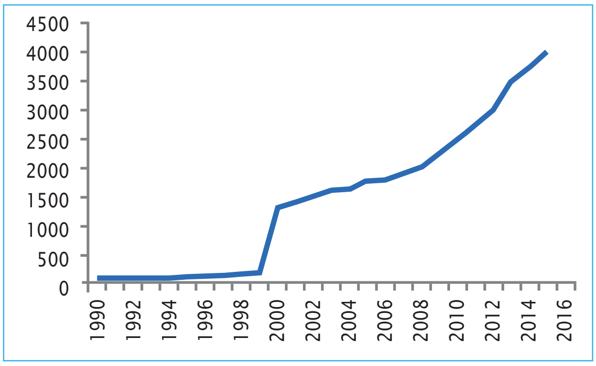
Efforts are underway for potential assessment on facilities' pipelines for drinking water and industrial use, effluent outfall at water treatment plants and sewage treatment plants, outlets of small dams and hydro kinetics in flowing channels/streams. Due to availability of suitable turbines, ultra-low head (below 3 m) potential is also being investigated and explored. A few installations on ultra-low head sites on irrigation canals and waste water outlets were commissioned recently. In the deregulated environment, small-scale pumped storage plants are being contemplated in the future.

The Indian Ministry of New and Renewable Energy (MNRE), in charge of small-scale hydro up to 25 MW, is contemplating SHP missions for the next seven years to exploit 1,000 MW of SHP capacity. Today, the SHP programme is essentially driven by private investment. The focus of the programme is to lower the cost of construction, to increase its reliability and to 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, about 800 MW have been developed on these existing facilities and are the first choice for the development by IPPs. Annual capacity of SHP projects is shown in Figure 3.

FIGURE 3

Annual capacity of SHP in India (MW)



Source: Ministry of New and Renewable Energy[5]

To make SHP cost effective and reliable, 27 documents (standards/guidelines/manuals) covering the entire range of SHP activities have been developed by the AHEC, Indian Institute of Technology (IIT) Roorkee with the support from MNRE through a consultative process and are available for the use of developers, manufactures, consultants, regulators and others.

Cost of SHP projects commissioned during recent years in India have been compiled and analysed.[8] The capital costs of the projects have gone up from INR 50 million/MW (US$0.7 million/MW) to INR 100 million/MW (US$1.5 million/MW) from 2005 to 2015 respectively.

Renewable energy policy

In August 1998 and afterwards in November 2008, the Government of India announced a Policy on Hydro Power Development. People adversely affected by hydropower have been made long term beneficiary stakeholders in the hydropower projects by way of one per cent of free power on recurring basis with a matching 1 per cent support from state governments for local area development, as well as annual cash benefits, ensuring a regular stream of benefits.[1]

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 saleable energy has been allowed. The Government of India provides subsidies for the development of SHP for government, society and private sectors in different proportions depending on the location, degree of difficulty and installed capacity.

Legislation on small hydropower

Water is a subject of state governments in India, and hence hydropower development is the responsibility of state governments. The Central Government advises on the hydropower matters and plays the role of an overall river basin planner and arbitrator. The MNRE has issued guidelines to the state governments for developing policies for renewable energy development, and especially for SHP. The Indian Electricity Act 2003 has special provisions to encourage the development of renewable energy and rural electrification. A new Renewable Energy Act 2015 has been drafted by MNRE and is under consideration by the Indian Parliament.[5]

The main features of the SHP and or renewable energy policies (different in different states) of the state government are summarized below:

- Twenty-four 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 have announced policies for setting up commercial SHP projects through private sector participation. The facilities available in the states include wheeling of power produced, banking, buy-back of power and facility for third party sale.
- SHP sites of over 8,000 MW capacity have been allotted to private sector for their development.
- Power banking (a concept of utilizing the electricity from the grid by the IPP for its use from one season's rainy period to other seasons i.e. dry period) is permitted by many states for a period of few months to one year.
- Buy back of SHP is generally based on the guidelines issued by the Central Electricity Regulatory Commission (CERC), with variations given by the

respective State Electricity Regulatory Commissions (SERCs).

- Some states provide other concessions such as lease of land, exemption from electricity duty and entry tax on power generation equipment.
- Some states do not levy any water charges known as water regulatory while some levy it as a percentage of electricity tariffs.
- Some states have prescribed the minimum quantum of power produced from renewable sources, renewable purchase obligation (RPO) to be purchased by State Distribution Licensee varying from 1 to 10 per cent in incremental manners.
- Some states have imposed minimum environmental flow during lean season and monitoring is done by automatic devices, including real-time data on the web.

Barriers to small hydropower development

There are several barriers for SHP development in India that 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 waiting periods for project licenses, clearances, in obtaining permissions or finances;
- Lack of involvement of local people;
- Lack of awareness and legal tools with the state government to regulate minimum flows in the streams;
- Lack of power evacuation infrastructure;
- Lack of clarity in ownership of SHP projects, even each project's provided share in the form of water royalty, local area development, assistance;
- Local and activists consider SHP the same as large hydropower for rehabilitation and resettlement issues and thus protest without realising the very low impacts from SHP;
- Mismatch in announced policy and field offices resulting in delay in clearances and execution;
- Lack of availability of discharge data;
- Lack of availability of suitable trained and educated manpower for SHP plants planning and design.

3.3.5 Islamic Republic of Iran

Mohammad Hajilari, Pöyry Energy AG-Iran; Oxana Lopatina, International Center on Small Hydro Power

Key facts

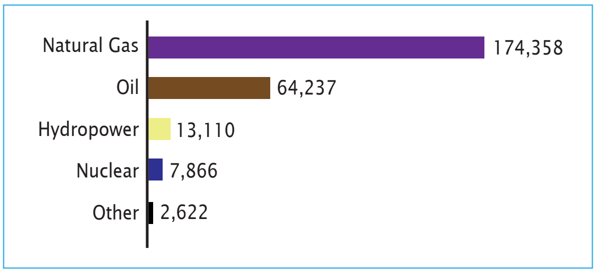
Population	78,521,605[1]
Area	1,648,195 km[2]
Climate	The climate is mostly arid or semiarid, and subtropical along the Caspian coast.[2] January is the coldest month, with temperatures from 5°C to 10°C, and August is the hottest month, at 20°C to 30°C or more. Daily temperatures can be very high; on some days temperatures can reach 40°C or higher, especially along the Persian Gulf and Oman Sea.[3]
Topography	The terrain is a rugged and mountainous rim, high in the central basin with deserts and mountains, with small, discontinuous plains along both coasts.[2] The highest point is Mount Damavand (5,610 m) and the lowest point is the Caspian Sea (-28 m).[4,2]
Rain pattern	Iran's annual average rainfall is 300 mm in the plains but only 130 mm in the desert regions.[3]
General dissipation of rivers and other water sources	There are no major rivers in the country. The only river that is navigable is the Karun River. Several other permanent rivers flow to the Persian Gulf while a number of small rivers that originate in north-west Zagros or Alborz flow to the Caspian Sea. On the Central Plateau, numerous rivers form from snow melting in the mountains during spring and flow through permanent channels, draining eventually into salt lakes. There is a permanent salt lake, Lake Urmia, in the north-west. There are also several connected salt lakes along the Iran-Afghanistan border in the province of Baluchestan va Sistan.[5]

Electricity sector overview

Installed electricity generation capacity in the Islamic Republic of Iran (Iran) was 70,279 MW in 2013, while the operational generation capacity was approximately 61,900 MW. In 2013, the electricity generation reached 262,192 GWh and the consumption of electricity in 2014 increased by 6.3 per cent and reached 218,933 GWh.[5,6]

FIGURE 1

Electricity generation in Iran (GWh)



Sources: Ministry of Energy,[6] EIA[10]

In 2013, electricity exports amounted to 11.4 billion kWh, up by 4.4 per cent compared with the year before. Imports of electricity rose by 12.5 per cent to 2.5 billion kWh. Net exports of electricity increased by 2.3 per cent compared with the previous year reaching 8.9 billion kWh.[5] In 2013 electricity was mainly generated from fossil fuels (natural gas and oil (Figure 1).[6] The first nuclear power plant in Iran is located at Bushehr, a 1,000 MW nuclear power plant which was commissioned in September 2011.

According to the *World Energy Outlook 2014*, the national electrification rate was 98 per cent. The urban electrification rate was 100 per cent while in rural areas it was 95 per cent. The population without electricity was about 1.2 million people.[7] According to Iran Grid Management (IGMC), the maximum daily electrical power generation in 2013 was 985 GWh while the maximum electrical demand was 995 GWh. Total losses in the electricity industry were approximately 15 per cent.[6] Electricity costs have been partly subsidized by the Government; generating each kilowatt hour of electricity costs IRR 680 (approximately US$0.027), while it is being sold for IRR 430 (approximately US$0.017).

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Iran is up to 10 MW. There are nine SHP plants (Table 1), with an aggregated capacity of 16.4 MW, which is approximately 0.02 per cent of the country's total hydropower generation. An additional 15.9 MW of SHP is under construction and 17.6 MW is planned. There is no clear information on the country's SHP potential capacity. However, it can be estimated by analysing projects planned and under construction, i.e. at least 49.9 MW (Figure 2).

The Government-owned Iran Water and Power Development Company (IWPCO) is responsible for hydropower development projects as well as the

TABLE 1

Installed medium and SHP

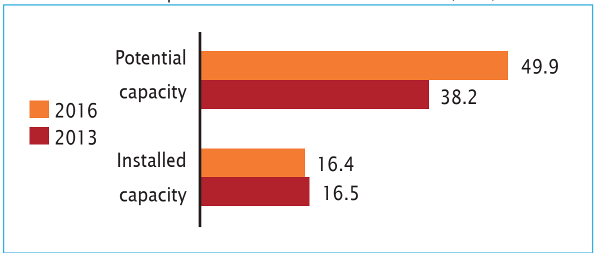
Project name	Capacity (MW)	Scale of project
Arde Power Plant	0.125	Micro
Darre Takht 1 Power Plant	0.68	Mini
Darre Takht 2 Power Plant	0.9	Mini
Gamasiab Power Plant	2.8	Small
Kuhrang Power Plant	35	Medium
Lavarak Power Plant	47	Medium
Micro Power Plant	0.227	Micro
Piran Power Plant	8.4	Small
Sarrud Power Plant	0.065	Micro
Shahid Azimi Power Plant	1	Small
Shahid Rajaee Power Plant	13.5	Medium
Shahid Talebi Power Plant	2.25	Small
Yasuj Chain Power Plants	16.8	Medium

Source: Water and Power Development Company[8]

operation and development of facilities to secure water supply. However, Iran Water Resources Management (IWRM) provides administrative support to operate water resources effectively and develop hydropower potential.

FIGURE 2

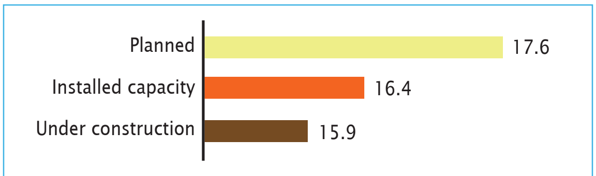
SHP capacities 2013-2016 in Iran (MW)



Sources: *WSHPDR 2013*,[11] Ministry of Energy, Iran[6]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

FIGURE 3

Overall capacity of SHP in Iran (MW)



Source: Water and Power Development Company[8]

According to the World Energy Council, the hydropower installed capacity in Iran was 9,500 MW with actual generation of 12,400 GWh in 2013.[9] IWPCO has also published a list of ready for investment small and medium hydropower projects: there are 122 sites with a total capacity of 473 MW in phase 1 study (Table 4) and 1,570 MW in pre-reconnaissance and reconnaissance phase study.[8]

TABLE 2

SHP under construction

Project name	Capacity (MW)	Scale of project
Sooleh Dokal	4.4	Small
Tarik Power Plant	3	Small
Zayanderood Regulator Dam	8.5	Small

Source: Water and Power Development Company [8]

TABLE 3

Planned medium and small hydropower plants

Project name	Capacity (MW)	Scale
Ardel Package	19.9	Medium
Dez Power Plant	20	Medium
Joobkhal	5	Small
Namarestagh Package Projects	12.6	Medium
Pichab Power Plant	4	Small
Yasouj Development	2.6	Small
Zivakeh Power Plant	6	Small

Source: Water and Power Development Company[8]

Renewable energy policy

The fifth Five-Year National Development Plan (2011 to 2016) of Iran includes renewable energy policies (wind, solar, thermo, small hydro, biomass and marine energies).

According to Section B of Article 133 of the law for the fifth Development Plan of Iran, TAVANIR and companies affiliated to the Ministry of Energy are permitted to sign guaranteed and long-term contracts for the purpose of purchasing electricity generated from renewable and clean energy sources, with a priority to purchase from private and co-operative sectors. The rate for purchase of power from renewable and clean energy sources in the competitive market of the national electricity grid takes into account the average annual avoided import or export value of the fossil fuel, the average price of energy conversion in national electricity market and the avoided cost of pollutant emission cuts approved by the Economic Council.

According to the approved direction for this regulatory article upon act N°93/22688/20/100 of 20 July 2014 of the Economic Council, the base rate for purchase of power from plants for a maximum of 5 years has been defined at IRR 4,628/kWh (US$0.15) (cost of production and transition to 20 KV station) and IRR 4,480/kWh (US$0.14) for plants (only electricity production).[10] Currently nine medium and large hydropower sites are under continued reconnaissance study phase.

TABLE 4

Potential small and medium hydropower under Phase 1 studies in Iran

Package name	Province	No. of projects	Annual energy (GWh)	Capacity (MW)
Dez regulator dam	Khozestan	1	172	28
North 1st package	Mazandaran	6	99	17
North 2nd package	Mazandaran	4	65	31
North 3rd package	Qazvin	5	50	7
North 4th package	Mazandaran	8	117	22
North 5th package	Gilan	6	69	10
North 6th package	Gilan	6	134	16
Oroomieh 1st package	West Azarbayjan	10	101	38
Oroomieh 2nd package	West Azarbayjan	4	65	29
Ardabil package	Ardabil	7	65	10
Aghchay package	West Azarbayjan	8	132	31
Lorestan-Dez package	Lorestan	14	69	12
Kohgilooyeh and Boyerahmad package	Kohgilooyeh and Boyerahmad	22	342	74
Chaharmahal and Bakhtiari package	Chaharmahal and Bakhtiari	16	368	110
Kermanshah package	Kermanshah	4	26	8
Azad H.P.P.	Kordestan	1	74	30
Total		**122**	**1,948**	**473**

Source: Water and Power Development Company [8]

Legislation on small hydropower

The 1968 Iran Water Law and the Manner of Water Nationalization provides the framework for the utilization of water resources in the country. Provisions are included for licensing, duties, water charges and dues, water rights and use permits. More specifically, the Law provides for the nationalization of river basins and of other water resources, the public use of water resources, the concession of permits consenting use of water resources and the relative prescriptions.[12]

Barriers to small hydropower development

Although there has been emphasis put on developing SHP, some barriers persist:

- Limited amounts of water resources;
- Stronger focus has been put on the development of medium and large hydropower plants;
- Lack of investment, which postponed some of the projects.

3.3.6 Nepal

Madhu Prasad Bhetuwa, Ministry of Energy; Marcis Galauska and Nathan Stedman, International Center on Small Hydro Power

Key facts

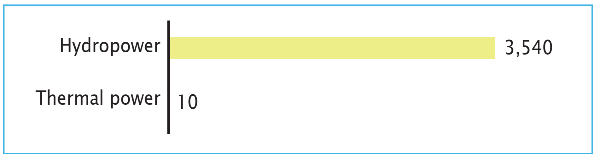
Population	28,279,480[1]
Area	147,181 km[2]
Climate	Influenced by maritime and continental factors, Nepal's climate has four distinct seasons. Spring (March to May) is warm, with rain showers and temperatures around 22°C. Summer (June to August) is the monsoon season, with temperatures up to 30°C. Autumn (September to November) is cool, with clear skies and 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.[2]
Topography	Nepal is made up of three strikingly contrasting areas. Southern Nepal has much of the character of the great plains of India known as the Terai. The second and by far the largest part of Nepal is formed by the Mahabharat, Churia and Himalayan mountain ranges, extending from east to west. The third area is a high central region, some 890 km between the main Himalayan and Mahabharat ranges. This region is known as the Kathmandu Valley, or the Valley of Nepal. The highest peak is Mount Everest (Sagarmatha), at 8,800 m.[3]
Rain pattern	The mean annual rainfall in Nepal ranges from 250 mm (in north-central, near the Tibetan plateau) to above 5,000 mm (southern slopes of the Annapurna Range in central Nepal). About 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 m. Snow contribution to precipitation is around 10 per cent of total rainfall.[2]
General dissipation of rivers and other water sources	There are about 6,000 rivers in Nepal with a catchment area of 1,94,471 km², of which 74 per cent lies in Nepal. The rivers can be broadly divided into three categories, according to their origins. The first category comprises the four main river systems of the country—the Koshi, Gandaki, Karnaliand and Mahakali river systems, all of them originating from glaciers and snow-fed lakes. They are perennial rivers with significant flow even during dry season. Rivers originating from the Mahabharat Range or midlands like Babai, West Rapti, Bagmati, Kamala, Kankai and Mechi are fed by precipitation and groundwater. These rivers are perennial but with little flow during the low 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 high potential for hydropower development.[3]

Electricity sector overview

Overall electricity generation in 2014 was 3,550 GWh, while an additional 1,072 GWh was imported from India. Electricity was predominantly generated by hydropower plants (3,540 GWh) while thermal accounted for approximately 10 GWh (Figure 1). Overall installed capacity was 787 MW with approximately 93 per cent of installed capacity from hydro. 782.5 MW were connected to the electricity grid while 4.5 MW were isolated. Peak load in 2014/15 was 6,509 GWh, indicating a significant shortage of electricity.[4]

Ten years of civil war has left its mark on the electricity sector—the overall electrification rate is approximately 70 per cent (93 per cent urban, 49 per cent rural). However, the majority of rural areas are still lacking access to electricity sources partially due to geographical restrictions and dispersion of population.[13] The 2015 earthquake which devastated much of the country also had a severe impact on the electricity network, causing losses of 150 MW of capacity and reducing NEA's output to 564 MW.[12]

FIGURE 1
Electricity generation in Nepal (GWh)



Source: NEA[4]

The Nepal Electricity Authority (NEA), a wholly government-owned corporation, dominates the power sector. It is responsible for most of the country's electricity generation, scheduling, dispatch, transmission, distribution and sales. It operates hydropower plants with a total installed capacity of 466 MW (with 15 projects more than 1 MW), two diesel plants with total installed capacity of 53 MW, and two small 0.005 MW solar power facilities. NEA and its subsidiary companies are constructing 11 hydropower projects (914.3 MW).

There has been private sector participation in the Nepalese power sector since 1992, under the Hydropower Development Policy of the same year. So far, 32 independent power producers (IPPs) contribute 270.92 MW of generation capacity. Further, IPPs are executing 89 HEPs with total installed capacity of 1,456.35 MW.[5]

About 107 km of transmission lines are privately owned. One large privately-owned distribution company, Butwal Power Company, supplies electricity to 23,000 consumers, and there are many community-managed distribution schemes scattered across the country.[5]

Nepal views hydropower development as a key opportunity for economic growth and human development; to overcome the imbalance of supply over demand, as well to keep pace with the growth in annual demand, Nepal Electricity Authority is undertaking the construction of a number of hydropower projects. Quite a few projects are also being developed through NEA's subsidiary and associate companies. Extension of the transmission grid and the distribution network are also NEA's responsibilities.[4]

Recently, after signing a Power Trade Agreement with India, the Integrated Transmission Master Plan is being prepared regarding projects that will be implemented by 2035 by the Joint Technical Team of Nepal and India.[4]

Small hydropower sector overview and potential

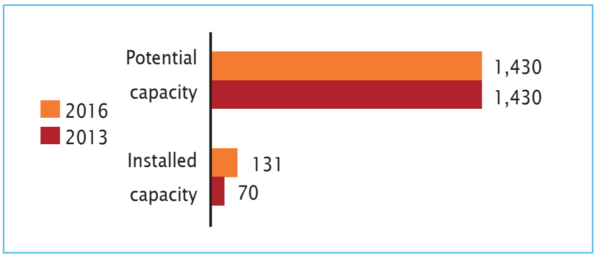
Nepal adheres to the generally accepted small hydropower (SHP) definition of up to 10 MW capacities, though it is not clearly defined in government policy or legal documents. Installed capacity of SHP in Nepal is 131 MW.[14] Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 87 per cent while estimated potential has not changed (Figure 2).[8,14]

At least 97 MW of SHP plants are privately owned while 25 MW are owned by the Government. For projects under construction as of 2014, 1.8 MW of were being developed by Nepal Electricity Authority (NEA), while 159 MW by private investors.[4,8]

For rural communities the development of small off-grid hydropower plants is a key priority. Supported by UNDP, the Rural Energy Development Program is seeking to promote renewable energy sources by building SHP and solar heating (cooking stoves) systems to provide reliable, low-cost electricity to a large number of isolated, rural communities. Launched in 1996 as a small pilot initiative in five remote hill districts, the programme was subsequently scaled up via the national Hydropower Development Policy of 2001, which focused on rural development via low-cost hydropower systems. The lessons learned from this programme helped formulate the National Rural Energy Policy in 2006 and subsequent national five-year plans.[8] In partnership with the Government of Nepal and Australian Aid, UNDP's Microenterprise Development Program (MEDEP) helped over 11,965 households gain access to electricity through 37 micro hydropower plants (MHP) in 2013.[7]

FIGURE 2

SHP capacities 2013-2016 in Nepal (MW)



Sources: *WSHPDR 2013*,[8] NEA,[4] IRENA[14]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

As of early 2015, over 3,000 micro-hydro schemes have brought electricity to more than 350,000 people in remote areas of Nepal, adding a cumulative 32 MW of installed capacity (reports of total capacity and quantity of MHP vary, between 25 and 52 MW). In 2014 alone, some 6.1 MW of new micro-hydro plants were installed, bringing electricity access to 150,000 people.[11]

In the case of independent power plants, a project company is created (also called special purpose vehicle or SPV), and this company is responsible for recovering the investment cost: the revenues from sale of electricity generated by the project are then used to recover both capital and operational costs. In practice a share of the investment is then financed by public or private investors in the form of equity, which they invest as shares in the project company. The remaining amount required for the investment is contracted by the project company in form of debt towards banks or a public institution. Debt will be repaid over the loan period with an interest rate. For hydro projects with long-term sales agreement, the leverage is usually 60 to 70 per cent but can reach 75 to 80 per cent. For capital-intensive projects, the cost of debt is paramount. Interest rates tend to be higher the riskier the project looks. This is sometimes offset by subsidies from public institutions, especially when a project can serve public interests (like rural electrification).[9]

The earthquake in April 2015, which claimed more than 4,000 lives, also gravely affected the electricity system of the country. At least 150 MW of installed capacity was damaged. In any case, complete data for small, mini and micro hydro plants damaged in the disaster is not yet available. Due to the nature of the earthquake and the landslides it caused in the mountainous regions where many mini and micro sites are located, it can be assumed that the damage was significant. Table 1 illustrates the damage to hydropower plants from 1 MW to 10 MW, as reported so far (45 MW in total).[12]

TABLE 1
SHP damage by 2015 earthquake in Nepal

Site name	MW	Damage and status
Sunkoshi Khola	2.50	Power house damaged; landslide at penstock.
Indrawati-III	7.50	Damaged but operational
Chaku Khola	3.00	Damaged, non-operational
Baramchi Khola	4.20	Damaged penstock, operational
Middle Chaku	1.80	Damaged, non-operational
Sipring Khola	9.65	Landslide at penstock, non-operational
Ankhu Khola – I	8.40	Landslide damage to sub-station and power house, non-operational
Mailung Khola	5.00	Damage to headworks, penstock and power house, non-operational
Bhairab Kunda	3.00	Damage to tunnel, penstock, switchyard and transmission line, non-operational

Source: Nepal Energy Forum[12]

Legislation on small hydropower

The Electricity Act (1992) waives the licensing requirement for hydropower projects of below 1 MW capacity, provided the project is registered with the District Water Resources Committee and forwarded to the Department of Electricity Development (DoED).[13]

The Hydropower Development Policy (2001) aims to provide rural and countrywide electricity access through affordable and efficient hydroelectric power. Rural development is seen as a two-pronged objective, electrification and local economy stimulation via installing SHP plants at the local level to boost agricultural and industrial production.[13]

Renewable energy policy

In September 2011, the Government of Nepal put forward its Renewable Energy Program for 2012-2017; the main objectives were:

- Additional financing leveraged with other development partners and private sector equity to achieve the Government's goals in scaling up energy access, both on-grid and off-grid, through renewable energy sources;
- Mainstreaming commercial lending through financial institutions for renewable energy projects;
- Environmental, social and gender co-benefits such as reduction of GHG emissions, mitigation of damage to forest cover, productive end-use of energy, extended hours for domestic work and children's education, improved access to information and empowerment of local communities, particularly women;
- Rationalized fund delivery for mini and micro energy projects through a single channel (the proposed Central Renewable Energy Fund) with different windows for disbursing credit, subsidies and technical assistance;
- Transition of Alternative Energy Promotion Centre into Alternative Energy Promotion Board, which will serve as a one-stop shop for renewable energy development in the country for projects up to 10 MW in capacity.[10]

The overall target objective for SHP is 50 MW; mini and micro hydropower, 30 MW; solar home systems, 500,000 units; biogas (domestic) 140,000 plants; biogas (institutional) 10,000 plants.[10]

Barriers to small hydropower development

While there has been extensive growth of SHP in Nepal over the past 50 years, there remain several limiting factors to development. Some of the principal barriers include:

- Lack of clear and supportive policies and regulatory framework;
- Limitations on bank financing: unattractive loan duration and interest as banks are unable to raise long-term borrowings; inability to hedge the exchange risk, as lending is in US$ but the income stream is in Nepalese Rupee (NPR);
- Ineffective licensing procedures;
- No single agency fully empowered to serve the SHP sector;
- Poor or no access infrastructure or power evacuation lines;
- Burdensome environmental impact assessment;
- 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 SHPs due to take-or-pay PPAs;
- Non-availability of equity and mezzanine financing for project developers;
- Legal enforcement authorities and contracts;
- Low load factors of SHPs and their inability to deliver energy during the periods of power shortages;
- Suboptimal exploitation of hydropower sites due to ad hoc development resulting from the absence of integrated river basin plans. Financing for SHP poses one of the most critical risks for development and scale-up of SHP in Nepal.[10]

3.3.7 Pakistan

Ejaz Hussain Butt, SMEC-EGC

Key facts

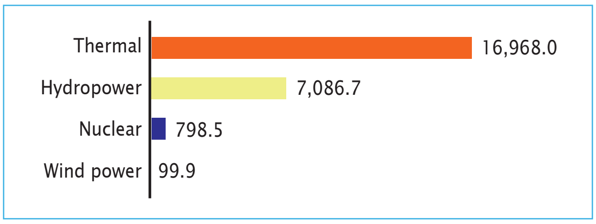
Population	188,020,00[1]
Area	803,940 km[2]
Climate	The climate is dry and hot near the coast, and progressively cooler towards the north-eastern highlands. In Islamabad the hot season begins in March and by June temperatures may reach up to 46°C, while the cold season lasts from December to February, during which the temperature may drop below −3°C. In the northernmost parts of the country winter temperatures may fall below −10°C.[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 m) and Nanga Parbat (8,126 m), are located in uppermost northern parts of Pakistan.[3]
Rain pattern	The distribution of rainfall in Pakistan varies widely, mostly associated with monsoon winds and the western disturbances, but rainfall is not continuous throughout the year.[3] Between June and September the monsoon provides an average rainfall of 38 mm in the river basins and up to about 150 mm in the north. Rainfall varies year to year. High volumes can cause floods while in desert areas low rainfall can cause droughts.[4]
General dissipation of rivers and other water sources	Surface water resources in Pakistan are mainly based on the flows of the Indus River and its tributaries. The Indus River has a total length of 2,900 km, with a drainage basin of approximately 966,000 km^2. Its main tributaries are the Jhelum, Chenab, Ravi, Beas and Sutlej. The majority of groundwater resources is concentrated in the Indus Plain, extending from the Himalayan foothills to the Arabian Sea, and are stored in alluvial deposits. The plain is about 1,600 km long, covers 210,000 km^2 and has an extensive unconfined aquifer that is fast becoming the supplemental source of water for irrigation. The mean annual availability/potential of surface and groundwater is about 170,000 million m^3 and 71,000 million m^3, respectively.[5]

Electricity sector overview

In 2014 the total installed capacity was 24,953 MW with a peak demand of 20,576 MW. The annual energy sales over the year was approximately 88 GWh.[7] Approximately 63 per cent of electricity generation is from the public sector while the remaining 37 per cent comes from independent power producers (IPPs).

FIGURE 1

Installed capacity in Pakistan (MW)



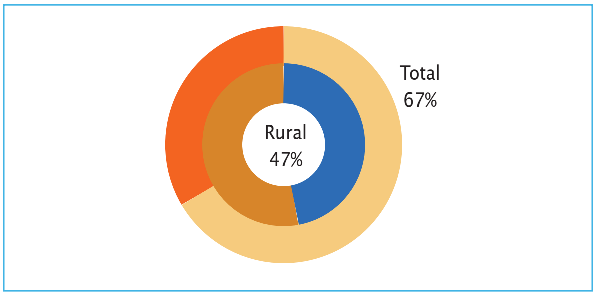
Source: NTDC (2014)[7]

Electricity in Pakistan comes from a variety of sources including hydropower, thermal, nuclear, agricultural biomass/biodiesel, solar and wind. Hydropower and thermal sources have been used for much of the country's history with plants mainly located in the northern parts of the country and a few in the plains. Together they currently account for 96.4 per cent of electricity generation in the country. Generation of electricity from solar and wind sources has recently begun, although these plants remain scarce (Figure 1).[7] According to a June 2014 report from the National Transmission and Distribution Company (NTDC), the total number of consumers was 22.5 million and the total number of villages electrified was 189,000. The electrification rate in Pakistan is approximately 67 per cent with a 47 per cent rural electrification rate. The same year, over 50,000 km of transmission lines and 765 grid stations (of various capacities) were in service.[7]

Prior to 1998, there were two vertically integrated

FIGURE 2

Electrification rate in Pakistan



Source: NTDC[7]

utilities, KESC, which served the Karachi area, and WAPDA, which served the rest of the country and was the largest public sector power generating company owning more than 59 per cent of the country's plant capacity and supplying the majority of consumers. The power sector was restructured in 1998 with the creation of PEPCO (Pakistan Electric Power Company). Today, WAPDA's power division has been structured into distinct corporate entities comprising four generation companies (GENCOs), ten distribution companies (DISCOs), one transmission company (TransCO) and the National Transmission and Distribution Company (NTDC). A small share of distribution is undertaken by Karachi Electric Supply Corporation (KESC/K-Electric).

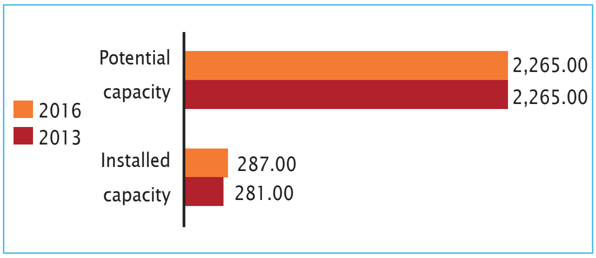
In the past, due to inadequate additions to the power pool, there was a rising power shortfall that rose to 5,000-6,000 MW during the hot season. In order to address the gap of demand and supply NTDC carried out a study for the *National Power Expansion Plan* (2011-2030). This study included plans/projects for generation, transmission, distribution and financing.[8] National Electric Power Regulatory Authority (NEPRA) is the country's sole authority to determine and fix the tariffs for all types of generating plants and the electricity consumers (domestic, commercial and industrial). Normally peak and off-peak tariffs are charged to industrial consumers. The average household electricity tariff paid in Pakistan is US$0.125/kWh.[6]

Small hydropower sector overview and potential

In Pakistan small hydropower (SHP) is defined as 50 MW or less. Installed capacity is currently 287 MW while total identified SHP potential is 2,265 MW indicating that only 12 per cent of the country's SHP capacity has been developed.

FIGURE 3

SHP capacities 2013-2016 in Pakistan (MW)



Sources: *WSHPDR 2013*,[21] Ministry of Water and Power[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The north of Pakistan is rich in hydropower resources. Numerous SHP projects have been developed and many are under implementation or have been identified with preliminary hydropower potential studies of various river basins. 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 (Tables 1, 2 and 3).

TABLE 1

Constructed/operational SHP (MW)

Province/Region	No. of SHP	Total installed capacity
Gilgit-Baltistan(GB)	102	138
Khyber Pakhtunkhwa (KPK) and Federally Administered Tribal Areas (FATA)	22	94
Azad Jammu and Kashmir (AJK)	8	12
Punjab (PUN.)	5	43
Sindh (SIND)	0	—
Baluchistan (BAL)	0	—

Source: Various[9,11,12]

TABLE 2

SHP under construction (MW)

Province/Region	No. of SHP	Total capacity (MW)
Gilgit-Baltistan (GB)	25	100
Khyber Pakhtunkhwa (KPK) and FATA	2	19
Azad Jammu and Kashmir (AJK)	19	40
Punjab (PUN)	4	20
Sindh (SIND)	0	0
Baluchistan (BAL.)	0	0

Source: Various[9,11,12]

TABLE 3

SHP studied projects and identified sites (MW)

Province/Region	No. of SHP	Total capacity (MW)
Gilgit-Baltistan(GB)	131	382
Khyber Pakhtunkhwa (KPK) and FATA	69	367
Azad Jammu and Kashmir (AJK)	41	204
Punjab (PUN)	36	189
Sindh (SIND)	17	115
Baluchistan (BAL.)	2	15

Source: Various[9,11,12]

The development of SHP is being mainly undertaken by provincial departments. For micro hydropower plants (below 100 kW), the Pakistan Council of Renewable Technologies (PCRET) has so far successfully installed 538 decentralized micro hydropower plants with a total installed capacity of 8 MW. One hundred and fifty-two of these plants were installed through various Public Sector Development Programme (PSDP) schemes in remote off-grid areas while 280 were installed in collaboration with individuals or communities. The remaining 106 plants were installed in collaboration with various governmental, non-governmental and values-based organizations providing technical assistance and post-installation supervision. A total of 228 run-of-river plants with a total capacity of 3 MW have so far been installed in the north-western frontier region. These plants not only provide lighting but are also used to run small industrial units such as flour mills for wheat and maize thrashing, and cotton ginning during the day time when lighting is not required.[13]

In the north, there are a large number of natural and manageable waterfalls making the region suitable for micro-hydropower plants. The recoverable potential in micro-hydropower is estimated to be 300 MW from perennial waterfalls while the isolated population in these areas would greatly benefit from any development of this potential. The Pakistan Alternative Energy Development Board (AEDB) is actively working with the Agha Khan Rural Support Programme (AKRSP) to install 103 mini/micro hydropower plants at Chitral and other places in Gilgit Baltistan. The United Nations Development Programme Global Environment Facility (UNDP-GEF) has committed US$100 million for the Productive Use of Renewable Energy (PURE) programme which AEDB is implementing.[15]

Pakistan has signed a Memorandum of Understanding (MOU) with the Turbo Institute of Slovenia to exchange knowledge of micro hydro turbines construction as well as the refurbishment of large hydro power plants. Compared with total installed hydropower capacity in Pakistan (approximately 7,250 MW under NTDC and other areas controlled by Pakistan), SHP accounts for less than 4 per cent while estimated SHP potential is approximately 3 per cent of the total hydropower potential (estimated at 60,000 MW).[14] Approximately 12 per cent of total hydropower potential has been developed so far with approximately 4,250 MW in Khyber-Pakhtunkhwa, 1,800 MW in Punjab, 1,150 MW in Azad Jammu and Kashmir and 50 MW in Gilgit-Baltistan. Currently a number of large hydropower projects are under construction including: Tarbela Fourth Extn. (1,410 MW), Neelum-Jhelum (969 MW), Patrind (147 MW), Kayal (122 MW), and Golen Gol (106 MW). Construction of the Dasu project (Phase-I 2,160 MW out of 4,320 MW) is set to begin with funding from the World Bank. Other projects with design and tenders completed on the waiting list due to financing constraints include Bunji (7,100 MW) and Diamer-Basha (4,500 MW). The feasibility studies of many large-scale hydro projects have been completed and some are under processing.

Renewable energy policy

Pakistan began exploring its renewable energy options during the 1980s. Between 1983 and 1988 the Government invested PKR 14 million (US$220,000) in feasibility studies for solar energy and biogas production. But no significant project development has resulted from this investment to date. Although various energy policies implemented between 1985 and 2002 stressed the need for employing renewable energy resources, none provided a framework for the implementation of such projects. Renewable energy development was virtually non-existent as these policies failed to attract private sector confidence and investment. The 2002 Power Policy, currently still in place, encouraged the use of local resources including renewable energy resources. The policy aimed to develop approximately 500 MW of renewable (non-hydro) power generation by 2015 and 1,000 MW by 2020.

In 2006 AEDB introduced the Policy for Development of Renewable Energy for Power Generation. This was the first energy policy aimed specifically at the promotion of renewable energy power projects in Pakistan. The goal under this policy is for renewable energy to provide 10 per cent of the energy supply mix by 2015. The policy focuses on solar energy, wind energy and SHP projects. The policy objectives were to:

- Increase the deployment of renewable energy technologies (thereby diversifying the energy supply mix and increasing energy security);
- Promote private sector investment in renewable energy through incentives and by developing renewable energy markets;
- Develop measures to mobilize financing and facilitate the development of a domestic renewable energy manufacturing industry (thereby lowering costs, improving service, generating employment and improving local technical skills);
- Increase per capita energy consumption and social welfare, especially in remote and rural areas where poverty can be alleviated and the burden on women collecting biomass fuel can be reduced while promoting environmental protection and awareness.

The policy stimulated some interest in renewable energy project development for large-scale power generation. However, progress has been slow and only one 50 MW wind energy project has so far been completed. The reasons for the slow uptake, as well as the positive aspects of the Government's renewable energy policy, are now being considered. AEDB is in the process of updating the 2006 Alternative and Renewable Energy Policy. The Mid-Term Policy (five years) will succeed the current Short-Term Policy in 2015. The policy tools aim to boost the growth of the domestic renewable energy industry by 2015 and allow future policy direction to evolve. AEDB started the formulation process for the medium-term policy in 2007/08 and experts from the Asian Development Bank, the German Development Fund (GTZ) and the United States Agency for International Development (USAID) helped AEDB to shape the new proposed policy.[16]

The Mid-Term Policy is the logical progression from the Lenient Phase for rapid growth short-term policy established in 2006. The Mid-Term Policy is the Consolidation Phase for sustainable growth (2010 to December 2014) and the Long-Term Policy will be the

TABLE 4

Price of electricity generation from renewable energy sources in Pakistan

Source	Small hydro	Solar	Wind	Coal (local)	Coal (imported)	Gas (imported)	Nuclear**	General (Avg.) electricity price
Price per kWh (US$ cents)	8.45*	16.3*	13.5*	10.6	11.6	11.7	11.0**	12

Source: IAE[19]
Note: An asterisk (*) indicates Upfront Tariff by NEPRA. Double asterisks (**) indicate data is not country-specific.

Maturity Phase for competitive growth (January 2015 onwards).[16]

The Mid-Term Policy provides the following general incentives:

- Mandatory purchase of electricity; and
- Guaranteed grid connection.

Specific incentives for independent power producers (IPP) of alternative and renewable energy (ARE) include:

- Simplified generation licensing procedure;
- Simplified land and site access; and
- Security package: guaranteed purchase of all power and payment, facilitated acquisition of carbon credits.

Due to the significance of the renewable energy policy and its consequences on the future of the renewable energy sector, AEDB held stakeholders' consultation workshops at provincial and national levels. Stakeholders' comments and concerns are being addressed and incorporated to finalize the Mid-Term Alternative and Renewable Policy document, which will be presented to the cabinet for approval.[17]

Legislation on small hydropower

Recently the National Electric Power Regulatory Authority (NEPRA) has approved a maximum of PKR 8.32 (US$0.120) per unit, upfront tariff for SHP projects (up to 25 MW installed capacity) under Section 31 (4) of the Regulation of Generation, Transmission and Distribution of Electric Power Act 1997. According to NEPRA, comparatively small capital investment and short gestation periods are required to complete these projects and hence it also added procedural improvements to make investment easier for small investors. The upfront tariff was introduced to simplify the tariff process providing certainty to the potential investors, fast-tracking the development of commercially attractive SHP sites and allowing material risk coverage to the investor.

The economic attractiveness of the upfront tariff was further enhanced as the tariff will be adjusted for each site depending upon the plant factor. The upfront tariff will reduce project development periods considerably.[18]

The price of electricity generation from renewable energy and general electricity prices in Pakistan can be compared in Table 4.[19]

Barriers to small hydropower development

The future of SHP development in Pakistan is promising as abundant potential is available in the northern hilly areas and on canal falls and barrages in the plains. The Government has devised policies for the development of renewable energy sources that include SHP, which is the cheapest source of renewable energy.

Despite this, barriers to SHP development in Pakistan include:

- Availability of finances and continuity of supply of funds; delays sometimes cause costs to over-run;
- Involvement of a large number of institutions/ departments, thus projects take much longer to approve;
- Higher costs of the projects due to foreign components;
- Limited interest from local manufacturers to develop low cost electrical and mechanical equipment for SHP;
- Lack of government activity to develop hydropower projects with projects with shorter periods such as roads and infrastructure prioritized;
- Settlement of water rights issues on some projects;
- Risks involved with SHP projects can deter developers;
- In the upper northern areas (Gigit-Baltistan), grid connection is not available so the maximum potential of the sites cannot be developed.

3.3.8 Sri Lanka

Nuwan Premadasa and Nimashi Fernando, Sustainable Energy Authority

Key facts

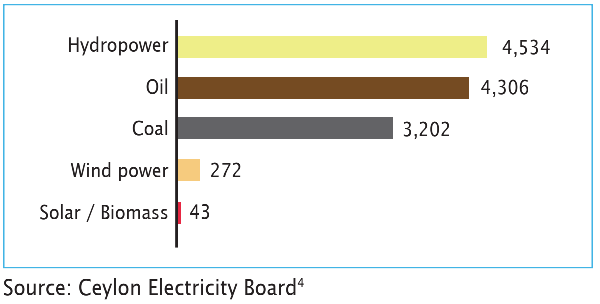
Population	22,053,488[1]
Area	65,610 km^2 [1]
Climate	The climate is tropical monsoon, with the north-east monsoon from December to March and the south-west monsoon from June to October. Temperatures do not vary widely, averaging 27°C.[1]
Topography	The terrain is mostly low, with flat to rolling plains. Coastal areas reach as low as 0 m above sea level. The country is mountainous in the south-central interior, with the highest peak, Pidurutalagala, at 2,524 m.[1]
Rain pattern	Rainfall in Sri Lanka has multiple origins. Monsoonal, convectional and expressional rain accounts for the major share of the annual rainfall. The mean annual rainfall varies from under 900 mm in the driest parts (south-east and north-west) to over 5,000 mm in the wettest parts (western slopes of the central highlands).[2]
General dissipation of rivers and other water sources	Sri Lanka has 103 distinct river basins with a total catchment area of 59,245 km^2, which accounts 90 per cent of the total land area. Most of the river basins originate from the central highlands and flow to the Indian Ocean, passing through the lowlands.[3] Among them, the Mahaweli, Kalu and Kelani Rivers have 722 MW small hydropower potential while 151 MW of capacity prevails with rest of the rivers.[6]

Electricity sector overview

The installed electricity generation capacity in Sri Lanka was 4,044 MW in 2014 while the maximum demand flagged was 2,152 MW. Gross electricity generation reached 12,357 GWh in 2014 and 70 per cent of gross generation was supplied by state owned power plants having 2,824 MW of installed capacities while 30 per cent was supplied by independent power producers (IPP) having 1,220 MW installed capacities.[4] The share of new renewable energy (NRE) in the generation mix was 9.8 per cent in 2014. Figure 1 shows the electrical energy mix of Sri Lanka in 2014. Sri Lanka, compared with other countries in the region, has a very high electrification rate, which is 98 per cent at present. The remaining 2 per cent of households are supplied with off-grid electrification options.

FIGURE 1

Electricity generation in Sri Lanka (GWh)



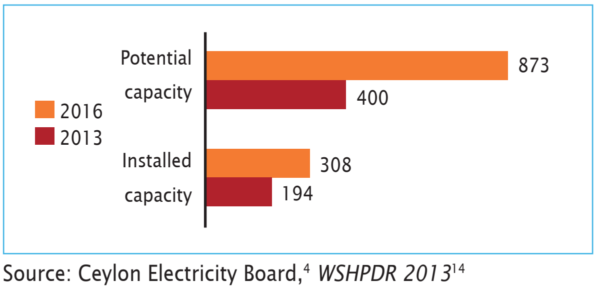
Source: Ceylon Electricity Board[4]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Sri Lanka is up to 10 MW. The installed capacity of SHP is 288 MW while the potential is estimated to be 873 MW indicating that less than 33 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 48 per cent while estimated potential has increased by approximately 118 per cent (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Sri Lanka (MW)



Source: Ceylon Electricity Board,[4] *WSHPDR 2013*[14]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Currently, there are 140 SHP plants operated by IPPs with a combined installed capacity of 288 MW.[4] In 2014, they generated 902 GWh of electricity.[13] Additionally, Ceylon Electric Board operates SHP plants that contribute 20

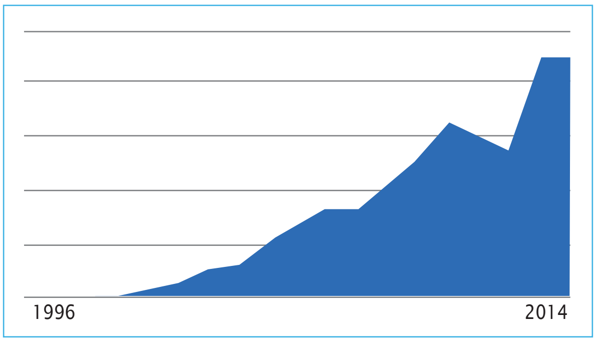
MW to the national grid and generated 31 GWh in 2014. Off-grid SHP plants generated approximately 11 GWh the same year (no data on their total installed capacity available as of April 2016).[13] The SHP sector is the most dominant new renewable energy sector which contributes a share of 75 per cent in NRE generation alone, and 7.6 per cent to the total generation of Sri Lanka.

Sri Lanka has the challenge of developing unexploited small hydro potential of 565 MW from the limited number of economically feasible potential sites as identified and gazetted by the Sri Lanka Sustainable Energy Authority (SEA). According to SEA, the total economically feasible SHP potential in Sri Lanka is 873 MW.[6]

The cumulative capacity additions from NRE resources from 1996 reflects the fact that capacity additions from NRE plants, including SHP, accelerated steadily since the establishment of SEA in 2007, which resulted in a stepped up production of SHP in the consecutive years as shown in Figure 3.

FIGURE 3

Stepped up production in IPP SHP generation in Sri Lanka, 1996-2014 (GWh)



Source: Sri Lanka Sustainable Energy Authority[5]

Electricity market prices have been determined by the Public Utilities Commission which is the economic, safety and technical regulator of the electricity sector in Sri Lanka.[7] It has introduced different tariff structures for domestic, religious and charitable institutions and non-domestic sectors, which also includes industrial tariff and general purpose tariff structures. Domestic sector tariffs range from LKR 2.50/kWh (US$0.018/kWh) to LKR 45.00/kWh (US$0.033/kWh) per month while non-domestic sector tariffs vary LKR 10.80/kWh (US$0.078/kWh) to LKR 23.50/kWh (US$0.17/kWh) depending on the time of use and supply voltage levels.[5]

Renewable energy policy

The SEA, being the prominent policy maker in the new renewable energy sector under the purview of the Ministry of Power and Energy (MPE) in Sri Lanka, has set the goal of 20 per cent electrical energy generation from new renewable energies by 2020, and foresees further increases to the share of electricity generation from renewable energy sources from 39 per cent in 2015 to 60 per cent by 2020 and finally to meet the total demand from renewable and other indigenous energy resources by 2030.[8]

A highly transparent renewable energy resource allocation procedure was introduced by the SEA to allow IPPs to contribute in achieving aforementioned targets with the 20-year renewable energy permit (EP) and the 15-year Standardized Power Purchase Agreement (SPPA); the objective is to curtail the risk of investing in small scale power projects including SHP projects with capacities up to 10 MW. Private sector developers are able to develop renewable energy resources, identified as ‘Energy Development Areas’, by the subsidiary legislation of the Sustainable Energy Authority Act (N°35 of 2007), allocated to them based on first-come-first-served principle with the blessings of the aforementioned procedure.

Legislation on small hydropower

Through the primary legislation on SHP projects in Sri Lanka, the Sustainable Energy Authority Act N°35 of 2007, which has the objectives of developing renewable energy resources, declaring energy development areas as well as promoting energy security, reliability and cost effectiveness in energy delivery and information management, SEA acts as the regulator who can regulate hydropower resources and the land requirements for projects.[9] The detailed information on the project development process is contained in a publication titled A Guide to the Project Approval Process for On-Grid Renewable Energy Project Development and is cited in the subsidiary legislation as a binding acceptance, making the guide a part of the SHP legislation.[10] The salient features of the SPPA are as below:[11,12]

- A complete avoidance of market risk: the Ceylon Electricity Board assures the purchase of all that is produced by a SHP project;
- A floor price of 90 per cent of the tariff: ensuring a steady and predictable cash-flow;
- A long-term commitment: the SPPA lasts 15 years and is based on sound legal provisions;

Sri Lanka is the first country in the region to start a 100 per cent renewable energy plan to make Sri Lanka an energy secure country by 2030 and currently a role model in developing SHP resources endowed by the natural environment.[7] The Government of Sri Lanka through SEA currently provides policy and technology support to the SHP industry for the development of SHP in the country. Currently, the leading Sri Lankan SHP businesses are very active on the African continent in consulting and project development. The country has a well-developed SHP value chain.

Barriers to small hydropower development

As Sri Lanka is rich in hydro resources, the SHP sector in Sri Lanka has reached its maturity state and competencies in project development have increased to a commendable level with the support of policy frameworks and human resources' development. However, the industry is still experiencing barriers to implementation in the following areas:

- Absence of a dedicated transmission solution for the uptake of power from SHP plants.
- Limitations at local grid sub-station levels and at the national power system level for adding more SHP to the grid.
- Public opposition at regional levels arising out of conflicting use of water resources.
- Absence of a well-equipped monitoring system for sustainability assessments of operational SHP projects.
- Unavailability of proper river modelling strategy; changing of surface-runoff characteristics such as flash floods reduces the anticipated energy benefits of the SHP projects at the preliminary project development stage.

3.4 South-Eastern Asia

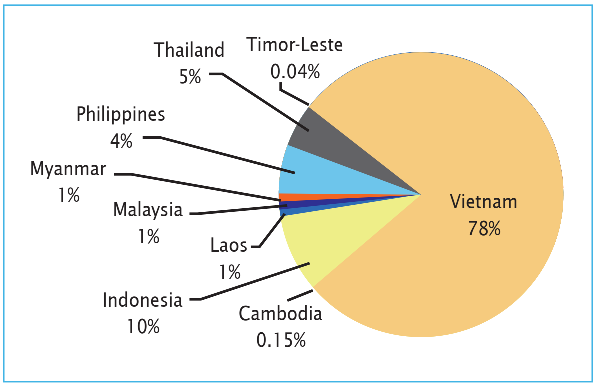
Engku Ahmad Azrulhisham, University of Kuala Lumpur

Introduction to the region

According to the United Nations definition, the South-Eastern Asia region consists of 11 countries: Brunei, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Timor-Leste Thailand and Viet Nam. The current report covers nine countries: Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Thailand, Timor-Leste and Viet Nam. The overview of countries of South-Eastern Asia is given in Table 1.

FIGURE 1

Share of regional installed capacity of SHP by country



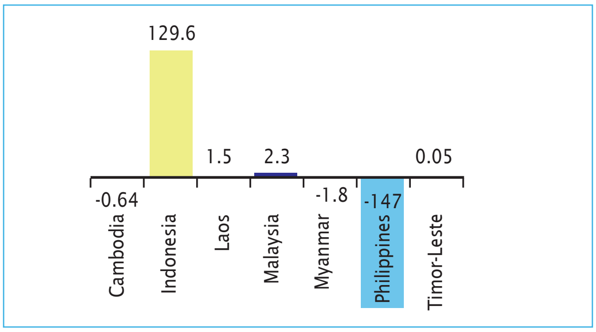
Source: *WSHPDR 2016*[1]

The countries of the region vary greatly in terms of economic, political and cultural conditions, as well as energy profile. Some countries of the region have large energy resources. For example, Indonesia and Malaysia are rich in fossil fuels. On the contrary, other countries such as Myanmar and Cambodia have relatively limited indigenous energy resources and rely on energy imports.

South-Eastern Asia is one of the most dynamic regions in the world. Ten countries in the region, united in the Association of the Southeast Asian Network (ASEAN), have seen rapid economic and demographic growth in the last 25 years, as demonstrated by the large increases in electricity generation capacities of several countries (Table 1). The only country that has yet to join the regional organization is Timor-Leste.

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for South-Eastern Asia



Sources: *WSHPDR 2016*,[1] *WSHPDR 2013*[2]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites and/or due to access to more accurate data for previous reporting. Excluding Thailand and Viet Nam due to usage of different SHP definitions between the 2013 and 2016 reports.

TABLE 1

Overview of countries in South-Eastern Asia (+ % change from 2013)

Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Cambodia	15.41 (+9%)	80 (0pp)	50 (+21pp)	1,511 (+181%)	3,058 (+31%)	929.4 (+6,888%)	1,851.6 (+3,603%)
Indonesia	254.45 (+6%)	47 (-9pp)	87 (+20pp)	51,620 (+46%)	230,000 (+29%)	6,654 (+47%)	18,320 (+67%)
Laos	6.80 (+5%)	62 (-5pp)	82 (+27pp)	3,329 (+349%)	16,000 (+930%)	3,329 (+66%)	16,000 (+60%)
Malaysia	31.05 (+9%)	26 (-2pp)	97 (-2pp)	29,748 (+29%)	141,266 (+40%)	3,931 (+106%)	11,805 (+138%)
Myanmar	53.44 (+11%)	66 (0pp)	33 (+20pp)	4,394 (+95%)	12,247 (+91%)	2,805 (+82%)	8,823 (+13%)
Philippines	106.40 (+14%)	56 (+5pp)	88 (-2pp)	17,994 (+34%)	77,261 (+31%)	3,543 (+8%)	9,137 (+42%)
Thailand	65.10 (-6%)	51 (-15pp)	99 (0pp)	38,815 (+26%)	177,775 (+28%)	3,761 (+10%)	3,761 (-29%)
Timor-Leste	1.21 (+1%)	68 (-4pp)	75 (+53pp)	256 (+469%)	348 (-)	0.35 (+17%)	1.5 (0%)
Viet Nam	90.73 (+4%)	67 (-3pp)	99 (+1pp)	34,080 (+112%)	127,028 (+31%)	15,703 (+186%)	57,131 (+138%)
Total	**624.59 (+6%)**	—	—	**181,747 (+49%)**	**784,983 (+34%)**	**40,655 (+83%)**	**126,830 (+82%)**

Sources: Various[1,2,4,5,6,7,8,9,10,12,14]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.

One of the main concerns of ASEAN countries is to provide energy security. The countries are struggling to meet the escalating energy demand of their growing populations and economies. Another concern is the need to develop energy infrastructure, particularly in the power sector. This is due to a rather low electrification rate among the countries, especially in rural areas. Of all the countries of the region, Cambodia and Myanmar have the lowest electrification rates.

About three-quarters of the region's energy demand are met with fossil fuels. Oil has the largest share in energy demand, followed by gas and coal. The region is expected to remain heavily reliant on fossil fuels in the future but with an increased share of other energy resources, particularly solar and wind. The upward trend in the region's energy demand is expected to persist over the coming decades.[3]

Small hydropower definition

The definition of small hydropower (SHP) varies among the countries of South-Eastern Asia. The upper limit ranges from 6 MW in Thailand, to up to 50 MW in Timor-Leste (Table 2). In Myanmar there is no official definition of SHP, so it has been assumed for plants up to 10 MW.

TABLE 2

Classification of SHP in South-Eastern Asia

Country	Small (MW)
Cambodia	up to 10
Indonesia	up to 10
Laos	up to 15
Malaysia	up to 10
Myanmar	up to 10
Philippines	up to 10
Thailand	up to 6
Timor-Leste	up to 50
Viet Nam	up to 30

Source: *WSHPDR 2016*[1]

Regional SHP overview and renewable energy policy

Eight countries of the nine covered in this report use SHP for electricity generation. It plays a significant role in rural electrification as well as represents part of the countries' renewable energy development strategies. The total installed capacity of SHP plants in the region is 2,340 MW, which about 17 per cent of its potential.

Vietn Nam is the regional leader in terms of installed and potential SHP capacity. It has 1,836 MW of installed SHP of up to 30 MW, whereas the total potential is estimated to be 7,200 MW. Hydropower accounts for about 45 per cent of the country's generation, and there are plans for further the development of hydropower. However, in 2013 its government started to cancel hydropower projects (planned and under construction) due to high social and environmental risks caused by poor planning and construction. As of August 2014, 418 SHP projects were removed from the country's hydroelectric development plan.

TABLE 3

Small hydropower in South-Eastern Asia (+ % change from 2013)

Country	Installed capacity (MW)	Potential capacity (MW)
Cambodia (up to 10 MW)	1.26 (-34%)	300 (0%)
Indonesia (up to 10 MW)	229 (+130%)	770 (-39%)
Laos (up to 15 MW)	12 (+14%)	2,000 (+150%)
Malaysia (up to 10 MW)	18.3 (+14%)	500 (+329%)
Myanmar (up to 10 MW)	34.18 (-5%)	196.7 (+18%)
Philippines (up to 10 MW)	101 (-59%)	1,975 (0%)
Thailand (up to 6 MW)	108 (-)	700 (0%)
Timor-Leste (up to 50 MW)	0.35 (0%)	N/A
Viet Nam (up to 30 MW)	1,836 (-)	7,200 (-)
Total	**2,340 (-)**	**13,641.7 (-)**

Sources: *WSHPDR 2016*,[1] *WSHPDR 2013*[2]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting

Cambodia has a total installed SHP capacity of 1.26 MW, which consists of three plants constructed under grant aid, and several privately-owned micro and pico-hydropower plants. An additional 48 sites with a combined capacity of 50 MW have been identified with potential for development. The Government of Cambodia aims to increase access to electricity to 100 per cent in urban areas by 2020 and up to 70 per cent in rural areas by 2030. Renewable energy development is expected to play a critical role in rural electrification. In general, it is planned that by 2020 renewable energy will account for more than a half of the country's total energy production. Finally, according to the Electricity Supply Development Plan, Cambodia aims to increase the generating capacities of both hydropower and coal power plants, as well as to decrease generation from diesel, heavy fuel oil (HFO) and energy imports.

Indonesia has an installed SHP capacity of 229 MW and a substantial potential of 770 MW. Therefore, SHP development is perceived as one of the key instruments towards increased electrification, particularly in rural areas. The country's total electrification rate is 87 per cent; however, in some provinces it can be as low as 43 per cent. Furthermore, grid-connected areas in Indonesia have suffered from power shortages due to the rapidly growing electricity demand. The government aims to achieve 92 per cent electrification by 2021 as well as to further develop its renewable energy sector. Lastly, the country has feed-in tariffs (FIT) in place for hydropower projects of up to 10 MW.

Hydropower is the most important energy resource for Laos, for all its electricity is generated by hydropower plants. The total technical hydropower potential of the country is estimated at 26,000 MW, of which SHP accounts for 2,000 MW. However, so far only 12 MW of the SHP potential has been harnessed. This is mostly due to management and financial issues as well as natural disasters. Nevertheless, a range of measures addressing the existing barriers for SHP development will be implemented by the government. Laos aims to reach a 30 per cent share of renewable energy in total energy consumption by 2025. Similar to other countries in the region, for Laos, SHP, in particular pico hydropower, has played an important role in electrification of off-grid rural areas.

Malaysia has a SHP potential of 500 MW and an installed capacity of 18.3 MW. Development of SHP in the country has been stimulated by both the Renewable Energy Act 2011 and an introduction of a FIT scheme in 2011. The country is experiencing an ever increasing energy demand, which the current power production will only be able to meet for the next few years. The country's energy strategy states that renewable energy sources should take a leading role in supplying energy reliability and security.

The current installed SHP capacity of Myanmar is approximately 34 MW. The total SHP potential is almost 200 MW, with more than 300 potential sites identified. The country has made significant progress in improving access to electricity. Compared with the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, the electrification rate has increased by 20 percentage points; however, it still remains the lowest in the region. Further progress will require developing a policy framework, in particular on hydropower.

The SHP potential of the Philippines is at 1,975 MW. The installed capacity of 101 MW accounts for only 5 per cent of this potential. However, with the new projects approved for construction and projects pending approval of a total installed capacity of 1,721 MW, 87 per cent of the country's potential will be harnessed. The government aims to accelerate the exploration and development of renewable energy resources to achieve energy self-reliance, and to reduce the country's dependence on fossil fuels. For this purpose FITs as well as fiscal incentives for renewable energy projects have been set up. One of the targets is to increase hydropower capacity by 160 per cent by 2030.

Thailand has 41 grid-connected SHP plants with a total capacity of 108 MW and an additional potential of almost 600 MW. According to the Thailand Power Development Plan 2010-2030, the country's main objectives are providing security and adequacy of power systems, along with promoting energy efficiency and renewable energy.

The hydropower potential of Timor-Leste was studied in 2003-2006 and was estimated at 235 MW; 23 sites were identified, including 16 for small and one for micro hydropower. Of these 23 sites, at least 15 can be considered viable, with a potential capacity of 187.6 MW. However, the SHP potential of the country is unknown. Of the existing three SHP plants with a combined installed capacity of 0.35 MW, two are currently not in operation due to technical issues. The country has launched a renewable energy programme that covers biogas, solar, biodiesel, hydropower and wind, and it aims at a 50 per cent share of renewable energy resources in meeting the country's energy needs. The government also plans to achieve an 80 per cent electrification rate by 2025.

Barriers to small hydropower development

Development of SHP in South-Eastern Asia is complicated by a range of issues, which include:

- High project costs due to location of SHP plants in remote areas with limited access;
- Complicated regulatory requirements, limited clarity on power purchase agreement, tariffs and taxes;
- Limited access to financing, lack or absence of subsidies or other financial incentives;
- Lack of technical knowledge and operational skills;
- Lack of political frameworks;
- Lack of standardization of procedures and technical codes;
- Lack of available data, including hydro-meteorological, topographical and geological data;
- Low awareness about SHP among decision makers as well as consumers;
- Lack of social and community acceptance of SHP projects;
- Poor coordination among national and regional governments;
- Technical challenges due to heavy rain patterns and difficult topography.

3.4.1 Cambodia

Piseth Chea and Paradis Someth, Mekong River Commission Secretariat (MRCS)

Key facts

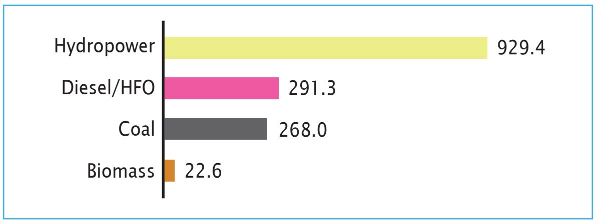
Population	15,410,000[1]
Area	181,035 km[2]
Climate	Tropical monsoon climate which gives two distinct seasons: six months of the dry season from December to May followed by six months of the rainy season from June to November. Temperatures are the hottest in April with a monthly average of 29°C (maximum 36°C) and coolest in December to January (25.6°C).[2,3]
Topography	Cambodia is physiographically characterized by four distinct topographical features. The north is formed by an escarpment of the sandstone Dangrek Mountains. The southwest is dominated by the granite Cardamom Mountains, which form a watershed boundary between the rivers flowing to the Tonle Sap Lake and the coastal area. The central flat lowland of the Tonle Sap Lake is interrupted by isolated hills. The east is dominated by mountain ranges with the highest peak being Phnom Aural at 1,810 metres above sea level.[3]
Rain pattern	The rainfall pattern of Cambodia is bi-modal 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 in the south.[3]
General dissipation of rivers and other water sources	Cambodia territory 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 about 155,000 km^2. Phnom Penh being located, at the confluence of the Mekong River and Tonle Sap River marks the beginning of the Mekong Delta. Downstream of Phnom Penh, the Mekong River splits into two: the mainstream Mekong River and the Bassac River tributary.[3]

Electricity sector overview

In 2014, the total installed capacity in Cambodia was 1,511 MW. Hydropower, diesel/heavy fuel oil (HFO) and coal plants contributed 61.5, 19.3 and 17.7 per cent, respectively. Biomass installed capacity was 23 MW, accounting for just 1.5 per cent of total capacity (Figure 1).[10]

FIGURE 1

Installed electricity capacity in Cambodia by source (MW)

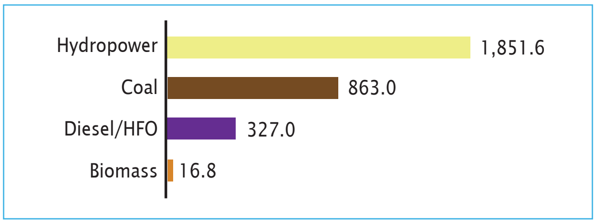


Source: Electricité du Cambodge[10]

In 2014, total domestic generation was 3,058 GWh with approximately 61 per cent provided by hydropower, 28 per cent by coal, 10 per cent by diesel/HFO and less than 1 per cent by biomass (Figure 2).[10] In order to meet demand Cambodia imported approximately 1,800 GWh (37 per cent of total consumption) from neighbouring countries such as Viet Nam, Thailand and Laos (Figure 3).[10]

FIGURE 2

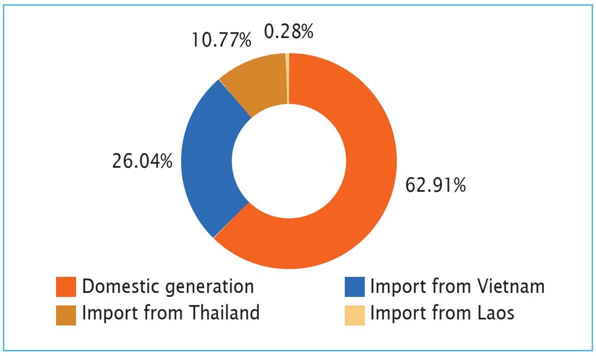
Electricity generation in Cambodia by source (GWh)



Source: Electricité du Cambodge[10]

FIGURE 3

2014 domestic and imported electricity in Cambodia by source (%)

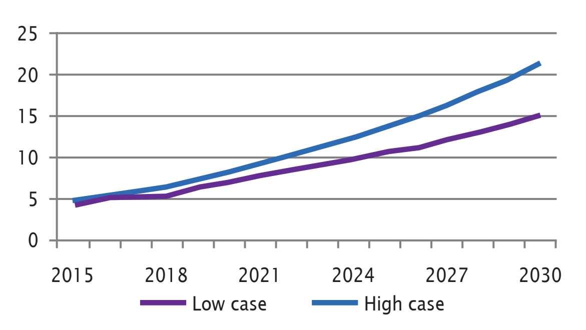


Source: Electricité du Cambodge[10]

The country's electricity demand is growing fast. Between 2009 and 2013 the average annual growth rate of electricity supply was 16 per cent, whereas energy demand was increasing by 18 per cent per year. Conservative forecasts estimate that demand could rise from 4,235 GWh in 2015 to 7,089 GWh by 2020 and 15,240 GWh (approximately 260 per cent) by 2030 (Figure 4).[10]

FIGURE 4

Energy demand forecasts in Cambodia 2015-2030 (GWh)

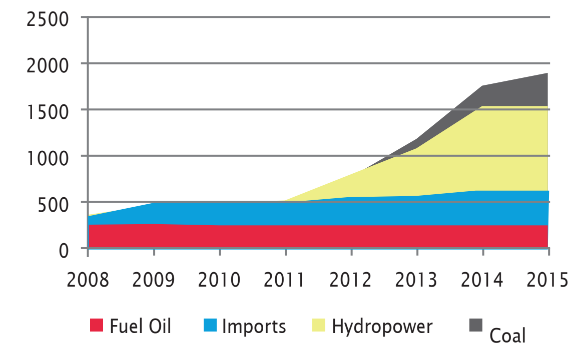


Source: Electricité du Cambodge[10]

To meet the increasing demand, the Government of Cambodia has developed the Power Development Plan (PDP) for 2008-2021. In line with the PDP, transmission lines are under construction and electricity has been imported provided from neighbouring countries to meet the increasing demand. Currently, approximately 50 per cent of Cambodian households have access to electricity with the electrification rate of 80 per cent in urban areas and of 24 per cent in rural areas. Electricité du Cambodge (EDC) aims to achieve a 100 per cent electrification rate in urban areas by 2020 and 70 per cent in rural areas by 2030. The Government also formulated the Electricity Supply Development Plan up to 2020 aiming to increase the electricity generation from hydropower and coal power plants in order to reduce generation from diesel and HFO as well as the country's dependency on imported fuels (Figure 5). According to this plan, the construction of eight hydropower plants and three coal power plants will be completed by 2020. This is expected to bring the maximum annual generation, including imported electricity, to approximately 3,576 MW.[10]

FIGURE 5

Planned expansion of electricity generation in Cambodia (MW)



Source: Electricité du Cambodge[10]

As part of the Transmission Expansion Plan, by 2020 the Government aims to construct 2,600 km of combined 500 kV, 230 kV and 115 kV transmission lines, to connect the existing grid systems (Phnom Penh city and surroundings) with planned power plants and cross-border lines to Laos.

The power sector in Cambodia is administered and managed under the Electricity Law, which was ratified in 2001. This law provides a policy framework for the development of an unbundled sector facilitating substantial private sector participation in generation and distribution on a competitive basis. The aim of the law is to establish:

- Principles for operations in the electricity generation industry and activities of electricity service providers;
- Favourable conditions for investment and commercial operations;
- The basis for the regulation of service provision;
- Protection of customers' interest to receive reliable services at reasonable cost;
- Promotion of private ownership of facilities;
- A competitive market;
- Principles for granting rights and enforcing obligations.

The Electricity Law defines the roles of the Ministry of Mines and Energy (MME) as a policy maker, the Electricity Authority of Cambodia (EAC) as a regulator and supervisor and Rural Electricity Enterprises (REEs) as electricity service providers. The 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 indigenous energy resources, planning of electricity export and import as well as subsidies to specific classes of customers. The EAC is responsible for the control and regulation of the provision of electricity services, licences for the provision of electricity power services and tariffs.

Electricité du Cambodge (EDC) is a state-owned limited liability company under the control of the MME and the Ministry of Economy and Finance (MEF) and is authorized by Royal Decree in 1996. In 2002 the EDC acquired the consolidated license from the EAC. EDC is responsible for electricity generation, transmission and distribution as well as electricity imports from and exports to neighbouring countries.[11]

EDC is the largest REEs. Other private REEs, such as Community Electricity Cambodia (CEC), are allowed to provide electricity to both the national grid and off-grid communities. With a large share of electricity imported, Cambodian electricity tariffs are among the highest in the region (Table 2). With the development of large hydropower potentials and additional coal

TABLE 1

Actual and planned electricity tariffs in Cambodia 2010 – 2020

Tariff type	Tariff (US$ per kWh)						
	2010	2015	2016	2017	2018	2019	2020
Industrial and commercial customers							
Purchase from GS	0.122	0.129	0.126				
Purchase from National Grid	0.179-0.229	0.177	0.172	0.167	0.165	0.163	0.162
Purchase from Provincial Grid	0.172	0.167	0.165	0.165			
Residential							
Covered by EDC	0.205-0.305	0.205-0.230	0.218	0.192	0.187	0.185	0.182
Covered by IPP	0.600-0.925	0.250-0.275	0.200	0.197	0.192	0.190	0.187
Subsidy rates							
Poor households in rural areas below 10 kWh per month	0.000	0.000	0.120	0.119	0.116	0.114	0.113
Poor households in Phnom Penh below 50 kWh per month	0.000	0.153	0.153	0.153	0.153	0.153	0.153
Poor pumping in agriculture sector from 21:00 to 7:00	0.000	0.000	0.120	0.119	0.116	0.114	0.113

Source: CBR[4]

power plants, tariffs are expected to decline in the future (Table 1). However, with the on-going national power grid upgrade works, the tariffs will also have to compensate the related costs. Besides the regular rates, the Government also provides tariff reductions and subsidies (Table 2).[10]

TABLE 2

Dry season tariffs in Cambodia 2014

Project name	Rate (US$ per kWh)
Phnom Penh (households)	0.18
Phnom Penh (businesses)	0.19
Grid-connected towns and urban areas	0.25-0.40
Rural areas (mostly diesel generators)	0.50-1.00
Battery (car batteries) charging stations (using diesel and found in 35% of rural villages)	4.00

Source: CBR[4]

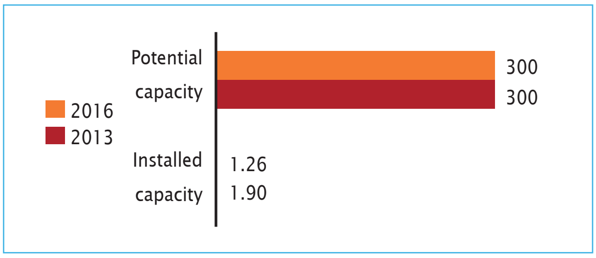
Small hydropower sector overview and potential

Plants with installed capacity of up to 10 MW are defined as small. Current installed capacity is approximately 1.26 MW with an additional estimated potential of approximately 300 MW indicating that just 2 per cent of the country's small hydropower (SHP) potential has been developed.[10] In comparison to data from the *World Small Hydropower Development Report* (*WSHPDR*) 2013, the potential has remained the same while the installed capacity has decreased marginally (Figure 6). This is due to a more accurate assessment of the country's current installed capacity.[6]

Available data and information on SHP is limited in Cambodia. Installed capacity as of 2015 consists of three projects constructed under grant aid from the Government of Japan and managed and operated by EDC (Table 3). 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.

FIGURE 6

Small hydropower capacities 2013-2016 in Cambodia (MW)



Sources: EDC,[10] *WSHPDR 2013*[6]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

TABLE 3

Operational SHP plants in Cambodia

Project name	Capacity (MW)	Location
O'chum 1	1.000	Ratanakiry
O' Mleng	0.130	Mondulkiry
O' Romis	0.130	Mondulkiry
Total	**1.260**	

Source: MME[9]

There are an additional nine projects at an advanced study stage with a combined installed capacity estimated at 20 MW (Table 4). A further 39 sites with a potential of 30 MW have also been identified and are in the reconnaissance stage (Table 5).

Cambodia has a total hydropower potential of approximately 10,000 MW with seven hydropower plants of 1,326 MW that are either operational or expected to be completed by 2017. Thus only a fraction of the 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 4

Small hydropower sites in Cambodia at advanced study stage

Project Name	Capacity (MW)	Location
Prek Por	4.80	Mondulkiry
Stung Kep	4.10	Kep City
O' Phlai	3.40	Mondulkiry
O' Sla Up Stream	1.90	Koh Kong
Stung Siem Reap 3	1.70	Siem Reap
O' Turou Trao	1.12	Kampot
O' Katieng	1.00	Ratanakiry
Stung Chikreng	0.80	Siem Reap
Prek Teuk Chhu	0.76	Kampot
Total	**19.58**	

Source: MME [9]

Renewable energy policy

According to the Power Development Plan, renewable energy is expected to account for more than half of the total energy production by 2020. In general, 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, the REF aims to promote and encourage private sector participation in providing sustainable rural electrification services such as the exploitation and economic application of technically and commercially well proven new and renewable energy technologies.[7]

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. In addition to the electrification rate targets outlined above, the REMP aims at 15 per cent of rural electricity supply from solar and SHP by the end of 2015.

By 2013, import taxes on solar PV components and biomass and solar water heating components were substantially reduced from 30 per cent to 7 per cent

TABLE 5

Potential SHP sites in Cambodia at reconnaissance stage

Project name	Capacity (MW)	Location
O Sla Downstream	4.483	Koh Kong
Phnom Batau Downstream	4.197	Koh Kong
Stung Sva Slab	3.804	Kampong Speu
Phnom Tunsang Upstream	3.143	Koh Kong
Phnom Tunsang Downstream	3.002	Koh Kong
Phoum Kulen	1.561	Siem Reap
Tum Nup Garaing	1.500	Siem Reap
Stung Prey Klong	0.886	Pursat
Preak Antap	0.844	Kampong Cham
Stung Boribour	0.813	Kampong Chhang
Prek Toeuk Chhu	0.762	Kampot
Upper Stung SiemReap	0.656	Siem Reap
Preak Thum	0.506	Siem Reap
Stung Bannak	0.403	Kampong Chhang
Stung Moung 1	0.400	Battambang
Stung Moung 2	0.400	Battambang
O Sam Kaong	0.334	Siem Reap
Pteak Kaoh Touch	0.317	Kampot
Kball Chay	0.312	Sihanoukville
Stung Tras	0.243	Kampot, Kampong Speu
Stung Kraing Ponley	0.221	Kampong Chhang
Prek Dak Seur	0.201	Mondulkiry
O Sam Raong	0.149	Siem Reap
Chruroh Rokar	0.119	Kampot, Takeo
Snam Prampir	0.101	Kampot
Stung Pursat 1	0.100	Pursat
Stung Prey Klong	0.100	Pursat
Tomnup Kuon Sat	0.100	Kampot
O Kachagn	0.082	Ratanakiry
Stung Touch	0.079	Siem Reap
Bay Srok	0.078	Ratanakiry
O Chum 3	0.074	Ratanakiry
O Yong Ngol	0.068	Mondulkiry
Busra	0.054	Mondulkiry
O Pramoie	0.036	Pursat
Takeo Waterfall	0.030	Takeo
Ochhleung	0.030	Takeo
Phoum Kbal Spean	0.018	Siem Reap
Ta Ang	0.010	Ratanakiry
Total	**30.22**	

Source: MME[9]

and from 15 per cent to 0 per cent, 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 PV installation is also stimulated by the two programmes implemented by the REF and the MME, which are the Solar Home Systems (SHS) Programme and the Power to the Poor (P2P) Programme funded by the World Bank and AFD, respectively.

In 2012, the Government issued another Royal Decree to integrate the REF with EDC. Part of this integration requires that EDC, through REF, facilitates rural access to electricity under the Solar Home System programme.[8] In 2013, the REF also received US$4 million from EDC for its rural electrification programme contributing to the Solar Home Systems Programme, Power to the Poor Programme and a programme aimed at improving existing and developing new electricity infrastructure in rural areas.

Barriers to small hydropower development

To attract more investors and reduce risk in SHP investments there is a need to refine investment cost, collect hydrological data, and mitigate social and environmental impacts to make projects more technically and the 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, which are summarized below:

- High project costs. SHP is usually located in remote areas with limited access and far away from load centres, which implies additional investment in infrastructure.
- Lack of policy and legal framework. The policy and legal framework need to be created, e.g. concessionary duties and taxes concerning imports of SHP equipment.
- Access to financing for SHP investment. 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 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 more detailed financial analysis for investment purposes.
- Institutional capacity for planning, implementation and operation. There is a great lack of technical knowledge and operational skills. 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, NGOs, private investors and financial institutions) is another difficulty in the absence of a comprehensive policy on SHP development.

3.4.2 Indonesia

Gonzalo Marzal Lopez, International Center on Small Hydro Power (ICSHP)

Key facts

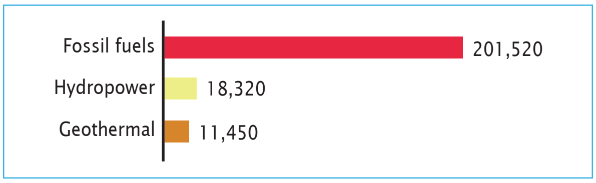
Population	254,454,778[1]
Area	1,992,750 km^2
Climate	Indonesia has a tropical climate, with high humidity and high temperatures. There are two seasons: a rainy season from November to March and a hot, drier season from April to October. Temperatures in the capital, Jakarta, generally range from 21°C to 33°C with humidity between 60 and 80 per cent.[2]
Topography	Indonesia is made up of more than 17,000 islands, about 6,000 of which are inhabited. The total land area is about 1.9 million km^2, making it the largest archipelago in the world. Five major islands make up 90 per cent of the total land area. These are Sumatra, Java, Sulawesi, Kalimantan and New Guinea. Indonesia also contains about two smaller archipelagos, the largest of which are Nusa Tenggara and the Maluku Islands, and sixty smaller archipelagos. Most of the larger islands have volcanic mountains. Puncak Jaya (4,884 metres) on New Guinea and Mount Rinjani (3,726 metres) on Lombok are the highest peaks in the country.[2]
Rain pattern	Average yearly rainfall in Indonesia is approximately 2,700 mm. In lowland areas it ranges from 1,300 to 3,200 mm, while in the mountains it can reach as much as 6,100 mm.[2]
General dissipation of rivers and other water sources	Rivers are found in every part of the islands and play an important role in irrigation and transportation. Major rivers can be found on Kalimantan, Java, Papua, and Sumatra. The country's longest river, the Kapuas (1,143 kilometres), is on Kalimantan, flowing from the north-central mountains to the South China Sea. Other major rivers on Kalimantan are the Barito, Mahakham, and Rajang. Southern Kalimantan is crisscrossed with a network of hundreds of smaller rivers.[2]

Electricity sector overview

In 2014, installed capacity in Indonesia was approximately 51,620 MW.[12] The total generation of electricity in 2014 was approximately 230,000 GWh.[18] Eighy-seven per cent of total generation came from fossil fuel sources, 8 per cent from hydropower and 5 per cent from geothermal. Coal accounted for slightly more than half of the power generated from fossil fuels.[19] Oil-fired generation has declined along with oil production.

FIGURE 1

Electricity generation by source in Indonesia (GWh)



Source: EIA[19]

The state-owned company Perusahaan Listrik Negara (PLN) is the major provider of electricity and electricity infrastructure in Indonesia. As of 2014, it operated about 70 per cent of the country's generating capacity through its subsidiaries and maintained an effective monopoly over distribution activities.[4] The power sector is regulated by the Ministry of Energy and Mineral Resources and its sub-agencies. These include the Directorate General of New and Renewable Energy and Energy Conservation. The current regulatory framework is provided by Electricity Law N°. 30/2009 and its implementing regulations.

In 2010 the rural electrification rate was 68 per cent.[6] It increased to 81 per cent in 2013, 84 per cent in 2014 and 87 per cent in 2015.[5,12,19] The eastern part of the country has a lower electrification rate compared with the western part with some provinces such as Papua having an electrification rate of 43 per cent.[7] Because capacity growth has not kept pace with electricity demand growth, grid-connected areas have also suffered from power shortages. The Government plans to develop an additional 57 GW of generating capacity to reach its target of 92 per cent electrification by 2021.[8]

The electricity tariffs paid by end-users are regulated by the Government of Indonesia. The 37 tariff classes are organized into six groups: social, household, business, industry, Government and special services. The average selling price in 2012 was approximately US$0.71/kWh while the cost of generation was US$10.5/kWh. The difference is funded through a government subsidy running at US$9.5 billion per annum.[8]

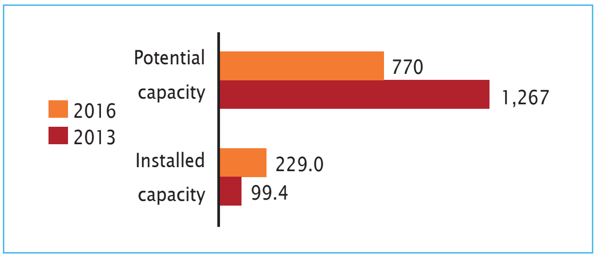
Small hydropower overview and potential

Indonesia classifies hydropower up to 1 MW as micro and from 1 MW to 10 MW as mini. For the purpose of this report, the definition of small hydropower (SHP) up to 10 MW will be used. SHP installed capacity is 229 MW.[8] The total SHP potential is estimated at 770 MW.[8,9]

The Government is prioritizing SHP development in order to increase rural electrification. It is expected that there will be strong growth as a result of a recently revised feed-in tariff (FIT) system and the country's desire to develop its renewable energy sector.

FIGURE 2

Small hydropower capacities 2013-2016 in Indonesia (MW)



Sources: *WSHPDR 2013*,[3] PWC,[8] GIZ[9]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Much of the SHP development is undertaken by independent power producers with most of the potential concentrated in Papua and Sumatra. PT Medco Power Indonesia, PT Sumberdaya Sewatama and others are preparing multiple sites in West Java and South Sulawesi.[8] In 2013 and 2014, Indonesia Hydro Consult carried out over 30 feasibility studies, the majority of which were small hydro scale projects.[15]

PT Inti Duta Energy is expected to develop 50 MW of mini hydropower plants located in Java and Sumatra.[13] Meanwhile, PT Bhakti Putra Bangsa (TIRASA) and the Dutch company Royal Haskoning DHV are building four SHP plants in Java with a combined capacity of 15.6 MW, which represent the first stage of a SHP development project of 100 MW.[16]

The ASEAN Hydropower Competence Centre (HYCOM) in Bandung facilitates ASEAN-wide knowledge exchanges on hydropower of 1 kW to 1 MW. The objective of HYCOM is to provide an ASEAN-wide competence centre, offering training as well as facilitating research and development to the SHP sector. It has implementing partners such as PT Entec Indonesia and Technical Education Development Centre of Bandung as well as supporting partners such as the REPIC platform (Renewable Energy and Energy Efficiency Promotion in International Cooperation), the Renewable Energy Support Program for ASEAN, the ASEAN Centre for Energy and Deutsche Gesellschaft fuer Internationale Zusammenarbeit (GIZ). Its activities include:

- Training programmes;
- Research and development;
- Laboratory testing of electromechanical equipment with regard to reliability, safety and efficiency;
- Support for the development of mini hydropower sites;
- Networking and exchange of SHP related information.[10]

Renewable energy policy

The Government has demonstrated its interest in further development of the renewable energy sector. However, Indonesia is still one of Asia's largest emitters of greenhouse gases due to intensive urban and industrial development and deforestation. Indonesia has applied incentives such as tax reductions and FIT that could help boost the underachieving sector. Currently, renewable energy sources account for 5-6 per cent of the country's energy consumption.[11] The Government is working on mitigating climate change and has announced that the country will reduce its greenhouse gas emissions by 26 per cent by 2020.

Currently, fossils fuels dominate the country's energy supply. The Climate Investment Fund plan for Indonesia proposed co-financing of US$400 million to support the goals of reaching 17 per cent of energy generation from renewable energy sources and improving energy efficiency by 30 per cent by 2025. Furthermore, PLN proposed that by 2024 the share of renewable energy will reach 16 per cent, and oil consumption will decrease from 11 per cent (in 2014) to 1.5 per cent.[12] Indonesia will accelerate the use of renewable energy by establishing its first geothermal exploration risk reduction fund and developing technical capacity through exchange with other geothermal power producing countries.[12]

Regarding the legal framework, several laws have been promulgated in order to promote the use of renewable energies in the country. For instance, Law N°.30/2007 stated that the national and local authorities should promote renewable energy and allows them to provide incentives for certain periods until reaching financial development stage.

Ministerial Regulation N°.31/2009 on Small and Medium Scale Power Generation using Renewable energy stated that the state-owned company PLN is obliged to purchase electricity from small and medium-scale (up to 10 MW) renewable energy power plants developed by cooperatives, community or business entities. The Regulations of the Minister of Finance N°. 21/PMK.011/2010 and 24/PMK.011/2010 on Renewable Energy Incentives set tax incentives for renewable energy developers, including import tax and import duty reductions, tax holiday and tax exemptions.

Legislation on small hydropower

Indonesia has set up FITs for hydropower projects with installed capacity of below 10 MW. According to the Regulation of the Ministry of Energy and Mineral Resources N°. 19/2015, FITs vary from US$0.068 per kWh for plants connected to a medium voltage grid to US$0.144 per kWh for plants connected to a low voltage grid. In addition, there are multiplying factors (F) depending on the installation region and ranging from 1 for Java, Bali and Madura to 1.6 for Papua and West Papua.[20]

Barriers to small hydropower development

The country has to cope with significant barriers to the development of SHP even though the Government has created legislation and is promoting SHP and other renewable energies.

Structural and policy-related barriers:

(a) Lack of standardization of procedures and technical codes;
(b) Non-standardized procedures for power purchase agreements;
(c) Lack of technical support for connecting SHP plants to the grid.
(d) Barriers related to technical and institutional capacities:
(e) Lack or poor quality of preliminary financial feasibility analysis.
(f) Technical problems resulting from low design standard and construction quality impacting on civil and electromechanical aspects of a project.
(g) Local equipment design and manufacturing capability is limited and is mostly concentrated on Java with rated turbine capacity available being below 1MW. Even with tax exemptions, imported equipment can be expensive and spare parts can be difficult to source and obtain.
(h) There are no mechanisms in place, such as product liability, quality assurance and technical control institution that would warrant the quality of SHP equipment imported or manufactured locally.
  (i) Plant operation and maintenance procedures are not always properly set up.
  (ii) Limited access to financing mechanisms.

Barriers related to awareness and dissemination of information:

- Many institutions and decision makers are not aware of the possibilities for SHP development. As a result, conventional energy options are preferred.
- Basic data (hydro-meteorological, geological and topographical) required for project assessment are often missing or difficult to obtain, especially for remote regions.

3.4.3 Lao People's Democratic Republic

Akhomdeth Vongsay, Ministry of Energy and Mines; Manish Shrestha, Asian Institute of Technology

Key facts

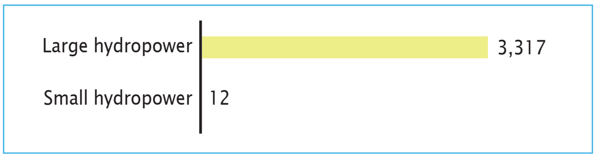
Population	6,803,699[1]
Area	236,800 km[2]
Climate	Mainly tropical, with a seasonal monsoon with warm, humid weather and heavy rainfall during the wet season. The average yearly temperature is around 29°C. The warmest temperature can reach 40°C. During cooler months the temperature often drops to 15-20°C at night in lower land, for example, in the capital city Vientiane, and can also drop below the freezing point in the mountainous areas.[2]
Topography	Laos is largely mountainous. Elevations are typically above 500 metres above sea level with narrow river valleys and low agricultural potential. This mountainous landscape extends across most of the north of the country, except for the plain of Vientiane and the Plain of Jars in the Xiangkhoang Plateau. The lowest point is on the Mekong River (70 metres) while the highest point is Phou Bia (2,817 metres).[3]
Rain pattern	Rainfall varies regionally, with the highest records on the Bolovens Plateau in Champasak Province averaging 3,700 mm per year. Rainfall stations located in the main cities recorded mean yearly rainfall of 1,440 mm in Savannakhét, 1,700 mm in Vientiane and about 1,360 mm in Louang Phrabang.[3]
General dissipation of rivers and other water sources	The Mekong River is the largest in the country, comprising some 90 per cent of the territory within its basin. There are 39 main tributaries in the Mekong River basin: Ou, Suang and Khan are in the northern region, Ngum and Nhiep in the northern-central region, San, Theun-Kading and Bangfay in the central region, Banghiang in the Savannakhet plain in the central-southern region, Done in the southern region and Kong in the south-eastern region.[2]

Electricity sector overview

The electricity sector in Laos has developed rapidly over the past decade; in 2008, installed capacity was below 700 MW, by 2010 it had increased to more than 2,500 MW.[13] The total installed capacity in 2015 of Laos was approximately 3,329 MW with 100 per cent of installed capacity from hydropower (Figure 1). With 29 power plants in operation, electricity generation was approximately 16,000 GWh. In addition, there are 45 projects comprising a total of 6,185 MW under construction.[4]

FIGURE 1

Installed electricity capacity in Laos (MW)



Source: Department of Energy Policy and Planning, Ministry of Energy and Mines[4]

Electricity generation is predicted to increase by 11 per cent per year between 2005 and 2025. Only 10 per cent of the produced electricity is used domestically, whereas 90 per cent is exported to neighbouring countries. Thailand is currently the largest buyer of electricity from Laos. Part of the electricity Thailand purchases is exported to Viet Nam and Cambodia and some cooperation with China might be developed in the near future.[6] At the same time, Laos has to import electricity from Thailand, China and Viet Nam for remote northern areas of the country that are not connected to the national grid.[16]

Domestic electricity demand is estimated to increase to 2,863 MW in 2025 compared with 425 MW in 2006. This increase will be covered mainly by hydropower and coal.[8] Electrification is one of the major objectives of the Government of Laos. The electrification rate has increased quickly in Laos: from 15 per cent in 1995, to 70 per cent in 2010 and 82 per cent in 2013.[13,14] The target is to provide access to electricity to 90 per cent of the population by 2020.[5]

The main regulator of the electricity market of Laos is the state-owned company Electricité du Laos (EDL). Electricity tariffs in Laos used to be subsidized by the Government and did not compensate for the real cost of electricity generation and distribution. That is why the Government undertook a reform of electricity tariffs aimed at ensuring financial sustainability of the sector. A gradual increase of electricity tariffs was scheduled for the period 2006-2017 with, for example, residential low-consumption (up to 25 kWh) tariffs to be increased almost threefold by 2017.[17]

In Laos, tariffs are based on monthly consumption. As of 2015, residential tariffs were US$0.042/kWh for consumption up to 25 kWh/month, US$0.05/kWh for 26-150 kWh/month and US$0.12/kWh for more than 150 kWh/month.[7]

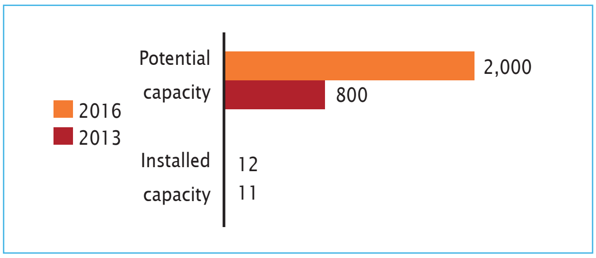
Hydropower is the most important energy resource in the Laos with the technical potential estimated at around 26,000 MW, excluding small-scale hydropower sites (below 15 MW), which represent a potential of 2,000 MW.[7]

Small hydropower sector overview and potential

In Laos, hydropower projects with capacity below 15 MW are classified as small hydropower (SHP).[7] Total installed capacity of SHP is 12 MW while the potential is estimated to be 2,000 MW indicating that less than 1 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016* installed capacity has increased by approximately 14 per cent, while estimated potential has increased by 150 per cent.

FIGURE 2

SHP capacities 2013-2016 in Laos (MW)



Sources: *WSHPDR 2013*,[11] Department of Energy Policy and Planning, Ministry of Energy and Mines[12]
Note: The comparison is between data *WSHPDR 2013* and *WSHPDR 2016*.

The development of SHP could play an important role in meeting the country's objectives of increasing rural electrification from the current level of 82 per cent to 90 per cent by 2020.[13] SHP could provide a solution with minimum production cost to remote areas, which currently rely on imported electricity.[8]

In the past, SHP development was not sustainable due to recurrent natural disasters, lack of management and budget control for maintenance. To promote the development of SHP resources, the Government will implement measures to address and mitigate the existing technical, financial, procedural and institutional barriers that SHP developers have to cope with. Currently, hydropower technologies are relatively popular in remote villages as a primary source of electricity.[9]

Pico hydropower plants have played an important role in rural electrification where grid connection has not be established. As per Lao Institute for Renewable Energy estimates, approximately 60,000 units of pico hydropower equipment have been installed in the country until 2008 providing electricity supply to about 90,000 households. Those were sourced from China and Viet Nam and had capacity of 300-1,000 W.[9] Spare parts for pico units are sold in small shops in remote areas. Units range in price from US$35 to US$200 and may last up to five years if properly serviced. Even though no installation, operation and maintenance manuals are available, users learn how to install the units from the experiences of others.[9]

Renewable energy policy

The Government of Laos is currently drafting a strategy policy for renewable energy. Policies on the promotion and development of renewable energy have emphasized the role of hydropower and are starting to focus on producing feedstock for biofuel, which also has potential in the country. The 2025 goal stated that electricity from renewable energy sources should reach a 30 per cent share of total energy consumption in the country, including the spheres of production, agriculture, forestry, processing and industry.[10]

The Government defines priorities for development as follows:

- Promote sustainable renewable energy development to ensure the supply of energy for social and economic development.
- Facilitate financial aspects such as tax exemptions and incentives for investors.
- Prepare and improve laws and regulations related to the facilitation of renewable energy development.[10]

The Government of Laos aims to develop such renewable energy resources as biofuels, small-scale power plants, solar, biomass, biogas, wind and other alternative fuels for transportation. The objectives of the Government include:

- To reduce fossil fuel import;
- To reach a 10 per cent share of biofuels in total transport energy consumption;
- To promote public, private, local and foreign investment in the energy sector;
- To develop 50 MW of wind power;
- To increase residential use of solar energy in 331 villages within 11 provinces between 2010 and 2020.[8]

Legislation on small hydropower

The 1996 Water and Water Resource Law (Law No. 106) governs the management, exploitation, development and use of water and water resources, of which ownership is vested in the people of Laos as a whole. As per Article 8, the Ministry of Agriculture and Forestry is responsible for the survey of water resources and river basins. The right to utilize water resources is determined by classification, and as per Article 16, hydropower generation is considered medium-scale or large-scale use. Medium and large scale use must obtain permits, conduct feasibility studies including environmental impact assessments (EIAs), conduct sociological studies and an overall plan before the Right to Use water resources is granted (Article 19).[15]

The Water and Water Resource Law also has special provisions for hydropower, included in Article 25, titled Promotion of Watershed and Water Resource Protection for Hydropower Development, which states that the Government will encourage the development of hydropower projects in line with existing legislation to properly and fully utilize the natural resource.[15]

Barriers to small hydropower development

In recognition of the difficulties experienced in setting up SHP projects in Laos, the Asian Development Bank (ADB) has provided assistance to SHP projects, including support with the preparation of feasibility studies and identification of barriers that need to be addressed to encourage investment in SHP projects. The analysis of barriers is expected to contribute towards increasing investment in SHP projects and meeting the targets for rural electrification. Issues related to streamlining procedures and providing incentives to private developers are being addressed by the Government.[9]

The most important barriers to the development of small and mini hydropower development are:

- Complex regulations requiring case-by-case negotiation for power purchase agreement;
- Limited clarity on power purchase agreement off-take tariffs, taxes, royalties, and duties;
- Inadequate institutional capacity at the level of provincial authorities, which are empowered to approve only up to 5 MW of small and mini hydropower capacity, whereas projects from 5 MW to 50 MW have to be approved by the national government;
- The need for developers to apply for longer-term loans than commercial banks normally offer.[9]

3.4.4 Malaysia

Engku Ahmad Azrulhisham, Universiti Kuala Lumpur

Key facts

Population	31,049,995[1]
Area	329,847 km[2]
Climate	Characteristic uniform temperature, high humidity and high rainfall. Daytime temperatures can rise above 30°C year-round and night time temperatures rarely drop below 20°C.[3] Winds are generally light. Days without sunshine are rare, except during the north-east monsoon season, which usually commences early November and ends in March.[4]
Topography	The topography of Peninsular Malaysia, Sabah and Sarawak is generally composed of coastal plains with hills and mountains in located in the interior part of the country. The lowest elevation is at the coasts, whereas the highest point Gunung Kinabalu (4,100 metres) is in northern Sabah.[5]
Rain pattern	The seasonal wind flow patterns coupled with the local topographic features define the rainfall distribution patterns over the country. During the north-east monsoon season the exposed areas, such as the east coast of Peninsular Malaysia, Western Sarawak and the northeast coast of Sabah, experience heavy rains. Inland areas or areas that are sheltered by mountain ranges are relatively free from its influence.[4] The yearly mean rainfall in 2014 was 2,875 mm.[6]
General dissipation of rivers and other water sources	The longest rivers in Peninsular Malaysia are the Pahang, the Kelantan and the Perak. In the eastern part of Malaysia, the longest rivers are the Rajang and the Kinabatangan. Most rivers of the country have steep slopes especially those in Sarawak. The country's largest lake, Kenyir, was created by a dam project and is located in the north-eastern region of Peninsular Malaysia. Bera is the largest natural lake located in the south-west of Pahang state.[4]

Electricity sector overview

The total installed capacity of Malaysia in 2013 was 29,748 MW with 24,105 MW in Peninsular Malaysia, 2,196 MW on Sabah and 3,446 MW on Sarawak.[27] In terms of the electricity demand growth, the grid system's maximum demand of 16,562 MW was recorded on 13 May 2013, surpassing the initial target of 16,324 MW by 1.5 per cent and the 2012 record of 15,826 MW by 4.7 per cent.[7] The growth was by no means a blip as the system also registered maximum daily consumption of 344.42 GWh against 328.72 GWh recorded in 2012. The 2012 daily energy record was surpassed 54 times in 2013 indicating a sustained, high system demand profile.[7]

The national transmission grid consists of three parts, which are operated by different companies: Tenaga Nasional Berhad (TNB) in Peninsular Malaysia, Sabah Electricity Sendrian Berhad (SESB) in Sabah and Sarawak Energy Berhad (SEB) in Sarawak.[28]

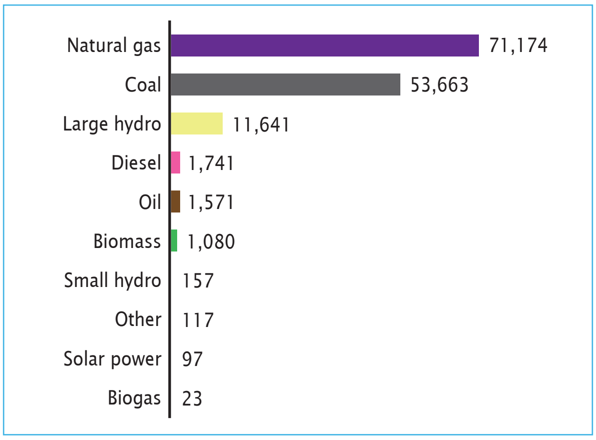
In terms of System Average Interruption Duration Index (SAIDI), performance recorded by the national utility company Tenaga Nasional Berhad (TNB) in Peninsular Malaysia was good in 2013 and showed a downward trend compared to SAIDI of 2012. The overall SAIDI was at 60.35 minutes per customer per year and still below the 2013 target which is 65 minutes per customer per year.[7] Sarawak's SAIDI was slightly increased from 132 minutes per customer per year in 2012 to 168 minutes per customer per year in 2013.[7] However, Sabah still faces a shortage of generating capacity and low level of reliability. Ability of existing stations to system demand is still low if unanticipated shutdowns at major power stations occur. Overall SAIDI in Sabah for 2013 was 423.99 minutes per customer per year, that was a decrease of 23.9 per cent from 557 minutes per customer per year in 2012.[7]

Sales of electricity rose from 97,243 GWh in 2012 to 100,560 GWh in 2013. The cumulative growth of 3.42 per cent was mainly driven by commercial and residential sectors that recorded annual growth rates of 4.42 per cent and 6.02 per cent, respectively. While the growth in industrial consumption was slower with 1.2 per cent, the industrial sector remains the largest consumer with a market share of sales at 43 per cent followed by commercial consumption at 35 per cent and residential consumption at 2 per cent.[7] Gas and coal remained the most used fuels for power generation at 47.99 per cent and 25.73 per cent respectively, followed by hydroelectric power plants at 14.73 per cent and biomass at 2.97 per cent (Figure 1).[7]

With an estimated annual consumption of 21 million tonnes in 2013, coal is the main fuel for power generation and additional 5,000 MW of coal-fired capacity is planned

FIGURE 1

Electricity generation in Malaysia (GWh)



Source: Energy Commission Malaysia (December 2013) [7]

to be commissioned between 2015 and 2019. Coal-fired generation represents about one-third of the installed power generation capacity and accounted for nearly 43 per cent of the electricity produced in 2013. Hence the performance and reliability of the coal-fired power plants have a significant and direct impact on the electricity supply situation in Malaysia. Meanwhile, in Peninsular Malaysia new large-scale hydroelectric facilities with estimated capacity of 1,237 MW will be developed and commissioned in stages from 2015 to 2024, adding to the 1,899 MW already in operation. The total large-scale hydroelectric plant capacity of 3,136 MW should be able to serve system peaking requirement for years to come.[8]

For Renewable Energy (RE) projects, the Sustainable Energy Development Authority of Malaysia (SEDA) has targeted capacity of more than 800 MW from the feed-in tariff (FIT) scheme with the bulk of the capacity coming from small hydroelectric, biomass and solar PV. With surcharges on electricity bills for the contribution to the Renewable Energy Fund revised from 1 per cent to 1.6 per cent effective since 1 January 2014, the targeted capacity for RE will be revised accordingly to reflect increase in surcharge quantum.[8] The long term capacity plan has already incorporated RE capacity as part of overall supply system with estimated contribution of more than 2.5 per cent of the energy from RE power plants under the FIT mechanism.[8] However, large scale RE capacity including solar PV does not fall under this FIT scheme, and will be considered on its merit as replacement of conventional power plants.

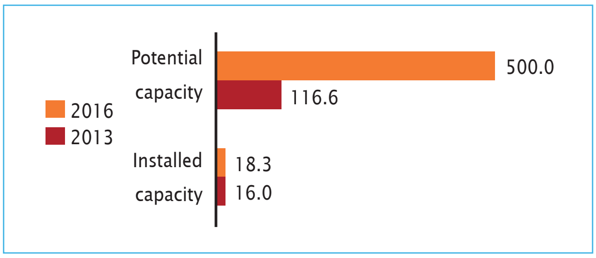
In terms of ensuring universal access to modern energy services, by 2013 the electrification programme in Malaysia has successfully penetrated 96.86 per cent of the country. The electricity access rate is 99.72 per cent in Peninsular Malaysia, 92.94 per cent in Sabah and 88.01 per cent in Sarawak.[9] In terms of rural electrification, in 2012 99.8 per cent of rural households in Peninsular Malaysia had access to 24-hours electricity, while 88.7 per cent and 82.7 per cent had access in Sabah and Sarawak, respectively.[10] The increasing cost of rural electrification projects is due to scattered and remote locations of the population. Rural electrification is mainly grid-based and for areas that are too far from the grid, stand-alone alternative systems such as solar hybrid and mini hydro are available.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Malaysia is up to 10 MW. Installed capacity of SHP is 18.3 MW while the potential is estimated to be 500 MW.[14,15] Figure 2 below shows comparison of SHP potential and installed capacity with the *World Small Hydropower Development Report* (*WSHPDR*) *2013*.

FIGURE 2

SHP capacities 2013-2016 in Malaysia (MW)



Sources: Sustainable Energy Development Authority of Malaysia (2015),[14] Nor Afifah Basri,[15] *WSHPDR 2013*[26]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

In Malaysia, SHP refers to hydropower application based on run-of-river schemes of sizes of up to 10 MW.[11] Hydropower accounts for 13 per cent of total installed capacity in Malaysia, of which 0.5 per cent is contributed by SHP.

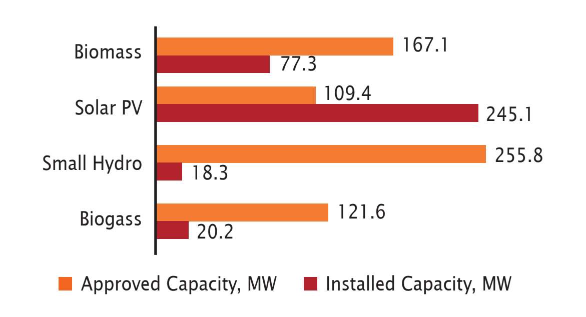
With the hilly topography running almost the entire length and width of the country and an abundant number of streams, Malaysia has a lot of SHP potential. Potential hydropower sites are mainly located on tributaries flowing from the principal rivers of Kinabatangan (564 kilometres in length), Rajang (560 kilometres), Pahang (434 kilometres), Baram (400 kilometres), Lupar (230 kilometres), and Limbang (196 kilometres).[12]

The adoption of SHP has been making progress in Malaysia, which has been spurred on by the Renewable Energy Act 2011 that was approved by the Parliament in April 2011. As a result of this law, an FIT scheme was adopted in December 2011. Under the FIT scheme, small power generation plants that utilize RE can apply to sell electricity to the utility through the distribution grid system owned by the national utility company Tenaga Nasional Berhad (TNB) through the RE Power Purchase Agreement (REPPA).[13]

In 2015 the installed capacity of SHP under the FIT programme reached 18.3 MW, contributing over 55 GWh of power generated.[14] As of May 2016, an additional 255.84 MW of SHP was approved by the Sustainable Energy Development Authority of Malaysia (SEDA) (Figure 3).[14]

FIGURE 3

FIT statistics of Malaysia (MW)



Source: SEDA (2016)[14]

Small-scale hydropower has become a popular alternative to large-scale hydropower projects because of their lower investment cost, higher reliability and limited environmental impact. According to a study by the Malaysia Energy Centre, the estimated long-term potential of SHP plants up to 10 MW is 500 MW.[15] The targeted installed capacity for SHP in this range is 490 MW by 2020 under the Malaysia renewable energy development plan.[15]

There are three general sources of capital available for SHP projects in Malaysia: equity, debt, and grant financing.[13] Equity investment presupposes purchasing ownership in a project. Debt investment is a loan to a project. In addition, since most SHP projects cannot compete with conventional fossil fuel-based technologies, the Government offers some fiscal incentives and grants financing to increase the margin of profitability of the projects outlined as follows (two options):

- Pioneer Status with 25 per cent income tax exemption on 100 per cent of statutory income for 10 years
- Investment Tax Allowance (ITA) of 100 per cent on qualifying capital expenditure incurred within a period of 5 years. This allowance can be set-off against 100 per cent of statutory income for each year of assessment [16]

Companies can also apply for import duty and sales tax exemption on equipment used to generate energy from renewable energy sources not produced locally and full sales tax exemption on equipment purchased from local manufacturers.

Moreover, a SHP project may benefit from the Green Technology Financing Scheme, another fiscal incentive promoted by the Government. Under this scheme, projects developed by legally registered Malaysian owned companies (at least 51 per cent) and utilizing Green Technology Financing Scheme could benefit from an up to MYR 50 million (approximately US$12 million) loan with 15 years tenure provided by participating local financial institutions.[15] In addition, the Green Technology developers can benefit from interest subsidies of 2 per cent from the total interest rate charged as well as a government guarantee of 60 per cent from the total approved loan.[17]

Renewable energy policy

Sustainable energy supply is essential for actualizing the Malaysian vision to become a high income country. The current power production and demand trends show that Malaysia has a reserve margin that will only last for the next few years. This calls for further investment, research and development in the country's power sector in order to meet the ever-increasing energy demand.

In 1981, the Government of Malaysia designed the Four-fuel Diversification Strategy to reduce over-dependence on oil and ensure energy reliability and security. The strategy aims for a balanced energy supply mix of oil, gas, hydropower and coal, as well as utilizing local resources to enhance security of supply. This policy has led to a significant shift from oil to natural gas, as it is seen as appropriate to compliment supply and environmental objectives as spelled out in the National Energy Policy.[18] The Four-fuel Diversification Strategy was further developed into Five-fuel Diversification Strategy. Under the current strategy, renewable energy resources were considered as the fifth fuel for the energy. Modalities on utilization of REs were presented in the National Renewable Energy Policy and Action Plan in 2009.[19]

The latest energy policy was implemented in 2010 under the 10th Malaysia Plan, which describes the new energy policy as a further step to encapsulating all efforts aimed at ensuring economic efficiency, security of energy supply and meeting the social and environmental objectives established in the National Energy Policy of 1979.[20] The New Energy Policy 2010 identified five strategic pillars for providing the primary areas of focus to achieve the National Energy Policy objectives. The five strategic pillars are:

- Energy pricing should be gradually rationalized in order to match market price.
- Strategic energy supply is to be developed by diversifying energy resources, including renewable energy resources and nuclear energy.
- Energy efficiency should be increased in the industrial, residential and transport sectors.
- Energy governance and regulation should be improved, while mitigating the impact of reforms on the low-income group.
- Proper management of change and affordability.[21]

The new policy also emphasizes the National Green Energy Policy (NGEP), under which special consideration was granted to the RE development plan.[18] Short-term goals vested in NGEP are as follows:

- Increased public awareness and commitment for the adoption and application of renewable technologies through advocacy programmes;
- Widespread availability and recognition of renewable technologies through standards, rating and labelling programmes;

- Increased foreign and local direct investment in renewable technology manufacturing and services sector;
- Expansion of research, development and innovation activities in the field of renewable technologies.[22]

Barriers to small hydropower development

Despite the potential benefits of renewable energy development, particularly SHP, its full exploitation is constrained by certain factors. For example, some of the issues in the water sector include localized water shortages during dry seasons, pollution affecting more than half of the country's rivers, climate change as well as institutional and regulatory complexity and inconsistency.[11]

The common barrier in the development of SHP project is capital cost, which is relatively higher than for conventional power plants. Maximizing local content by utilizing locally manufactured components and designing correct components with appropriate operation strategies will alternatively reduce the project costs.[23] In addition, most SHP turbines require a static head of at least 10 metres. It is impossible to use conventional turbines in flat areas with little elevation.[24] Hydropower also requires expensive civil and hydro-mechanical works, piping and expensive control systems.

Other barriers include:

- Heavy rainfall causing flooding and overflow and thus reducing electricity generation;
- Inefficient filter design to filter out sand, debris and dirt;
- Poor design and construction quality control resulting in too short de-sander basins, too wide screens;
- Complicated regulatory requirements for land acquisition and environmental impact assessment;
- Risk of water pollution during construction works resulting from logging activities.[25]

In addition, the access to water and the use, control and diversion of water flows are regulated by federal and state laws. There are other regulations that apply to physical alteration of a stream channel or bank that may affect water quality or wildlife habitat.[11]

Although hydropower technologies are highly developed and sustained, further innovative research is still needed. Research on siltation such as how to solve high sedimentation problems of the river should be carried out.

3.4.5 Myanmar

Tim Myint, Suntac Technologies

Key facts

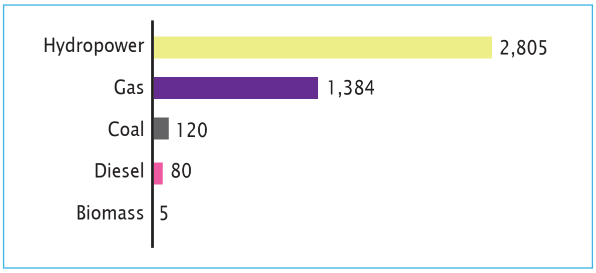
Population	53,437,159[1]
Area	676,577.2 km²
Climate	Tropical monsoon climate with three distinct seasons. During the wet season between May and October average temperatures are between 25°C and 30°C. During the cold and dry season from November to February, temperatures range between 20°C and 24°C. During the hot and dry season from March to April temperatures range between 30°C and 35°C.[2]
Topography	The topography is generally low in the coastal and deltaic regions but rises to about 6,000 metres in the north of the country. As mountain ranges generally run from north to south, the major river systems also flow from north to south. The highest mountain is Hkakabo Razi at 5,881 metres above sea level.[2]
Rain pattern	Average annual rainfall is 2,341 mm but varies by region. Annual rainfall in the coastal and deltaic region can reach up to 5,000 mm whereas it is only about 600 mm in the dry central part of the country.[2]
General dissipation of rivers and other water sources	The country has four major rivers: Ayeyawady 2,063 km long, Sittaung 310 km, Thanlwin 1,660 km and Chindwin 1,151 km. The Ayeyarwady-Chindwin River basin drains over half of the territory. The Sittaung River basin, which is entirely located in Myanmar to the east of the downstream part of the Ayeyarwady, drains 5.4 per cent of the territory. The Thanlwin River basin drains almost 20 per cent of the territory, mainly the Shan plateau in the east and forms the border with Thailand for about 110 km. The Mekong river basin in the far east forms the border with Laos.[12]

Electricity sector overview

In 2015, the total installed capacity in Myanmar was 4,394 MW, of which 2,805 MW was from hydropower (63.8 per cent), 1,384 MW from gas, 120 MW from coal, 80 MW from diesel and 5 MW from biomass.[3] The total electric generation in 2014 was 12,247 GWh.[18]

FIGURE 1

Installed electricity capacity in Myanmar (MW)



Source: Government of Myanmar [3]

Electricity consumption was only 165 kWh per capita in 2013. The country's electrification rate almost doubled from 16 per cent in 2006 to 31 per cent in 2013 with Yangon City achieving the highest electrification rate (78 per cent), followed by Nay Pyi Taw (65 per cent), Kayah (46 per cent) and Mandalay (40 per cent). Although access to electricity has increased in recent years, Myanmar still has one of the lowest electrification rates in the world of 33 per cent. The electrification rate is higher in major cities but large parts of rural Myanmar have limited to almost no electricity at all (roughly 7.2 million unconnected households).[6] The rural areas have electrification rates at about 21 per cent.[4]

According to the projection of the Ministry of National Economic Development, the country's GDP will grow at an annual average rate of 7.1 per cent from 2015 to 2030. Demand for electricity is expected to grow at 9.6 per cent, increasing from 10,112 GWh in 2013 to 49,924 GWh in 2030. To meet the rising demand for electricity against the backdrop of continuous strong economic growth, Myanmar will need to expand the power sector including development of new generation sources and the expansion of transmission and distribution networks. A reliable electricity supply is crucial for the Yangon region, which has been and will be consuming around 50 per cent of the country's electricity supply.[5]

The Ministry of Electric Power (MOEP) is the main body responsible for overseeing the electricity sector. It comprises seven agencies the Department of Hydropower Planning, the Department of Hydropower Implementation, Hydropower Generation Enterprises (responsible for power generation), the Department of Electric Power, Myanmar Electric Power Enterprise (responsible for transmission, generation and system operations), the Electricity Supply Enterprise and the Yangon City Electricity Supply Board (both responsible for distribution). Furthermore, in 2013, the Government formed the National Energy Management Committee (NEMC) and the Energy Development Committee (EDC) in order to better coordinate administrative processes among the various ministries and agencies. The NEMC is responsible for the formulation of energy policies and plans in coordination with energy-related ministries.[6]

The Government has a goal set for at least 90 per cent of connections to be grid-based, and has also been looking into off-grid renewable energy power through the development of mini-grid hydro plants and off-grid solar home solutions. Those are especially crucial in remote rural areas where building larger grids can be costly and time consuming.

According to the MOEP, Myanmar can expect to reach an electrification rate of 47 per cent by 2020, 76 per cent by 2025 and 100 per cent by 2030. Myanmar has also worked to improve its electrical infrastructure by building more transmission and distribution lines, sub-stations and dams to generate more power. Moreover, Myanmar Investment Commission has introduced tax benefits for foreign investors and the Government has also upgraded its laws to make them compatible with the National Electrification programmes.

The MOEP is also responsible for policy and oversight as well as for the regulation of the power sector. It is in charge of all planning, operating and management activities for the sector. In the absence of a distinct regulatory framework to support the functional unbundling that will take place soon, the MOEP will need clear directions on how this could be achieved through a revised electricity law. The MOEP has prepared a draft concept note on power sector policy that outlines a new reform strategy to rationalize power sector institutions and functions, gradually commercialize the institutions, develop a regulatory framework through an electricity law, gradually adopt cost-based tariffs, promote private sector participation, increase rural access to electricity, undertake demand-side management and update the law and regulations on health and safety and sector-related offences.[5]

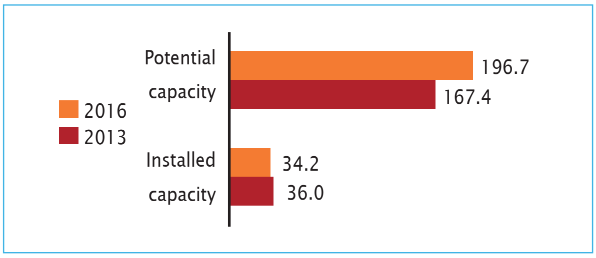
National grid electricity tariffs as of 1 November 2013, were US$0.03/kWh for household consumption up to 100 kWh and US$0.04/kWh for 101 kWh and above; US$0.08/kWh for industrial and commercial consumption up to 5,000 kWh and US$0.09/kWh for industrial and commercial consumption above 5,001 kWh, US$0.04/kWh for Government offices, and US$0.08/kWh for industrial use of Government departments. Off-grid consumer tariffs vary depending on the cost of generation by diesel or other means (e.g. solar or mini-hydropower) and range from about US$0.08 to US$0.3/kWh.[5]

Small hydropower sector overview and potential

There is no clear definition for small hydropower (SHP). However, it could be considered as up to 10 MW for SHP plants and 30 MW for mid-sized or medium hydropower plants according to the new Electricity Law (2014). This law allows regional governments to make agreements directly with the developer for up to 30 MW size plants (from any source of power) as long as they are not connected to the national grid. As of 2015, total installed capacity was 34.174 MW.[7] The total SHP potential was approximately 196.7 MW.[14]

FIGURE 2

SHP capacities 2013-2016 (MW)



Sources: Ministry of Electric Power,[3] *WSHPDR 2013*,[13] UNDP,[14] IRENA[16]
Note: The comparison is between data *WSHPDR 2013* and *WSHPDR 2016*.

With more than 300 identified SHP sites in Myanmar, the SHP potential is almost 200 MW (Table 1), which accounts for about 0.6 per cent of the country's total hydropower potential.[14]

TABLE 1

SHP potential in Myanmar

State and division	Mini/Micro hydro (1 kW-1 MW)		Small hydro (1-10 MW)	
	Sites	Capacity (MW)	Sites	Capacity (MW)
Kachin State	17	5.33	14	48.18
Chin State	11	3.48	2	2.80
Shan State	35	10.64	24	63.90
Sagaing State	5	0.81	3	13.30
Mandalay Division	3	0.65	2	6.25
Magway Division	1	0.10	2	11.00
Rahkine State	6	1.91	—	—
Kayah State	2	0.15	—	—
Bago Division	4	1.89	—	—
Kayin State	3	0.86	1	3.00
Mon State	5	1.24	—	—
Taninthayi Division	9	1.70	2	19.50
Total	**101**	**28.76**	**50**	**167.93**

Source: UNDP[14]

Current national electrification programmes include SHP plants as one of the candidates of renewable energy technologies (RET) for pre-electrification in such areas as Shan, Chin, Kayah and Chin States where SHP potential is relatively higher than in other regions and states.[8] In Shan State alone, there are several thousands of pico hydropower plants (< 5 kW), hundreds of micro hydropower plants (< 100 kW) and several mini hydropower plants (from 250 to 1,000 kW) installed by local private developers. They are rarely registered to any agencies or Government departments.[3]

There is almost no direct financing for SHP projects in Myanmar. Without collateral help, the local private banks cannot grant a loan for projects. Local SHP developers or specialists have to negotiate with rural community to agree on project funding and tariffs for implementing projects in off-grid areas. The village community usually raises funds together and the developer bears some of the upfront cost for the beginning of the project. During the last three years, the Department of Rural Development under the Ministry of Livestock, Fishery and Rural Development granted funds to develop 5 kW to 10 kW micro-hydropower projects in a limited number of villages with fixed budgets. There were several demonstration projects on SHP by some donor agencies such as JICA, GIZ, and others with small cost contributions from community subsidies and other incentives or financial support. Identifying and obtaining financial resources for SHP in Myanmar is very hard. Local SHP developers usually do not proceed with calculating the payback period of the project as they have limited capabilities to perform financial returns analysis.[10]

Renewable energy policy

Myanmar is in the process of setting up new energy infrastructure and has already made significant progress in improving access to new and renewable energy (RE) sources. A renewable energy policy is required to continue the progress, monitor changes and trends in the energy sector and develop mechanisms to address the new challenges efficiently. Further development of renewable energy will contribute to the national energy diversification and sustainable energy supply of the country.[9]

The overall renewable energy contribution to installed generation capacity (without large hydropower) is expected to reach 26.8 per cent or 3,995 MW by 2030, with off-grid hydropower with installed capacity of 198 MW accounting for 1.3 per cent (5 per cent of total).[9]

Power purchases through the feed-in tariff (FIT) system will be valid for 20 years from the date of the first connection. Tariff bonuses can also be granted during peak hours. FITs are determined based on the real generation cost and taking into account the macro-economic effect on electricity prices with variations for generators of different size and technology. However, all infrastructure costs, including connection and lines to the next suitable connection point, are borne by the developer.[9]

Rural electrification will still meet certain limitations in terms of quantity, quality and affordability but renewable energy can help overcome them when the private sector is considered as a partner. With cooperation of multiple partners, it is possible to achieve a substantial contribution to the overall target. Up to now, slow access growth has pushed rural citizens to develop and build engineer-like solutions of their own. Private companies and NGOs have already contributed to a large extent to the development of renewable energies in Myanmar. The major challenge they experience is collecting required funds to guarantee solid long-term profit. Additionally, clear planning and guidance on the part of the Government is required.[9]

An overall weakness of rural electrification development is service quality, compromised by sites remoteness and lack of local capacity building to maintain the production units. This applies to grid electrification as much as to off-grid models. But while grid operation has established maintenance routines, off-grid operation is often not well set up. Proper maintenance requires government supervision and a corresponding institutional set-up. Off-grid delivery models have been proven as reliable in many countries and can be applied in Myanmar as well. Capacity building on design and service will help provide reliability and good service to users.[9]

Legislation on small hydropower

There is limited legislation concerning any form of hydropower. Given the rapid developments occurring, there is a need to create a comprehensive framework for hydropower development. During the 5th Mekong Legal Network meeting of legal professionals from the six Mekong countries held in 2012 in Chiang Mai (Thailand), the legal challenges, reforms and opportunities in hydropower for lawyers and promoters working in Myanmar were discussed.[17] This small step is a significant move in the right direction.

Barriers to small hydropower development

Although the Government of Myanmar is working on the development of renewable energies, there are still challenges to cope with for the development of SHP projects.[10]

Financial barriers include:

- Lack of direct financial support from banks;
- Short allotted time frames for implementing projects;
- Fixed tender costs (by the Department of Rural Development);
- Financial burdens due to high costs for developers and low-income rural households.

Regulatory and institutional barriers:

- Lack of direct stakeholder involvement;
- Unclear regulatory procedure for connecting mini-hydropower plants to the grid;
- Lack of support for capacity building of private developers;
- Complicated procedure for project implementation;
- Difficulty to obtain necessary planning data and permits, which increases the risk of wrong planning;
- Better coordination is needed among the national and regional governments to help local needs and priorities to become integrated into the national framework.[9]

Technical barriers include:

- Limited technical knowledge, skills and operational experience impede performance;
- Lack of resource survey data;
- Hydropower projects require preliminary engineering and feasibility studies. This makes it difficult in rural contexts;
- Mini-hydropower plants usually generate electricity above the needs of single towns or villages;
- Small and mini-hydropower projects, except for home-use micro-hydro projects, require a basic level of maintenance. This requires coordination, capacity building and O and M training on operation and maintenance

The following recommendations and next steps will enhance the development of SHP projects:

- Create a central resource information centre, a capacity development and support structure to provide information on the energy sector in Myanmar, including existing opportunities, evaluate effectiveness and efficiency of alternative technologies.
- Promote public-private partnerships and dialogue, inter-ministerial cooperation as well as research, study.
- Organize a forum that will help Myanmar to better face the many policy, technical, social and other challenges presented by national and rural electrification.
- Support expansion of capacity building, training and development of human and institutional structures.[11]

3.4.6 Philippines

Darlene Arguelles, AboitizPower

Key facts

Population	106,400,000[1]
Area	300,000 km²
Climate	Tropical maritime climate that is generally hot and humid. There are three seasons: a hot dry season from March to May, a rainy season from June to November and a cool dry season from December to February. Temperatures usually range between 21°C and 32°C, although it can get cooler or hotter depending on the season. The coolest month is January while the warmest is May. Average annual temperature is approximately 26.6°C. Areas of higher altitude tend to be cooler such as in Baguio City where the average annual temperature is 18.3°C.[2]
Topography	The Philippines is an archipelago of 7,107 islands with a combined coastline of 36,289 km making it the fifth longest in the world. The highest mountain is Mount Apo reaching 2,954 metres, which is located on the island of Mindanao. Situated on the western fringes of the Pacific Ring of Fire, the Philippines experiences frequent seismic and volcanic activity.[3]
Rain pattern	Average annual precipitation is 2,348 mm, however, it ranges between 960 mm and 4,040 mm depending on the region. The south-west monsoon occurs from May to October and the north-east monsoon from November to April. Generally the east coasts receive heavier rainfall during November and December while the west coasts receive heavier rainfall during July and August.[2]
General dissipation of rivers and other water sources	The Philippines has 412 principal river basins in 119 proclaimed watersheds. Of these, 19 are considered major river basins. The longest river is the Cagayan River, which is approximately 500 km long with a basin of approximately 27,280 km². Laguna de Bay, 13 km south-east of Manila, is the largest lake of the Philippines with a surface area of approximately 949 km².[4]

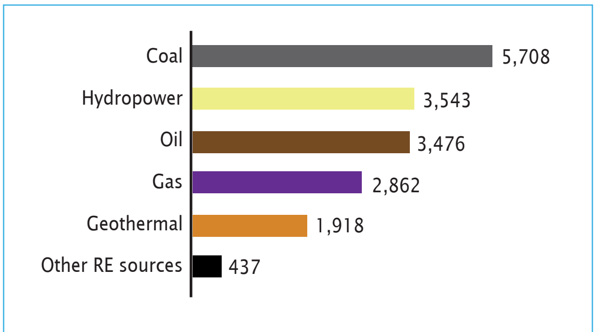
Electricity sector overview

In 2014 the Philippines had a total dependable capacity of 17,994 MW consisting of approximately 32 per cent from coal power plants, 20 per cent from hydropower plants, 19 per cent from oil plants, 16 per cent from natural gas and 11 per cent from geothermal plants. New renewable energy sources, including wind farms, solar photovoltaic and biomass power plants, had a total capacity of 437 MW or approximately 2 per cent (Figure 1). Approximately 68 per cent of the total installed capacity was from fossil fuel based power plants.[5]

In 2014, total generation was 77,261 GWh with almost 74 per cent from fossil fuel based power plants. Approximately 43 per cent came from coal, 24 per cent from gas and 7 per cent from oil. Geothermal energy contributed approximately 13 per cent while hydropower contributed 12 per cent. The contribution of new renewable sources was negligible (Figure 2). Although at the beginning of the twenty-first century renewable sources provided almost 40 per cent of the country's electricity, large increases in, first, gas power and more recently coal have reduced their share considerably (Figure 3).[5]

FIGURE 1

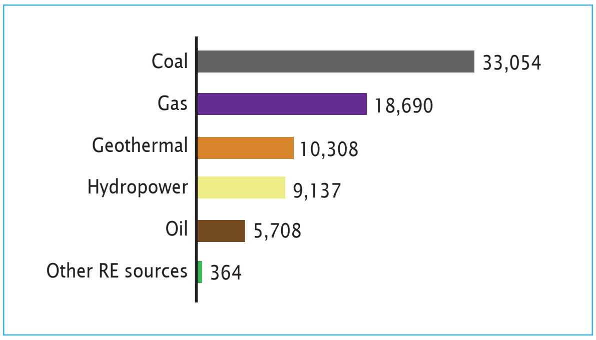
Installed electricity capacity in the Philippines by source (MW)



Source: Philippines Department of Energy[5]

FIGURE 2

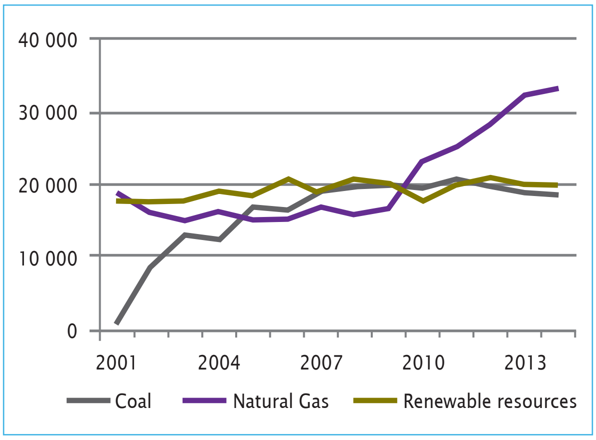
Electricity generation in the Philippines by source (GWh)



Source: Philippines Department of Energy[5]

FIGURE 3

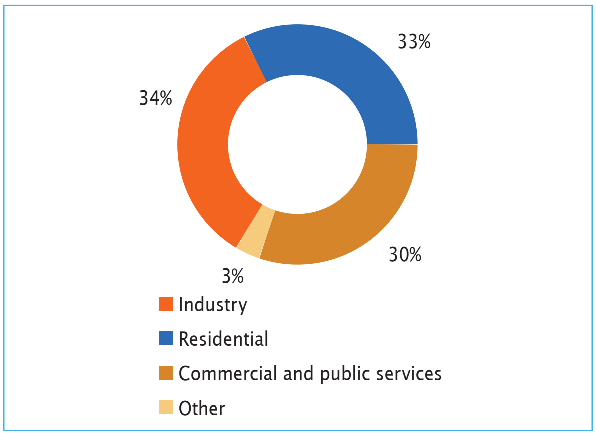
Electricity generation in the Philippines by source 2001-2014 (GWh)



Source: Philippines Department of Energy[5]

FIGURE 4

Electricity consumption in the Philippines by sector 2001-2014 (%)



Source: Philippines Department of Energy[5]

In 2014 the total consumption of 63,345 GWh was almost evenly distributed between industrial, residential and commercial sectors with 34 per cent, 33 per cent and 30 per cent shares respectively (Figure 4). Energy losses accounted for more than 9 per cent of total generation.[5]

In 2012 the national electrification rate was 87.5 per cent.[6] There is no data on rural electrification for the same year however the Philippine Institute for Development Studies estimated it at 73 per cent.[7] The Department of Energy, through its Rural Electrification Program and in coordination with the National Electrification Administration (NEA), aims to achieve 90 per cent electrification at the household level by 2017.[8]

Prior to 2001 the National Power Corporation (NPC) was responsible for constructing, operating and maintaining facilities for the production and transmission of electricity. In 2001, the Electric Power Industry Reform Act (EPIRA) was enacted to privatize NPC's assets and contracts with Independent Power Producers (IPP) to encourage an influx of private investments in the sector. This enabled the separation of the generation and transmission functions in the electricity sector. Through the EPIRA, the Wholesale Electricity Spot Market (WESM) was established in Luzon and Visayas for energy trading, where generation tariffs are driven by transparent and competitive market forces. The privatization of the electricity sector and the establishment of the WESM triggered improvements in the country's electricity infrastructure paving the way for retail competition and open access. The Philippines Department of Energy (PDOE) is responsible for preparing and coordinating government plans and activities relating to energy exploration, development and distribution.

The National Grid Corporation of the Philippines (NGCP) is responsible for overseeing the country's grid system. The transmission system of the country is divided into three main grids in Luzon, Visayas and Mindanao. The Luzon grid accounts for 73 per cent of total generation, Visayas 15 per cent and Mindanao 12 per cent.[9] The grid development is not nationwide however creating additional problems for potential power plants, particularly small hydropower (SHP), which can be located very far away from existing connections. Renewable energy developers must often invest heavily in long transmission systems to connect to the grid, which puts a burden on the initial investment, with additional permits and authorization required. The NGCP aims to address this issue through the Transmission Development Plan (TDP).

Power demand in the Philippines has seen an average annual growth rate of 4.5 per cent. Such growth must be sustained through capacity additions as supply constraints are becoming apparent. This is further aggravated by hydropower plants being unavailable during the hot dry months when demand is high, a problem especially evident in the Mindanao Grid where 43 per cent of the total capacity is sourced from hydropower.[10] To address this, private sector investments are being encouraged by the Government. The Republic Act No. 9513 or the Renewable Energy Law (REL) specifically aims to accelerate the development, construction, and operation of renewable energy plants as one of the responses to energy security and independence to imported fuel utilized for conventional power plants (see below).

TABLE 1

Average electricity price by customer type and region

Customer type	Average price (Philippine Pesos (US$) per kWh)			
	Luzon	Visayas	Mindanao	Overall average
Residential	7.70 (0.179)	5.87 (0.136)	4.58 (0.106)	7.10 (0.165)
Commercial	7.57 (0.176)	6.04 (0.140)	4.81 (0.112)	7.26 (0.168)
Industrial	6.70 (0.155)	5.82 (0.135)	4.59 (0.106)	6.29 (0.146)
Others	7.05 (0.164)	5.87 (0.136)	5.11 (0.119)	6.19 (0.144)

Source: PDOE[11]

Other than competitive rates brought about by the establishment of the WESM, electricity rates are regulated. The Energy Regulatory Commission (ERC) ensures the compliance of rules, resolutions and decisions by the electric power industry participants. The ERC also decides on the electricity tariff to be implemented between an electricity generation company and an electricity distribution utility through a bilateral supply contract. Table 1 provides average electricity prices according to customer type and region.

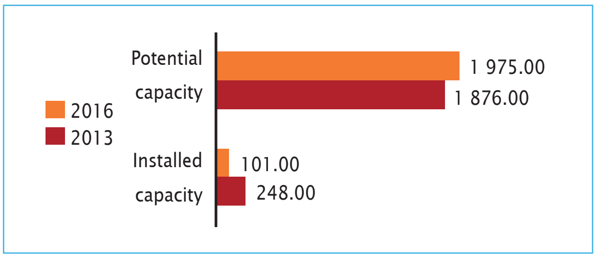
Small hydropower sector overview and potential

Plants with an installed capacity of 10 MW or less are defined as mini-hydropower with micro-hydropower defined as between 1 kW and 100 kW. For the purposes of this report all hydropower up to 10 MW is defined as small.

Total installed capacity for SHP plants is 101 MW with a total estimated potential of 1,874 MW indicating that approximately 5.4 per cent has been developed. Compared to data from the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, while the total potential remains approximately the same, installed capacity has decreased (Figure 5).[12]

FIGURE 5

SHP capacities 2013-2016 in the Philippines (MW)



Sources: Philippines Department of Energy,[12] *WSHPDR 2013*[13]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The Philippines has a total hydropower capacity of 3,521 MW, of which SHP plants of below 10 MW account for approximately 3 per cent. The total untapped hydropower potential of the country is estimated at 13,097 MW, of which 85 per cent is from sites with an installed capacity above 10 MW (11,223 MW), 14 per cent (1,847 MW) from sites between 101 kW and 10 MW with less than 1 per cent (27 MW) from sites between 1 and 100 kW.

As of 31 August 2015, there were 319 SHP projects of 10 MW or less approved by the PDOE with a total potential capacity of 1,186 MW and 124 projects with a total potential capacity of 535 MW pending applications.[14,15] This suggests that of the total untapped potential capacity of 1,874 MW, almost 92 per cent has been approved or is pending approval. The PDOE aims to increase hydropower capacity by 160 per cent by 2030.

Renewable energy policy

The Republic Act No 9513, otherwise known as the Renewable Energy Law (REL), was passed in 2008. The REL aims to accelerate the exploration and development of renewable energy resources to achieve energy self-reliance, and to reduce the country's dependence on fossil fuels that would minimize the country's exposure to price fluctuations in the international markets. As of 31 August 2015, a total of 682 renewable energy (solar, wind, hydro, geothermal, ocean, biomass) projects across the country were endorsed by the Department of Energy with a total potential capacity of 13,575 MW.[16]

Through the REL, the National Renewable Energy Program (NREP) was established in order to outline the country's long-term path to developing its renewable energy potential. The ultimate goal is to increase the renewable energy generating capacity to 15,304 MW by 2030. The following objectives are laid out under the NREP:

- Increase geothermal power capacity by 75 per cent;
- Increase hydropower capacity by 160 per cent;
- Increase biomass power capacity by 277 MW;
- Increase wind power capacity by 2,345 MW;
- Increase solar power capacity by 1,528 MW;

For renewable energy projects such as solar, intermittent hydropower, biomass, wind and tidal registered through the REL and connected to the grid, feed-in tariffs (FITs) are pre-determined and approved by the ERC (Table 2). The FIT is a fixed tariff available to qualified renewable energy projects for a period of at least 12 years.[17,18,19]

TABLE 2

Renewable energy FITs by source

Plant type	FIT (Philippine Peso (US$) per kWh)
Run-of-river hydropower	5.90 (0.136)
Wind	8.53 (0.196)
Biomass	6.63 (0.152)
Solar	8.69 (0.200)

Source: Various[16,17,18]

Developers of renewable energy can also benefit from fiscal incentives provided by the REL including:

- Seven years Income Tax Holiday (ITH);
- Ten year duty-free importation of renewable energy machinery, equipment, and materials;
- 1.5 per cent special realty tax rates on equipment and machinery;
- Seven years net operating loss carry-over;
- 10 per cent corporate tax rate after ITH;
- Accelerated depreciation;
- 0 per cent VAT;
- Tax exemption on carbon credits;

- 100 per cent tax credit on domestic capital equipment and services;
- Exemption from the Universal Charge;
- Government share at 1 per cent of the gross income of renewable energy developers.

Lending banks are also becoming more receptive of renewable energy project financing due to the positive reputation and social acceptance it brings. Banks known to offer renewable project financing include: Banco de Oro (BDO), Bank of the Philippine Islands (BPI), Philippine National Bank (PNB) and the Development Bank of the Philippines (DBP).

Legislation on small hydropower

In 1991, the re-established democratic Congress enacted the mini-hydropower Incentives Act (Republic Act 7156), limiting incentives to run-of-river plants, defined as those utilizing the 'kinetic energy of falling or running water', and those with capacity ranges from 101 kW to 10 MW.[20]

Barriers to small hydropower development

The main barriers to SHP development are access to the grid and the number of regulatory agencies making it difficult to gain permits. The most significant barrier to the acquisition of Government endorsements, approvals or certificates is the long processes involving obtaining approvals from more than 30 Government agencies, and more than 80 permits to acquire. This problem is further complicated by uncoordinated processes between agencies resulting in further project development delays. The approval process is disproportionately expensive for SHP development translating into significant risk for developers and investors.

Currently the PDOE has pending and awarded hydropower projects with a total of 10,456 MW however, only a total of 26.6 MW of these projects are approved under the FIT system. This is largely due to the bureaucracy involved in issuing government endorsements, approvals and certificates.

For renewable energy, particularly hydropower, accessibility and connection to the grid have proven to be financially and technologically difficult. The construction of extensive transmission lines can make a project financially unattractive and will also depend on the timeline of the Transmission Development Plan (TDP) of the NGCP. The NGCP is preparing for the variable renewable energy plants as a result of the REL, however, the challenge for this bulk entry is that such technologies are location specific. Apart from the grid development relative to the TDP, NGCP must also consider the provision of ancillary services to manage the net variability of the grid resulting from the entry of renewable energy. In the context of grid reliability, NGCP is conducting studies to determine the maximum penetration limit of variable renewable energy considering the availability of regulating reserves. This becomes a potential barrier not only to SHP development, but to all variable renewable energy technologies as well.

Additionally, there is a lack of social and community acceptance with some communities that have rejected any form of utilization of the rivers within their area or have demanded compensation or royalties.

3.4.7 Thailand

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Key facts

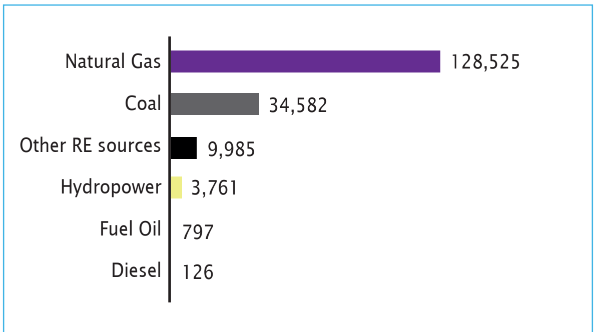
Population	65,104,000[1]
Area	513,120 km[2]
Climate	Tropical monsoon, generally hot and humid across the country most of the year. The climate can be classified into three seasons: hot season (from March to May), rainy season (from May to October) and cold season (from November to February). The temperature ranges between 24 °C and 30 °C.[2]
Topography	Mountains cover most of the northern Thailand and extend along the border with Myanmar down through the Kra Isthmus and the Malay Peninsula with the highest point being Doi Inthanon mountain at 2,565 metres. The central area is made of lowlands dominated by the Chao Phraya River Basin.
Rain pattern	Average annual rainfall is 1,622 mm, ranging from 1,020 mm in the north-east to 3,800 mm on the peninsula. About 80 per cent of the total annual rainfall occurs from May to October.[2]
General dissipation of rivers and other water sources	Thailand is divided into 25 major river basins. Four major rivers originating from the north are Wang, Ping, Yom and Nan, which confluence to become the Chao Phraya River. Whereas, water from rivers like Chi, Mun and Songkhram drain to the Mekong River.[3]

Electricity sector overview

The major sources of electricity in Thailand are natural gas followed by coal and lignite. Hydropower contributes only 2.9 per cent of the total power produced (Figure 1).

FIGURE 1

Electricity generation by sources in Thailand (GWh)



Source: Ministry of Energy[4]

A state enterprise, Electricity Generation Authority of Thailand (EGAT) under the Ministry of Energy is the main authority responsible for production and transmission of electric power throughout the country. As of 2015, the total installed capacity of Thailand was 38,815 MW, of which 40 per cent was produced by EGAT's power plants. The remaining 60 per cent were purchased from other domestic power plants including Independent Power Producers (IPPs), Small Power Producers (SPPs), Very Small Power Producers (VSPPs) and imported from neighbouring countries.[5] EGAT has the total transformer capacity of 91,211 MVA with total transmission length of 32,960 circuit-km.[5] The electrification rate of the country is 99 per cent, with a 100 per cent rate of urban electrification and 99 per cent rate of rural electrification.[6]

EGAT has the sole right to buy electricity from private power producers and neighbouring countries and sells wholesale electricity energy to two distributors: Metropolitan Electricity Authority (MEA), which supplies electricity to Bangkok, Nonthaburi and Samut Prakran, and Provincial Electricity Authority (PEA), which supplies electricity to the rest of Thailand.[7]

Most of the hydropower plants are operated in rural and remote areas of Thailand. Around 75 micro hydropower plants with combined capacity of 2.49 MW are installed to directly provide electricity to the communities that are not connected to the grid.[8] In addition 32 small hydropower (SHP) plants (up to 10 MW) are planned to be installed by 2030.[9]

With increases in GDP and population, the electricity demand in Thailand is increasing every year. It is forecasted that the peak energy demand for 2030 will reach 52,256 MW, which is 35 per cent higher than the country's installed capacity as of 2015.[9] Therefore, from 2012 to 2030 the Government plans to increase its capacity by 55,130 MW, out of which 6,572 MW will be purchased from neighbouring countries like Myanmar, Laos and Cambodia.[9] This will bring the total generating capacity to 70,686 MW deducting decommissioned power plants.[8,9]

The Energy Regulatory Commission (ERC) is responsible for adjusting tariffs, which are uniform in all regions of the country in both MEA and PEA distribution networks.[7] The electricity tariff rate comprises two parts: (a) a base tariff that reflects the construction costs of power plants, transmission and distribution system, fuel and operation and maintenance costs; and (b) automatic tariff adjustment (Ft) to compensate for inflation and exchange rate fluctuation at international markets for fuel and power purchases. Ft is adjusted every four months. In addition, a VAT of 7 per cent is added to the base tariff and Ft. The electricity tariff rate varies for different sectors with an increasing block rate method. The tariff also varies according to the voltage level and consumption time (peak and off-peak hours).[10]

TABLE 1

Residential tariff (rate per kWh)

Monthly consumption	Monthly tariff (per kWh)	
	Baht	US$
Consumption not exceeding 150 kWh per month:		
First 15 kWh (0 – 15th)	1.86	0.06
Next 10 kWh (16th-25th)	2.50	0.08
Next 10 kWh (26th-35th)	2.75	0.09
Next 65 kWh (36th-100th)	3.14	0.1
Next 50 kWh (101st-150th)	3.23	0.1
Next 250 kWh (151st-400th)	3.74	0.12
Over 400 kWh (401st and over)	3.94	0.13

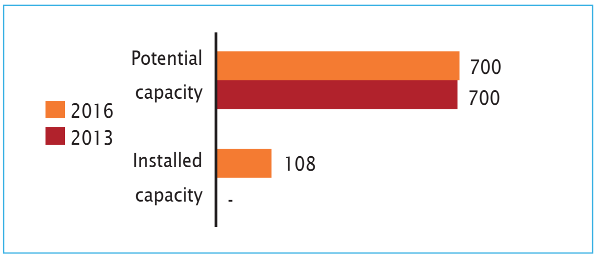
Source: Energy Regulatory Commission[21]

Small hydropower sector overview and potential

Based on production, hydropower in Thailand can be divided into micro hydropower (below 200 kW), small/mini (200-6,000 kW), medium (6,000-20,000 kW) and large (above 20,000 kW).[8]

FIGURE 2

SHP capacities up to 6 MW 2013-2016 in Thailand (MW)



Sources: Ministry of Energy,19 WSHPDR 201316
Note: The comparison is between data from WSHPDR 2013 and WSHPDR 2016. The 2013 report cited SHP installed capacity of 146 MW (up to 15 MW SHP definition).

The SHP installed capacity up to 6 MW was 108 MW as of 2014.[19] It should be noted that a different definition was used in the previous report therefore a comparison would not be accurate. Potential for SHP varies per estimate, however the range is between 700 and 1,100 MW.[8,11]

The northern part of Thailand has most of the potential for SHP development. As of 2015, there were 41 SHP plants with the total capacity of 108 MW connected to the national grid.[8] Additionally, 256 sites have been identified for development of small and medium hydropower plants.[8] Around 2.25 per cent of the total electricity produced by hydropower is generated from SHP plants.[8]

TABLE 2

Installed SHP capacity in Thailand (MW)

Type	Entities	Total capacity (MW)
SPP	EGAT	37.8
SPP	Dept of Alternative Energy Development and Efficiency	12.2
VSPP	DEDE / PEA	58

Source: Ministry of Energy (2014)[18]

TABLE 3

Planned small and medium hydropower (MW)

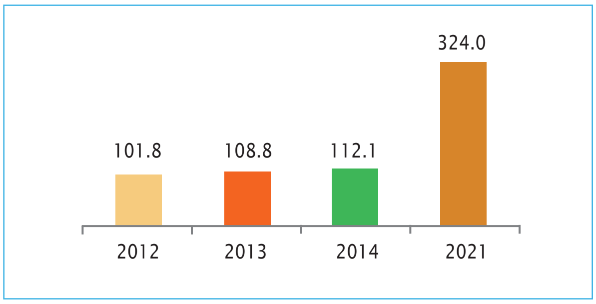
Name	Region	Potential (MW)	Scheduled commercial operation
Naresuan Hydropower Plant	—	8*	2014
Khun Dan Prakanchol Dam	Nakhon Nayok	10	2015
Mae Klong Dam	Kanchanaburi	12	2015
Pasak Jolasid Dam	Lop Buri	6.7	2015
Kiew Komah Dam	Lampang	5.5	2015
Klong Tron Dam	Uttaradit	2.5	2018
Chulabhorn Hydro Plant	Chaiyaphum	1.25	2018

Source: Electricity Generating Authority of Thailand[20]
Note: An asterisk (*) indicates the plant should be operational.

The Government policy encourages the private sector to participate 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) are some of the policies supporting private investment in the energy sector. In 2012, 152 MW of renewable energy (RE) was produced by the private sector with a total project cost of US$294 million and further projects equivalent to 340 MW are under construction.[12] However, none of them were SHP projects.

FIGURE 3

Expected SHP (<6 MW) development by 2021 (MW)



Source: Ministry of Energy[19]
Note: Projected data for 2014.

Under the Alternative Energy Development Plan 2012 – 2021, which was still the applied policy in 2015, the road map calls for 25 per cent of RE in total consumption by 2021. The plan indicates that SHP will increase significantly, in particular the number of plants with below 1 MW of installed capacity will reach 324 MW (Figure 3).[19]

Renewable energy policy

The main objective of the Thailand Power Development Plan 2010-2030 (PDP 2010) is to focus on security and adequacy of power systems along with promoting energy efficiency and renewable energy. The PDP 2010 has the following energy policies regarding electricity development:

- The 20-Year Energy Efficiency Development Plan 2011-2030 (EE Plan 2011-2030) promotes energy conservation by reducing the ratio of energy use to productivity by 25 per cent by 2030.
- The Alternate Energy Development Plan 2012-2021 (AEDP 2012-2021) foresees an increase in the share of renewable energy and alternate energy use by 25 per cent by 2021.[9]

The Government of Thailand plans to increase its renewable energy capacity by 14,580.4 MW, out of which SHP will represent only 0.71 per cent. The development strategies to reach these goals include:

- Promoting community collaboration in order to broaden production and consumption of renewable energy;
- Generating off-grid hydropower at the village level for non-electrified households;
- Supporting hydropower projects at the community level by allowing local administration and people to collaborate as project owners;
- Amending laws and regulations that do not benefit renewable energy development;
- Assigning Department of Alternative Energy Development and Efficiency (DEDE) and EGAT to develop SHP systems on downstream irrigation dams and mini hydropower systems at generation capacities of 200 to 6,000 kW;
- Disseminating and conducting public relations on information and advantages of hydropower projects.
- Promoting research on run-of-river micro hydropower turbines and studying and developing low-head turbine types.[13]

To promote and support the utilization of alternate energy, the Ministry of Energy will provide feed-in tariffs (FITs) in replacement of adder rate payment to VSPPs.[14] FITs are provided for a 20-year term to all forms of renewable energy except for the landfill, which is eligible for only 10 years. This will provide financial certainty over a period twice as long as with adder rate payment for some projects.[14] The rates are determined based on types of renewable energy, installation location and installation capacities. For hydropower projects the FIT rate is THB 4.9 (US$0.14) per kWh for a 20-year period. Projects located in Yala, Pattani, Narathiwat and 4 sub districts of Songkla (Jana, Tepha, Sabayoi and Natawee) will get THB 0.50 (US$0.01) per kWh for the lifetime of the project.[14]

Legislation on small hydropower

With regards to SHP, in 2002, Thailand introduced the supportive VSPPs policy for installations with capacities not greater than 1 MW. VSPPs are private power producers with a generating capacity of below 10 MW that sell electricity to MEA or PEA. The policy is also applicable to renewable technologies and other non-conventional resources (i.e. waste, agricultural residues, biomass and solar energy), as well as Combined Heat and Power (CHP) and Cogeneration systems.[17]

In September 2006, the policy was altered in order to encompass projects generating 1-10 MW, i.e. Small Power Producers (SPPs).[17]

Barriers to small hydropower development

Legal provisions are the main obstacle for SHP development in the northern region of Thailand.[15] Most of these potential hydropower sites are located in the forested areas with legal limitations due to protection policies. The Forest Act (1941), National Park Act (1955), National Reservation and Protection Act (1992) and National Reserved Forest Act (1964) restrict the development of hydropower. However, projects can be done within the conserved area if the benefit of the project goes to the national park only.[15] Similarly, the Cabinet resolution of 15 May 1990 restricts the use of conservation areas by private agencies.[15] These kinds of policies undermine the growth of SHP. Updated policies with provision of the right of ownership and selling of excess electricity would attract private investors and contribute to the development of SHP as well as the national grid.

3.4.8 Timor-Leste

Kassius Klei Ximenes, The National Electrification Project

Key facts

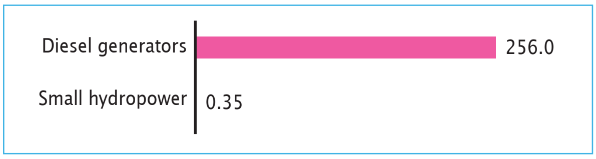
Population	1,212,107[6]
Area	15,410 km^2
Climate	Tropical hot and humid climate. The wet season is from December to March whereas the dry season lasts from May to October. The temperatures average 30°C all year round with cooler temperatures in higher altitude areas reaching 14°C at 2,000 metres.[7]
Topography	The inland of Timor-Leste is mountainous with its highest peak being Foho Tatamailau at 2,963 metres. Both the northern and southern parts are made of highlands while the north also has lowlands; coastal areas are at sea level.[7]
Rain pattern	Average annual rainfall is 1,500 mm, whereas the central mountainous region can receive up to 2,837 mm and almost no rain falls during the dry season in the northern part of the country,[7]
General dissipation of rivers and other water sources	The largest river system is the Loes River basin with a total area of 2,184 km^2 covering almost 15 per cent of the country. It is also the longest river (80 km long), followed by the Laclo River system and the Clere and Belulic River system with 2,024 km^2 and 1,917 km^2 respectively. Given the temporal variations in rainfall and the low capacity of upland areas to hold water, very few rivers flow all year round.[7]

Electricity sector overview

As of 2014, installed capacity in Timor-Leste was 256.35 MW and generation reached 348 GWh.[3,10] Diesel generators operating on imported fuel provide the main source of electricity, with a small amount contributed by small hydropower (SHP) (Figure 1). Plans are underway to expand and diversify generation, to include renewable resources.[3,9]

FIGURE 1

Installed electricity capacity in Timor-Leste (MW)



Sources: Final Hydropower Master Plan,[3] IJHD,[9] General Directorate of Statistics[10]

The public utility Electricidade de Timor-Leste (EdTL) under the Ministry of Public Works, Transportation and Communication is the agency responsible for generation and distribution of electricity.

Since 2007, the Government has greatly improved the electric network. While the national grid is still not in place, 150 kV transmission lines have been installed for major load centres; separate loop systems operating on 20 kV lines have been extended throughout parts of the country on 57 isolated grids serving 17,000 consumers.[1,9] The largest systems are in the urban centres, including the capital Dili, as well as Baucau but outages are still frequent. The three major generation locations are in Hera, Betano and Comoro representing most of the installed capacity of the country.

In accordance with the Electrification Program for Oeccusse Island (Enclave), the Government has invested in a diesel and natural gas power plant with an installed capacity of 17.3 MW (four of 4.3 MW), which was planned to be operational by the end of 2015. The Electrification Plan for Atauro Island will combine a hybrid system with the existing 500 kW diesel power plant to expand the supply of electricity in Atauro.

The National Strategic Development Plan 2030 states that all Timorese should have quality access to electricity by 2017. The Government plans to diversify energy resources for the electricity sector through solar, hydro, wind and biomass energy. Business modules for the electricity sector have been planned to go to private-public partnership (PPP). The Government plans to drastically overhaul the energy sector by switching to hydropower generation as the base load production and the existing conventional energy plants will serve for peak and base loads. On Atauro Island, it is planned to use solar energy (through solar roofing methods and storage) for base load and the existing diesel generator for peak load.

The current electrification rate in Timor-Leste is 75 per cent. The Government states that about one-third of the population has access to electricity, generally for six hours per day.[1]

The current tariff for electric consumption ranges from US$0.12 to US$0.22 per kWh. The lower prices are for the residential and social sectors, and the rates have not changed since 2002. The price of electricity is considered a national rate and does not vary among regions, energy resources or demand side management issues.

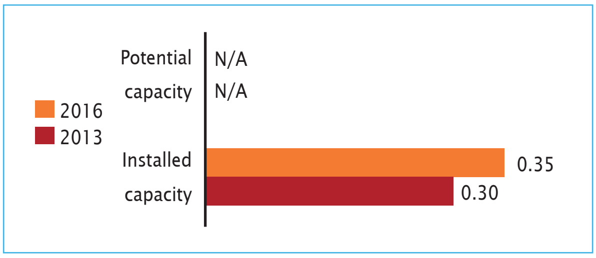
The main challenge existing in the electricity sector of Timor-Leste is the lack of a comprehensive energy framework, which should include electric policies and economic incentives.

Small hydropower sector overview and potential

In Timor-Leste, the definition of SHP is an installed capacity of up to 50 MW. The installed capacity of SHP is 0.352 MW and the potential is unknown.[3] Between the *World Small Hydropower Development Reports* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has remained roughly the same while potential remains unknown (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Timor-Leste (MW)



Sources: *WSHPDR 2013*,[8] Final Hydropower Master Plan 2012[3]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The potential of hydropower resources was explored from 2003 to 2006 through institutional cooperation between the Government of Timor-Leste and The Royal Kingdom of Norway. The Timor-Leste State Secretary for Energy Policy and the Norwegian Water Resources and Energy Directorate were involved in the development of the Hydropower Master Plan for Timor-Leste for which 23 hydropower projects were studied: 6 large, 16 small and 1 micro. The Plan was expected to be implemented in 2012. It is still expected to become an important tool for sustainable development of hydropower resources in Timor-Leste. The total hydropower potential of Timor-Leste is approximately 235 MW, with a potential annual production of 812.8 GWh. From an economic point of view among these 23 locations at least 15 locations are viable (with a potential capacity of 187.6 MW and electricity generation of 670.6 GWh). The specific SHP potential is unknown.[3]

There are three SHP plants in Timor-Leste: Gariuai in Bacau (326 kW), Taossu in the Viqueque district (15 kW) and a micro hydropower plant in the Ainaro district (12 kW). The two SHP plants are not in operation due to technical issues.[1]

An earlier analysis of potential hydropower sites in Timor-Leste identified nearly 40 promising sites that could generate between 1.2 MW and 50 MW. Based on these results, detailed research and analysis including feasibility studies will be conducted on potential mini hydropower sites throughout the country. The majority of mini hydropower projects are reported to have enough water for operation in the wet season only. Yet, construction and operation of these plants is still expected to be economically worthwhile due to savings on the import of fuel. Furthermore construction activity creates jobs, and potential crossover benefits for agriculture also are expected.

Renewable energy policy

In 2009, the Secretariat of State for Energetic Policy launched a renewable energy programme covering biogas, solar, biodiesel, hydropower and wind. No investments in wind power have been made yet, however, this sector is to be developed as well according to the plan. The Government aims to provide 80 per cent of the population with access to electricity by 2025. Moreover, the country expects to meet half of its energy needs from renewable energy sources as per the National Strategic Development Plan 2011-2030. According to a comprehensive estimate of the country's renewable energy resources by the Portuguese company Martifer, apart from hydropower, Timor-Leste has 72 MW of wind power potential, 22 MW of solar power potential and 6 MW of biomass and solid waste potential.[8]

The Government also predicts the establishment of wind and hydropower hybrid systems with hydropower to be used in the rainy season and fuel or biogas during the drier period.

In 2010 the Secretariat of State for Energy Policy drafted the Basic Law for Renewable Energies, however, as of 2014 it was not ratified.[11] The law foresees creation of a fund for the development of renewable energy and mechanisms for the country's RE resources as well human resource training, It also establishes a limit of 2 kW for electricity generation by community power plants, so that the generated electricity would be would be for the community's consumption only with the excess being sold to the national grid.[12]

To date, most of the renewable energy projects are being implemented by international donors as well as local and international NGOs, however, are very small-scale compared with the national energetic programme.

Barriers to small hydropower development

There is a lack of cooperation between the Government, universities, research institutes and NGOs that could help secure the country's sustainable development. Moreover, with improved monitoring and evaluation mechanisms it would be possible to identify best practices and replicate or scale up successful.[6]

It is important to provide capacity building at the community level, including promoting knowledge and experience sharing, developing management and other skills.

Other significant barriers are:

- Property rights are unclear;
- Customary laws that deal with marine and natural resources are not defined;
- Technical difficulties due to mountainous topography of the country;
- High cost of developing renewable technologies;
- Installed electricity meters in cities are often bypassed, leading to a numerous thefts of electricity and low income to cover project investment.

3.4.9 Viet Nam

Le Anh Tuan, CanTho University; Nguy Thi Khanh, Green Innovation and Development Centre

Key facts

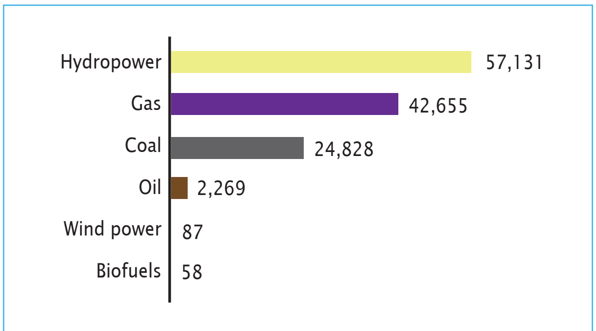
Population	90,728,900[1]
Area	330,972 km^2 [1]
Climate	Viet Nam is a long, narrow country with climate varying considerably from north to south. The northern regions experience a humid and subtropical climate, whereas the south is exposed to a tropical climate. In the north, seasonal variations are more distinct, with temperatures ranging from 15-20°C in winter to 22-27°C in summer. In the south temperatures remain around 26-29°C throughout the year.[4]
Topography	The general terrain elevation declines from the north-west to the south-east with almost all the rivers in Viet Nam following that direction. Mountains and hills occupy three-quarters of the territory; however, about 85 per cent among them are below 500 metres above sea level. The highest point is Fan Si Pan in the northwest of the country at 3,143 metres above sea level.[5]
Rain pattern	Most rainfall is caused by monsoon, which brings heavy rains from May to October in the north and the south; and from September to January in the central parts of the country. Average annual precipitation is around 1,800 mm. The average air humidity is over 80 per cent.[5]
General dissipation of rivers and other water sources	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 km and 220 km respectively. The total length of all rivers in Viet Nam is 41,000 km with a total flow of nearly 300 billion m^3 of water per year.[5]

Electricity sector overview

Electricity generation in 2013 was 127,028 GWh, consisting of hydro (44 per cent), gas (33 per cent), coal (19 per cent), oil (1.7 per cent), wind and biofuels (0.1 per cent). The country also imported 2,821 GWh and exported 1,290 GWh, totalling the domestic supply at 128,559 GWh (Figure 1).[2]

FIGURE 1

Electricity generation in Viet Nam (GWh)



Source: IEA[2]

In 2014, the total installed capacity of power plants in Viet Nam was 34,080 MW. The amount of electricity produced the same year was estimated at 145,500 GWh, which was 2.7 times more than in 2005 and 1.7 times more than in 2009. Hydropower dominates the power generation mix with a total installed capacity of 15,703 MW, accounting for 54 per cent of the country's total generation capacity. For over two decades, Viet Nam has rapidly built many hydropower plants around the midlands of the northern mountains, the central highlands and the south-eastern regions.[6] However, the share of hydropower is expected to decrease to 28.7 per cent by 2020 and to 17.8 per cent by 2030. On the contrary, the share of coal is expected to grow up to 50 per cent by 2030.[3]

Although Viet Nam has significant energy resources, including coal, natural gas and hydro, to meet its electricity demand the country has to export energy with exports growing at about 9 per cent annually.[3] During 2005-2014, the country's electricity demand grew by approximately 12 per cent, increasing from 45,600 GWh to 128,400 GWh.[3] In order to meet this growing electricity demand, it is planned to further develop the national grid, which includes developing additional transmission lines and creating new power plants by 2020.[7]

According to the Power Master Plan VII for 2011-2020 with the vision to 2030, the key directions of the country's energy development are: ensuring national energy security, supplying sufficient and high-quality energy for socioeconomic development, using and managing primary domestic energy resources efficiently, diversifying energy investments, establishing a competitive energy market, promoting new and renewable energy sources, and ensuring sustainable development.[3] Realization of this plan includes four practical targets:

- To increase the aggregate output of imported and produced electricity to approximately 330-362 TWh by 2020 and to 695-834 TWh by 2030;
- To increase the share of renewable energy sources to 4.5 per cent in 2020 and to 6 per cent in 2030;
- To reduce the average elasticity ratio of energy production to 1.0 in 2020;
- To reach almost 100 per cent rural electrification by 2020.[8]

Vietnam has already made outstanding progress in electrification with approximately 98.6 per cent of the population having access to electricity compared with 50 per cent in 1995.[3]

The state remains the main actor in the electricity sector with the state-owned Electricity Corporation of Viet Nam (EVN) owning about 22 per cent of the country's total installed capacity. The country also has three subsidiary generation companies (GENCOs) owning 39 per cent of the electricity sector, and state-owned companies PetroVietnam and Vinacomin owning 16 per cent. The remaining 23 per cent is owned by the private sector.[3]

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. As of March 2015, the average electricity retail tariff was VND 1,622/kWh (US$0.07/kWh).[3]

The country's electric system is operated at high voltage of 110 kV, 220 kV and 500 kV; and a medium voltage of 6 kV to 35 kV, which is integrated to 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.[12]

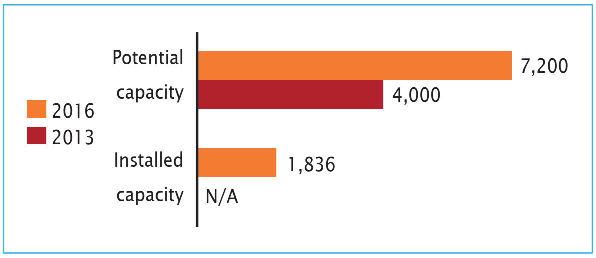
Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Viet Nam is up to 30 MW (as per Decision of Ministry of Industry – No 3454/QD-BCN dated 18 October 2005). Due to its dense river and stream systems, the country has a great SHP potential, which is estimated at 7,200 MW.[3] As of 2015, installed capacity of SHP of up to 30 MW per plant was at least 1,836 MW.[18] A comparison with the *World Small Hydropower Development Report* (*WSHPDR*) *2013* for SHP plants of up to 30 MW is shown in Figure 2. It should be noted that a comparison of installed capacity will not be given as the previous report cited data for a 10 MW or less definition of SHP. However, Figure 3 demonstrates SHP development since that period.

SHP plants are 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.[9]

FIGURE 2

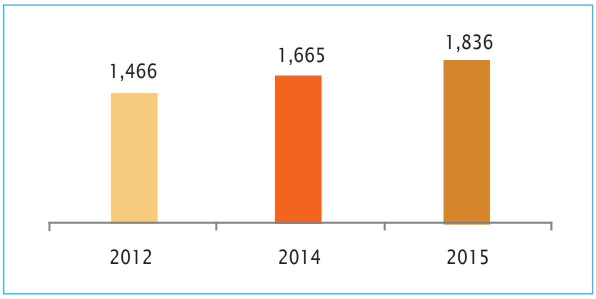
SHP capacities of up to 30 MW 2013-2016 in Viet Nam (MW)



Sources: *WSHPDR 2013*,[6] Asian Development Bank,[3] Electricity of Vietnam[18]
Note: Data in 2013 report (up to 10 MW) was 621.7 MW installed and 2,205 MW potential. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

FIGURE 3

SHP (< 30 MW) installed capacity in Viet Nam (MW)



Sources: World Bank,[19] ESMAP,[20] EVN[18]

TABLE 1

SHP projects cancelled as of April 2013

Reason	No. of projects	Installed capacity (MW)
Absence of project developers	206	391.9
Low economic value	31	100.7
Environmental and land acquisition issues	16	83.3
Nature reserves	8	34.1
Difficult grid connection	10	24.8
Downstream impact	7	26.2
Others	17	75.0
Cancelled before 2013	41	234.9

Source: Industrial Decisions, Inc.[21]

SHP remains the main sources of renewable energy in the country. Over a decade the number of SHP plants in the country increased dramatically, in particular due to a high flow of private investments. However, the lack of expertise and violation of agreements on the part of some developers have resulted in floods, dam breaks, earthquakes, forest loss and environmental degradation.[11] This pushed the Government to cancel multiple planned SHP projects including those already under construction. In October 2013, 418 projects with a total capacity of 1,174 MW were removed from the country's hydraulic development plan (Table 1).[21] The Government is planning to strengthen oversight on hydropower projects, especially small-scale ones.

Renewable energy policy

Viet Nam has high potential for the development of renewable energy sources such as solar, hydro, wind and biomass. Promotion of new and renewable energy sources is one of the objectives of the country's national energy development strategy 2020. The goal is to increase the capacity of wind power to approximately 1,000 MW by 2020 and 6,200 MW by 2030; biomass to 500 MW by 2020 and 2,000 MW by 2030; and hydropower to 17,400 MW by 2020. With hydropower, particular attention will be paid to multipurpose projects combining flood control, water supply and power production.[8]

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. There are also three feed-in-tariffs (FITs) in place for grid-connected renewable energy projects, namely for wind, biomass and solid waste. A FIT for solar energy is under consideration.[3]

Legislation on small hydropower

Relevant laws and regulations for renewable energy are:

- Law on Electricity dated 14 December 2004;
- Decision No. 1208/QD-TTg – The National Power Development Plan 2011-2020 with aims to reach development goals by 2030 (Master Plan VII), dated 21 July 2011;
- Decision 1855/QD-TTg Development Strategy of Energy's National Renewable Viet Nam 2020 vision in 2050 dated 27 December 2007.

Barriers to small hydropower development

While the country has developed more than 1,800 MW of SHP the main barriers for continued SHP development in Viet Nam are:

- Lack of a strong institutional and regulatory framework;
- Lack of technical capacity;
- High environmental and social risks;
- Low return on investment;
- Poor quality and safety control.

3.5 Western Asia

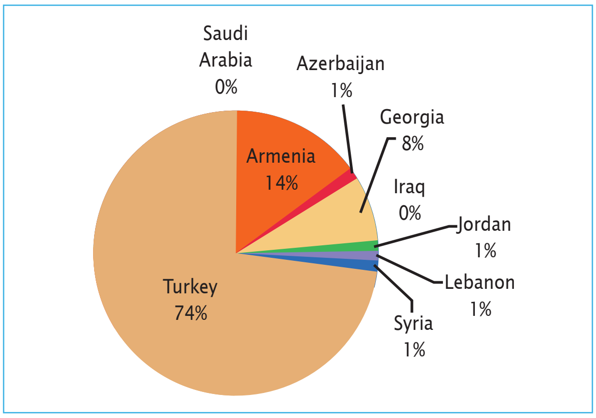
Kemal Baris, Bulent Ecevit University; Serhat Kucukali, Cankaya University

Introduction to the region

Western Asia comprises 18 countries. Diverse ecosystems are present within the region: the Mediterranean sub-region (Cyprus, Israel and Turkey), the Mashriq sub-region, which is Mediterranean humid to semi-arid (Iraq, Jordan, Lebanon, Syrian Arab Republic and the State of Palestine), the Arabian Peninsula (Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, the United Arab Emirates and Yemen), and the mountainous Caucasus region (Armenia, Azerbaijan and Georgia). Among these countries, eight have significant hydropower potential: Armenia, Azerbaijan, Georgia, Iraq, Jordan, Lebanon, Syria and Turkey. Israel and Cyprus may have some hydropower potential, with some hydropower capacities already installed, at 7 MW and 1 MW respectively.[10,11] However, security concerns in the countries have slowed the adaption processes.[12,13] Therefore, the present report covers these nine countries, including Saudi Arabia. Syria and Saudi Arabia were not covered in the *World Small Hydropower Development Report* (*WSHPDR*) *2013*. Saudi Arabia, in particular, does not have installed hydropower but it is the world's 20th largest producer and consumer of electricity and has abundant wind and solar renewable energy resources. This makes the country an important player in the region in regard to electricity generation. To this day, Saudi Arabia does not have renewable energy policies that harvest its potential, and almost all its electricity is produced from the combustion of fossil fuels.

FIGURE 1

Share of regional installed capacity of SHP by country

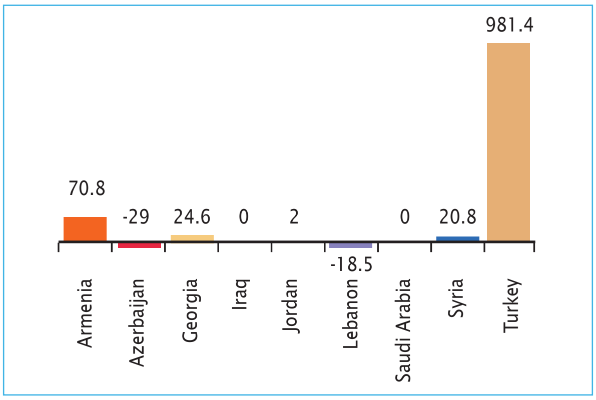


Source: *WSHPDR 2016*[2]

Due to rainfall scarcity and variability coupled with high evaporation rates, the region has been characterized as having limited availability of renewable freshwater. The average annual rainfall ranges from a low of 100 mm (Saudi Arabia) to a high of 1,026 mm (Georgia). The mountainous Caucasus region experiences the highest precipitation (up to 2,500 mm), though there are also dry areas across the region.

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for Western Asia



Sources: *WSHPDR 2013*,[1] *WSHPDR 2016*[2]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. Negative values can be due to closures or rehabilitation of plant sites.
Note: The significant increase in Turkey is due to access to new data and re-evaluation of previous data; it is not indicative of entirely all-new SHP installations.

The climate of the Arabian Peninsula is extremely hot and dry, with temperatures often exceeding 50°C in the summer. The region has two main rivers, the Euphrates and Tigris, and many smaller ones. The Arabian Peninsula sub-region has no reliable surface water supplies, and thus depends entirely on groundwater and desalinated water to meet its water requirements. This is a limiting constraint for hydropower development in the sub-region, especially for Bahrain, Kuwait, Oman, Qatar and Saudi Arabia as well as Israel and Palestine. The overview of countries of Western Asia covered in this report is shown in Table 1.

Fossil fuels are the sole source of electricity generation in the United Arab Emirates, Oman, Qatar, Saudi Arabia and Yemen. As these countries are intensely struggling to overcome water scarcity, there is no hydropower potential, nor plans for future hydropower development in these countries.

Unlike other countries in the region, Jordan has no natural energy resources. Therefore, the country imports energy to meet its demand. Water scarcity is another problem for Jordan, and thus there is little interest in hydropower development.

The Syrian Arab Republic meets its electricity demand mostly from using fossil fuels. Hydropower is the only significant renewable energy source for the country and contributes about 10 per cent to total electricity generation. It is believed that there is more hydropower potential in the country. However, it is necessary to conduct further

TABLE 1

Overview of countries in Western Asia (+ % change from 2013)

Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Armenia	3.02 (-7%)	35.7 (-0.3pp)	100 (0pp)	3,095 (+4%)	7,750 (+19%)	1,194 (-2%)	2,000 (-17%)
Azerbaijan	9.59 (+4%)	45.4 (-2.4pp)	100 (-)	7,348 (+8%)	24,728 (+31%)	1,078 (-40%)	1,300 (-57%)
Georgia	3.73 (-19%)	46.7 (-0.3pp)	100 (-)	3,979 (+17%)	10,592 (+5%)	2,645 (+1%)	8,295 (-11%)
Iraq	34.81 (+8%)	33.6 (+0.2pp)	93 (+7pp)	9,000 (0%)	66,000 (+35%)	2,514 (+0.5%)	4,840 (-4%)
Jordan	7.51 (+24%)	16.3 (-4.7pp)	100 (+0.1pp)	4,350 (+42%)	18,269 (+24%)	12 (0%)	61 (0%)
Lebanon	4.97 (+17%)	12.3 (-0.5pp)	100 (+0.1pp)	2,400 (+4%)	14,826 (+8%)	285 (+4%)	1,007 (+62%)
Saudi Arabia	29.37	16.9	99.9	45,908	198,900	—	—
Syria	22.16	42.4	99.9	7,939	29,992	1,080	3,000
Turkey	77.70 (+3%)	24.9 (-5.5pp)	100 (-)	69,516 (+ 36%)	251,900 (+ 19%)	23,635 (+ 40%)	40,600 (-32%)
Total	**192.86 (+4%)**	—	—	**153,535 (+27%)**	**622,987 (+22%)**	**32,443 (+24%)**	**61,103 (-28%)**

Sources: Various[1,2,5,6,7,8]

Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. Large differences can be due to closures or rehabilitation of plant sites, and/or due to access to more accurate data for previous reporting. Total change percentage values do not include change for Saudi Arabia and Syria.

research to fully explore the country's small hydropower (SHP) potential. As of 2016, there are four SHP plants with a total installed capacity of 20.84 MW.[5]

Armenia meets its electricity demand mainly with nuclear and thermal power plants as well as hydropower plants. Depending on the rainfall, which reveals significant annual fluctuations, between 20 and 40 per cent of the total electricity demand is met by hydropower (39 per cent in 2014). Moreover, the contribution of wind power to the installed capacity of the country is less than 1 per cent.[2]

Azerbaijan utilizes thermal, hydro, solar and wind power to meet its energy demand. Hydropower accounts for 15 per cent of the country's installed capacity. In 2014, the contribution of hydropower to total electricity generation was only about 5.3 per cent.[2]

Georgia meets its electricity demand with hydropower, thermal and deregulated power plants. As of 2014, hydropower accounted for about 66 per cent of the installed capacity. Even though hydropower is the most abundant energy source, it is sometimes unreliable due to seasonal precipitation fluctuations, especially in times where peak demand occurs in the country.

Turkey utilizes diverse energy sources to meet its electricity demand. Even though thermal power plants occupy a major part of energy generation (59 per cent of the total installed capacity), renewable energy sources such as hydropower, wind, geothermal and solar power are also significant contributors to meeting the energy demand of the country. Among these renewable energy sources hydropower accounted for 16.1 per cent of electricity generation in 2014. Even though Turkey utilizes indigenous energy sources (coal in particular), the country is an energy exporter, mostly exporting oil, natural gas and hard coal. Due to its geographical location, Turkey is quite an important country as a transit corridor between the Middle East, where there are abundant oil and natural gas resources available, and Europe.

The electricity supply in Iraq is generated from fossil fuels, hydropower, and energy imports from Iran and Turkey. Hydropower accounts for eight per cent. Most of the population only receives an average of 8 hours of national grid electricity a day. Therefore it is estimated that 98 per cent of the population has alternative power supplies that is not connected to the national grid.

Electricity generation in Lebanon is mostly sustained with imported oil, with about 14 per cent generated from hydropower plants. Although Lebanon has a 100 per cent electrification rate, it still suffers from constant blackouts due to the Lebanese Civil War from 1975 to 1990, which caused widespread damage to transmission and distribution systems. The system has yet to be fully repaired.

Small hydropower definition

Each of the eight countries of the region has a specific classification of SHP in terms of installed capacity, though most of them assume plants with installed capacity of below 10 MW as SHP plants (Table 2).

TABLE 2

Classification of SHP in Western Asia

Country	Small (MW)
Armenia	up to 30
Azerbaijan	up to 10
Georgia	up to 13
Iraq	up to 10
Jordan	up to 12
Lebanon	up to 10
Syria	up to 10
Turkey	up to 10

Source: *WSHPDR 2016*[2]

Regional SHP overview and renewable energy policy

Ten countries in Western Asia utilize SHP. However, this report will only cover eight countries due the limited information about hydropower in Israel and Cyprus. These countries are: Armenia, Azerbaijan, Georgia, Iraq, Jordan, Lebanon, Syria and Turkey. Table 3 shows the SHP potential and installed capacity of the countries in Western Asia.

TABLE 3

SHP in Western Asia (+% change from 2013)

Country	Potential capacity (MW)	Installed capacity (MW)
Armenia	396 (-8%)	282 (+79%)
Azerbaijan	392 (0%)	13 (-69%)
Georgia	187 (-34%)	131 (+97%)
Iraq	26.38 (0%)	6 (0%)
Jordan	58.1 (0%)	12 (+20%)
Lebanon	139.8 (-)	31.2 (0%)
Syria	N/A	20.8
Turkey	6,500 (0%)	1,156.4 (+561%)
Total	**7699.8 (-0.6%)**	**1,652.8 (+238%)**

Sources: *WSHPDR* 2013,[1] *WSHPDR* 2016[2]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. Large differences can be due to closures or rehabilitation of plant sites, and/or due to access to more accurate data for previous reporting. Total change percentage value of installed capacity does not include Syria and excludes the values for Cyprus in the 2013 report.

The leading country in the region in terms of SHP potential is Turkey followed by Armenia, Azerbaijan and Georgia. Lebanon, Jordan and Iraq have relatively limited SHP potential while there is no data on SHP potential available in Syria. The SHP potential of the countries in Western Asia without Turkey is about 1,030 MW and the total installed capacity is about 449 MW.

Turkey has a significant SHP potential—about 6,500 MW. As of 2014, its installed capacity reached approximately 17.8 per cent of its potential. Along with other energy sources, SHP development also gained acceleration in the country due to implementation of such policy instruments as the Electricity Market Law no. 6446 in March 2013 and the Electricity Market Licensing Regulation in November 2013. As of June 2015, there are 772 SHP projects at different licensing stages with a total installed capacity of 3,620.3 MW.[2]

Countries of the region aim to improve their energy security through maximizing the use of local energy resources, in particular renewable ones, including hydropower. Thus, in 2013 the President of Armenia approved an Energy Security Concept, which prioritizes the use of renewable energy resources, while the Government's Development Strategy for 2012-2025 specifically calls for the development of indigenous renewable energy resources. A further 65 SHP plants with an additional estimated potential capacity of 164.672 MW are planned to be built in the country.

Azerbaijan plans to increase the share of renewable energy sources in its total power production, including small hydro plants, from 2 per cent to 20 per cent by 2020. Construction of SHP plants represents one of the priorities of the Government with several new plants planned to be built.

For Georgia with its 26,000 rivers, maximum utilization of water resources remains one of the priorities as well. The Resolution of Government of Georgia no. 214 of 21 August 2013 facilitates sustainable development of the country's renewable energy potential.

In Jordan the first attempts to introduce renewable energy were made in the 1980s, and now renewable energy has gained relevance. Currently, there are two SHP plants operating in the country and planned hydropower projects are expected to generate an additional 7.4 GWh annually.

In Iraq there is no renewable energy policy or framework supporting deployment of sustainable renewable energies, although the Ministry of Electricity has established a Renewable Energy Centre, which at present focuses on developing solar and wind energy.

In Lebanon, there have been developments in the energy efficiency and renewable energy sector. For example, the Government has approved subsidized loans for citizens who take measures towards energy efficiency.

Due to the conflict, Syria has not been able to efficiently implement government initiatives in the energy sector.

Barriers to small hydropower development

The challenges for SHP development in Western Asia highly depend on sub-regional conditions such as climate and water availability. The Arabian Peninsula is struggling to secure water access whereas the Caucasus countries and Turkey are seeking to fully exploit their hydropower potential. For this purpose, political instruments, i.e. master plans, laws, regulations, incentives, have been used (or are planned to be used in the near future) to further develop hydropower potential in Turkey, Armenia, Azerbaijan and Georgia. However, the variation in the hydrological regimes in the region can cause unreliable power plant operation.

The increasing environmental consciousness among people in recent years mostly due to high scarcity of natural resources in the region seems to affect the energy investments in the region, as well as in other parts of the world. Some of the new SHP projects as well as other conventional and renewable energy projects have been halted, especially in Turkey, due to the environmental opposition. This suggests that even though the overall energy demand is increasing in the region and that countries seek to exploit their energy potential, the governments of the region have to find ways to provide sustainable development in the region.

Political instability is considered to be another obstacle for SHP development in the region, especially in countries around the Middle East. The ongoing unrest in Iraq, the war in Syria and terrorist actions lately affecting Turkey may keep potential domestic and foreign investors away from these countries in the future. The political and economic relationships, not only among the countries in Western Asia but also with other important countries around the region such as Russia, Iran, and Ukraine, have been quite delicate lately. This might be critical information for investors who consider investing in the energy sector in Western Asia.

3.5.1 Armenia

Vahan Sargsyan and Lia Aghekyan, Scientific Research Institute of Energy

Key facts

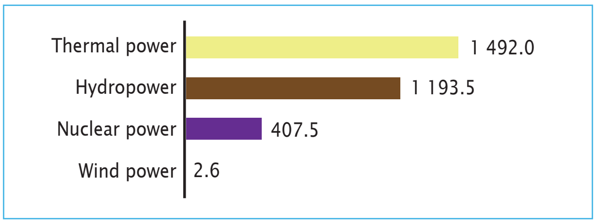
Population	3,017,100[1]
Area	29,743 km[2]
Climate	The climate varies from subtropical to continental. In the southern plain regions the climate is arid and extremely continental. The climate of the northern mountainous regions is mild and wet. Summers are dry and sunny, lasting from June to mid-September. The temperature varies between 22°C and 36°C. Winters last between December and February, with temperatures ranging between –5°C and –10°C.[2]
Topography	Armenia is a mountainous country with the lowest point near the Debed River in the north, at 375 m above sea level. Its highest point is the northern peak of Mount Aragats, at 4,095 m. The average altitude is 1,850 m but the variations in altitude (up to 3,700 m, but more generally 1,500-2,000 m) have important effects on the climatic and landscape zones within the country.[2]
Rain pattern	The average annual precipitation is around 570 mm, ranging from 114 mm in the semi-desert zone to approximately 900 mm in the high mountains. The mountain ranges of the Armenian Territory receive heavy rainfall throughout the year. There are two rainy seasons in Armenia: the first lasts from April to June and the second from October to November.[2]
General dissipation of rivers and other water sources	Even though Armenia is a landlocked country, it features one of the largest alpine and freshwater lakes in the world. Lake Sevan is approximately 940 km[2], or approximately one-sixth of the whole country, and is located 1,900 m above sea level. The largest river in Armenia is the Araks along the border with Iran and Turkey. However, only a portion flows through Armenian territory. There are no major rivers in Armenia apart from the Araks, though the river network of the country is fairly dense, with 215 rivers longer than 10 km and a total length of 13,000 km. The majority of these rivers do not have a permanent flow and are dry in the summer months. The spatial and seasonal distribution of water resources in Armenia is extremely uneven. In particular, water is scarce in the densely populated watershed basin of the Hrazdan River. During dry seasons the flow is less than 65 per cent of the annual average and the maximum and minimum flow ratio can be in the range of 10 to 1.[2,3]

Electricity sector overview

The installed capacity in 2014 was 3,095.6 MW while the available capacity was approximately 2,970 MW. Approximately 48 per cent of electricity generation capacity was from thermal power plants, 39 per cent from hydropower and 13 per cent from nuclear power. Wind power provided about 0.1 per cent (Figure 1).[7]

FIGURE 1

Installed electricity capacity by source in Armenia (MW)

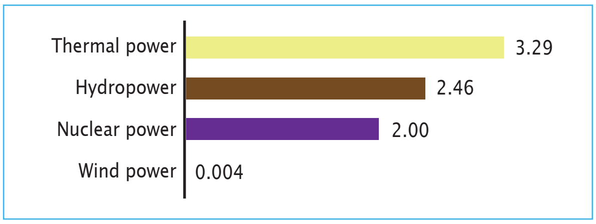


Source: PSRC[7]

In 2014, total electricity generation was 7.75 TWh. Approximately 32 per cent was provided by nuclear power, 42 per cent by thermal power plants and 26 per cent by hydropower. Wind power contribution was negligible at approximately 0.05 per cent (Figure 2).[7] The electrification rate is 100 per cent. Customers have full access to electrical network and grid connection is available for any new user.

FIGURE 2

Electricity generation by source in Armenia (TWh)



Source: PSRC[7]

Natural resources are scarce in Armenia. The thermal power plants work mainly with natural gas. The country possesses no oil reserves, no oil production, and no refineries. There are no oil pipelines and refined products arrive through rail or truck shipments.[13] There is one single nuclear power plant which generates between 30 and 50 per cent of the electricity needs depending on plant uptime.

TABLE 1

Capacity, ownership and wholesale tariffs for main power plants in Armenia

Power plant	Ownership	Installed capacity (MW)	Tariff for energy (Armenian Dram (US$) per kWh)*	Tariff for capacity (Armenian Dram (US$) per kW)*
Armenian nuclear power plant	State	407.5	6.0 (0.013)	4,569.2 (9.60)
Yerevan combined cycle gas turbine	State	242.0	17.9 (0.038)	4,305.4 (9.04)
Hrazdan unit 5 (thermal)	Private	440.0	40.1 (0.084)	—
Hrazdan thermal power plant	Private	810.0	37.1 (0.078)	1,026.3 (2.16)
Sevan-Hrazdan hydropower plants cascade	Private	561.0	1.2 (0.006)	784.4 (1.65)
Vorotan hydropower plants cascade	Private	404.0	8.1 (0.018)	308.1 (0.65)

Source: PSRC[6,7]
Note: * Value-Added-Tax included.

Armenia is under international pressure to decommission this plant, which is considered unsafe. However, the Government is reluctant to close it until alternate generating capacity is online and it is scheduled to operate until 2026. Hydropower plants generate between 20 and 40 per cent of the country's needs depending on rainfall, which exhibits significant annual variation. Power generation from the Sevan-Hrazdan Cascade has had to be reduced because this was causing a drop in water level in Lake Sevan. Thermal plants provide the balance. Armenia has renewable energy resources that can already compete with conventional resources in the generation of electricity. Alongside hydropower, wind power projects (WPPs) with a total capacity of 195 MW and generation of 0.55 GWh per year have been identified.

Operation of the power market is based on the Republic of Armenia Law on Energy. The Ministry of Energy and Natural Resources of Armenia is responsible for the implementation of state policy on energy and natural resources. The market regulation for tariffs setting and operational licenses issuing is under the authority of the Public Services Regulatory Commission (PSRC).[4] The power market is split into three functional areas: generation, transmission and distribution. Table 1 provides details of the main generating plants including tariffs set by the PSRC for power plants. These were effective from 2014 and are intended to cover all expenses. In addition, there are privately-owned small hydropower (SHP) and state-owned wind plants.

High Voltage Electric Networks Closed Joint-Stock Company (CJSC) is responsible for the transmission of power produced by the generating companies to the distribution company, as well as for transporting both electricity imports and exports from/to neighbouring countries. Electric Networks of Armenia CJSC is responsible for the distribution and is the sole buyer of power from all generating companies and the sole seller of power to all the customers at tariffs set by the PSRC.

In addition the National Dispatch Centre is responsible for the maintenance of technically admissible steady-state operations of the system. It also manages the system in power emergencies and the restoration of the system to acceptable operating conditions after a system emergency occurs. The Settlement Centre, by means of the automated data acquisition and metering system, collects and processes data on power flows in the electric network and on technical parameters of the regime, as well as providing the processed data to other market participants.[5] The tariffs for final consumers set by PSRC are dependent on the level of the feeding voltage, the type of connection of the customer to the network (direct and indirect feeder) and on the hour of usage.[6] The consumer tariffs effective from 1 August 2014 are presented in Table 2.

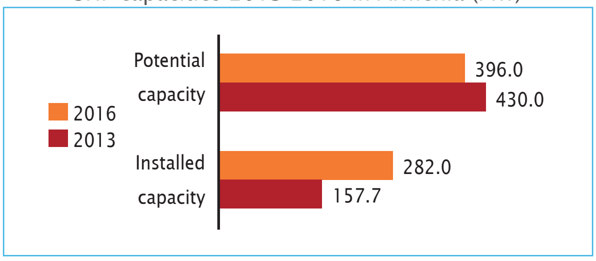
Small hydropower sector overview and potential

According to the Ministry of Energy and Natural Resources of Armenia, SHP is defined as hydropower plants with a total installed capacity up to 10 MW, though some sources define the upper limit at 30 MW.[15,16] For this report, the 10 MW threshold will be used.

As of 1 January 2015, there was a total of 165 SHP plants with a total installed capacity of 282 MW, generating approximately 853 GWh per year. The SHP industry represents approximately 24 per cent of the total hydropower installed capacity and supplies approximately 11 per cent of the annual electrical energy generation in Armenia.

FIGURE 3

SHP capacities 2013-2016 in Armenia (MW)



Sources: *WSHPDR 2013*,[14] R2E2[15]
Note: The comparison is between data *WSHPDR 2013* and *WSHPDR 2016*.

TABLE 2

Electricity tariffs for consumers in Armenia (including VAT)

Consumer type	Day time (Armenian Dram (US$) per kWh)	Night time (Armenian Dram (US$) per kWh)
High voltage consumers (35 kV)	32.85 (0.069)	28.85 (0.061)
6 (10) kV voltage consumers	38.85 (0.086)	28.85 (0.061)
0.38 kV voltage consumers	41.85 (0.088)	32.85 (0.069)
Residential sector	41.85 (0.088)	32.85 (0.069)

Source: PSRC[6]
Note: Night time tariffs are from 22:00 hours to 06:00 hours, starting from 02:00 hours of the last Sunday of March until 03:00 hours of the last Sunday of October; and from 23:00 hours to 07:00 hours, starting from 03:00 hours of last Sunday of October until 02:00 hours of the last Sunday of March.

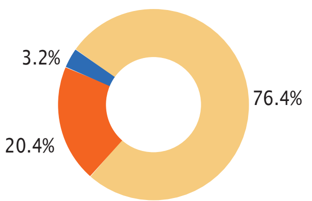
A further 56 SHP plants have received licenses for construction with an additional estimated capacity of 114 MW generating 396 GWh per year, for a total SHP installed capacity of 396 MW. The data indicates that approximately 71 per cent of the total SHP potential in the country has been developed.[15]

Compared to the findings of the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, SHP installed capacity has increased by approximately 79 per cent while potential capacity has decreased by approximately 8 per cent (Figure 4).[14] This is largely due to significant changes in ecological requirements rendering some potential SHP sites unsuitable for development.

The majority of SHP plants, either under construction or operational, are run-of-river type plants. Approximately 76.4 per cent are from natural water flows, 20.4 per cent are part of irrigation systems and 3.2 per cent are part of drinking water systems (Figure 4).[7]

FIGURE 4

SHP sites in Armenia by water source (%)



Source: PSRC[7]

Renewable energy policy

The Government's renewable energy strategy is driven by the overarching goals of improving energy security, ensuring affordable energy supply, and maximizing the use of Armenia's indigenous energy resources. A 2013 Decree of the President of Armenia approved an Energy Security Concept for the country, which prioritizes the use of renewable energy resources while the Government's Development Strategy for 2012-2025 specifically calls for the development of indigenous renewable energy resources. Targets include developing geothermal installed capacity to 28.5 MW and utility-scale solar photovoltaic capacity to between 40 MW and 50 MW.[9]

Legislation on small hydropower

In 2007, the PSRC set renewable energy feed-in tariffs (FITs) for SHP plants, wind, and biomass to stimulate private investment. The feed-in tariff (FIT) regime guarantees purchase of all power generated by renewable energy plants for 15 years. Tariffs are adjusted annually in line with changes in inflation and exchange rates. More recently, the Government took steps to streamline the process of developing renewable energy projects, including relaxing tax obligations for some investments.

As of 1 January 2014 the FIT for SHP plants built on natural water streams was AMD 21.168/kWh (US$0.064), VAT excluded; for SHP plants built on irrigation systems it was AMD 14.110/kWh (US$0.042), VAT excluded; and for SHP plants built on natural drinking sources was AMD 9.408/kWh (US$0.028), VAT excluded. The FIT for wind farms was AMD 38.005/kWh (US$0.114), VAT excluded.[10]

Barriers to small hydropower development

Construction of SHP plants in Armenia is a leading course of action towards development of the renewable energy sector in Armenia.[7] However, the main technical challenge to SHP development in Armenia has been the lack of access to automation and modern control technologies. There is a consensus that many of the SHP plants are technologically sub-standard due to several factors:

- Poor equipment performance and failure;
- Some pipe and materials/civil works problems;
- Substandard or incorrect engineering and/or construction.[8,12]

Additional barriers include:

- Problems with Power Purchase Agreements (PPA);
- Concurrent term, license and water use permits;
- Construction versus operational license;
- Ownership rights;
- Land classification reform;
- Uniform and effective environmental enforcement.[11]

A common theme among all these barriers is a lack of transparency which allows for delays in the approval processes or other problems that should not occur.

3.5.2 Azerbaijan

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Key facts

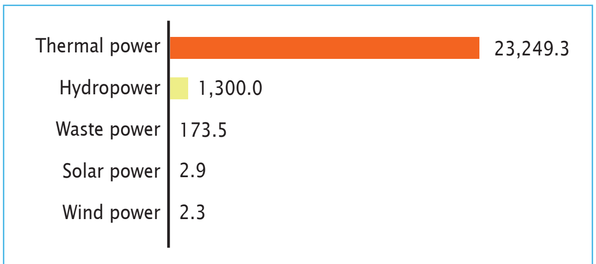
Population	9,593,000
Area	86,900 km^2
Climate	Azerbaijan is situated on the crossing of temperate and subtropical climate zones, with 33 per cent of the territory located in temperate climate zone and 65 per cent in the subtropical. As Azerbaijan is mainly a mountainous country, the temperature changes vertically. Peaks of mountains are covered with snow, while Aran witnesses severe heat. The average annual temperature is 14.5°C in the Kura-Araz lowland and below 0°C on mountain peaks. The lowest temperature was recorded in the higher mountainous area, at –45°C. This is considered as the absolute minimum. The Araz River valley also recorded –32°C. The absolute maximum temperature of 44°C was observed in Julfa town.[2]
Topography	Azerbaijan is situated in the eastern part of the southern Caucasus Mountains, on the west coast of the Caspian Sea. The average height of Azerbaijan is 657 m. The highest point from the sea level is Bazarduzu (4,466 m) and the lowest point is the Caspian coastal lowland (–28 m).[3]
Rain pattern	Precipitation is distributed very unevenly over the territory. The Absheron peninsula and Araz riverside areas of the Nakhchivan Autonomous Republic receives less rainfall (below 200 mm). Rainfall is typically 200-300 mm in the Kura-Araz lowland and 600-800 mm per year in the Lower Caucasus and north-east slopes of the Upper Caucasus. The annual precipitation amounts to 1,200-1,300 mm in the southern slopes of the Upper Caucasus, which are above 2,000-2,500 m in height. The highest value of rainfall was recorded in the southern part of the Lankaran lowland and at the foothills of the Talish Mountains (1,200-1,700 mm).[4]
General dissipation of rivers and other water sources	A very dense river network covers the landscape, with about 8,400 small and large rivers in Azerbaijan, of which 850 rivers stretch for more than five km. The number of rivers longer than 100 km is just 24. The Kura and Araz Rivers, which are the longest rivers of the Caucasus, serve as the main irrigation and hydropower energy sources.[4]

Electricity sector overview

The net capacity of all power stations in Azerbaijan amounted to 7,348 MW, as of the end of 2014; of which, 1,078 MW were from hydropower. In 2014, electricity generation was 24,728 GWh: thermal power (23,249.3 MWh), hydropower (1,300 MWh), electricity generated from municipal waste (173.5 MWh), wind energy (2.3 MWh), solar power (2.9 MWh) (Figure 1).[1,5] The electrification rate in Azerbaijan is 100 per cent.

FIGURE 1

Electricity generation by source in Azerbaijan (MWh)



Source: The States Statistical Committee[1,5]

Azerenerji Open Joint Stock Company, the largest electricity producer in the country, handles the production and delivery of electricity in the Republic of Azerbaijan.

The State Agency for Alternative and Renewable Energy Sources (SAARES) is the central executive authority responsible for pursuing state policy and implementing regulations in the field of alternative and renewable energy; as well as in the effective use of that energy, ensuring efficient organization, coordination and state control over activities on alternative and renewable energy sources.

The Azalternativenerji LLC operating under the auspices of SAARES carries out exploration, processing, production, delivery and distribution activities in the field of alterative and renewable energy sources. It also designs, produces, constructs, exploits and maintains equipment, devices, and facilities for power generation.

A key activity implemented by the Azerenerji OJSC in 2014 was the construction of the second steam-gas gear with a 409 MW capacity at the Northern Power Station, as an acceleration of the execution of the North-2 Project. A new cooling system will be constructed for North-1 and North-2 power stations, sub power stations with 220 kW and 110 kW capacities will be installed and the system for desalinizing sea water is going to be built in the framework of the Project. The station was planned to be commissioned in 2015.[6]

SAARES implemented following large-scale projects over the period of 2010-2014:

(a) The Gobustan Pilot Polygon and Training Centre were put into operation on 13 September 2011. A wind power station (WPS) with capacity of 2.7 MW, a solar power station with capacity of 1.8 MW and a biogas power station (BPS) with capacity of 1.0 MW have been built and commissioned in the polygon.
(b) Surakhani Solar Electric Station (SES) – 2.8 MW (1.2 MW has been assembled via 8,000 solar panels, and an additional 4,000 are to be installed, totalling the capacity OF 2.8. The station is to be connected to the grid by 2015).[13]
(c) Samukh SES – 2.8 MW (1 MW was assembled and will be connected).
    (i) Pirallahi SES – 2.8 MW (1.1 MW was assembled and will be connected).
    (ii) Sumgayit SES – 2.8 MW (1.7 MW was assembled).
    (iii) An existing small hydropower (SHP) station in Sheki has been expanded and a new hydro unit with capacity of 580 KW has been built and is ready for operation.

TABLE 1

Electricity tariffs in Azerbaijan

Name of service	Tariffs per 1 kW/hour (VAT included) in US$
Wholesale tariffs	
Production at “Azerenerji” OJSC	0.039
Production at private small-scale hydropower stations	0.024
Production at wind power stations	0.043
Retail tariffs	
For all consumers	0.057
Transmission tariffs	
Transmission of electricity	0.019
Chemical and aluminium industries, steel mills operating on mining ore which are directly connected to 35 and 110 kV power transmission lines, have a daily stable power load demand and consume more than 5 GWh of electricity for the production purposes on a monthly basis	
By day (from 8.00 am 10.00 pm)	0.040
At night (from 10.00 pm to 8.00 am)	0.019

Source: Tariff Council of the Azerbaijan Republic[7]

Projects under planning and construction phases:

- Garadagh SES with capacity of 2.8 MW – under construction;
- In the Samukh Agro Power Facility, SES with capacity of 20 MW, Biomass units with capacity of 8 MW and Geothermal station with capacity of 3 MW – under the design stage;
- Hybrid power stations using variations of wind. Solar, and biogas energies, with capacity of up to 10 MW in Nakhchivan AR, Neftchala, Gadabay, Oghuz, Balakan, Gazakh, Gakh, Yevlakh, Khachmaz, Khizi and Lerik regions, are under the design stage.

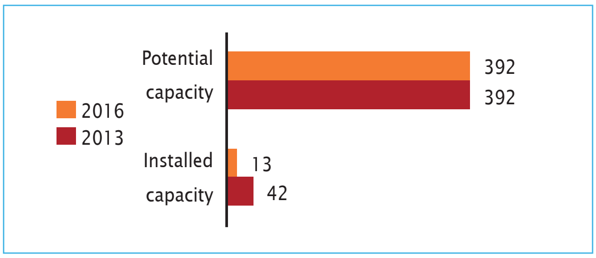
According to Protocol No. 3 of the Tariff (price) Council of the Republic of Azerbaijan dated 6 January 2007, prices for electricity as listed in Table 1.

Small hydropower sector overview and potential

The definition of SHP in Azerbaijan is up to 10 MW. Installed capacity of SHP is 13 MW while the potential capacity is estimated to be 392 MW indicating that approximately 3 per cent has been developed. Between the 2013 and 2016 installed capacity has been reduced by 69 per cent but the potential capacity hasn’t changed (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Azerbaijan (MW)



Sources: IRENA,[10] *WSHPDR 2013*[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

SHP plants are facilities with capacity ranging from 50 to 10,000 kW, installed on a permanent stream, ensuring prompt return of the used water to its regular course. There are several SHP projects underway, as construction of small-scale hydropower plants is among the priority projects.[10]

The Mughan and Sheki private SHP plants produced 11.6 GWh in 2014.[9] The State commissioned the Sheki hydropower plant with the capacity of 0.58 MW which has been installed and connected to the general grid. The Goychay-1 hydropower station with a capacity of 3.3 MW and the Balakan-1 hydropower station with a capacity of 1.5 MW are ready for use and electricity is produced at those facilities on a pilot basis. Construction of several stations, the Isamayilli-2 hydropower station (1.6 MW), the Astara-1 hydropower station (0.3 MW), and the Oghuz-1, Oghuz-2 and Oghuz-3 hydropower stations (total capacity of 3.6 MW) are about to be completed. With the transmission of electricity produced at those power stations to the local grids, the provision of electricity to some settlements in adjacent areas will be further improved.[6]

Renewable energy policy

The share of renewable energy sources in total power production, including small hydro plants, is currently 2 per cent, and there are plans to increase this to 20 per cent by 2020. According to the State Agency for renewable and alternative energy sources (ABEMDA), by 2020 Azerbaijan will have a solar PV capacity of 2,065 MW, solar heating power stations with a total capacity of 4,500 MW, biomass-fired stations totalling 515 MW, wind power capacity of 512.5 MW and small hydro capacity of 60 MW. The regions considered most favourable for wind power are on the coast of the Caspian Sea, from northern Shabran to Sumgait, the Gobustan district, the Absheron peninsula, and the Nakhchivan Autonomous republic. The Kur-Araz lowland area, the Absheron peninsula, Gobustan district and Nakhchivan are considered to have the best potential for solar energy production.[12]

A number of important legal and regulatory changes have been adopted in the Republic of Azerbaijan, in addition to those aimed at boosting the development of SAARES. Relevant Presidential decrees, orders and decisions of the Cabinet of Ministers have been signed and implementation tools have been defined for those legal and regulatory acts. Currently, work is underway to draft other legal and regulatory changes. Below are the main legal and regulatory acts pertaining to ARES:

- Law of the Republic of Azerbaijan on the Use of Energy Resources (30 May 1996 94-IQ);
- Law of the Republic of Azerbaijan on Electro-energetics (3 April 1998 459-IQ);
- Law of the Republic of Azerbaijan on Energetics (24 November 1998 541-IQ);
- Law of the Republic of Azerbaijan on Power and Thermal Stations (28 December 1999 784-IQ);
- Decree 512 of the President of the Republic of Azerbaijan dated 17 November 1996 on the Application of the Law of the Republic of Azerbaijan on "Use of Energy Resources";
- Decree 810 of the President of the Republic of Azerbaijan dated 1 February 2013 on the "Establishment of the State Agency for Alternative and Renewable Energy Sources of the Republic of Azerbaijan";
- Decree 462 of the President of the Republic of Azerbaijan dated 21 October 2004 on the approval of the State Program on the Use of Alterative and Renewable Energy Sources in the Republic of Azerbaijan;
- Decree 635 of the President of the Republic of Azerbaijan dated 14 February 2005 on the approval of the State Program on the Development of Fuel-energy Facilities in the Republic of Azerbaijan (for 2005-2015 years);
- Decree 594 of the President of the Republic of Azerbaijan dated 16 November 2009 on Additional Measures for the Application of Alterative and Renewable Energy Sources in the Republic of Azerbaijan;
- Decree 32 of the President of the Republic of Azerbaijan dated 4 May 2011 on the approval of the State Program on the Socio-economic Development of Baku City and its Settlements for 2011-2013;
- Decree 1958 of the President of the Republic of Azerbaijan dated 29 December 2011 on the preparation of the State Strategy for the Use of Alterative and Renewable Energy Sources in the Republic of Azerbaijan for 2012-2020;
- Decree of the President of the Republic of Azerbaijan dated 17 January 2014 on the approval of the State Program on the Socio-economic Development of Baku City and its Settlements for 2014-2016;
- Order 18 of the Cabinet of Ministers of the Republic of Azerbaijan dated 2 February 2005 on the approval of the Rules on the use of electricity power;
- Order 95 of the Cabinet of Ministers of the Republic of Azerbaijan dated 20 May 2010 on the approval of the Rules on granting of special permission for activities related to alterative and renewable energy sources;
- Order 217 of the Cabinet of Ministers of the Republic of Azerbaijan dated 16 August 2013 on making amendments to the Rules on granting of special permission for activities related to alterative and renewable energy sources approved with the Order' 95 of the Cabinet of Ministers of the Republic of Azerbaijan dated 20 May 2010.

SAARES participates in the formation of a single state policy on alternative and renewable energy and the efficient use of energy from those sources, ensures implementation of that policy, development of and creation of relevant infrastructure in this field, application of alternative and renewable energy in the economy and social life; as well as implements relevant measures related to production, consumption and efficiency of energy generated on the basis of ARES, keeps state records and state cadastre, drafts and drives preparation of related legal and regulatory acts.[8]

Legislation on small hydropower

In addition to the legislation mentioned in the previous section, in particular the 1996 Energy Resources Law, the 1998 Electric Energy Law and the 1999 Law on Energy, there is legislation with a focus on hydropower.

Order' 216 of the Cabinet of Ministers of the Republic of Azerbaijan dated 6 December 2000 on the approval of Rules on the use of water facilities for the hydro-energetic needs.

Barriers to small hydropower development

There are specific challenges pertinent to SHP development, besides those of general character. The following can be cited among them:

- Absence of regular updates of river data;
- Problems connecting to the general electric grid;
- Construction of SHP plants in areas with difficult mountainous conditions;
- Low level of tariffs.

3.5.3 Georgia

Manana Dadiani, Energy Efficiency Centre Georgia; David Sharikadze, Ministry of Energy of Georgia

Key facts

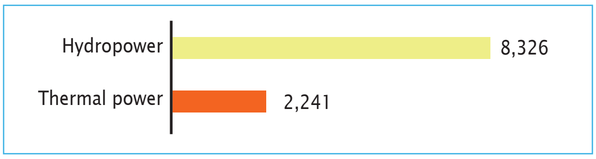
Population	3,729,000[1]
Area	69,700 km²
Climate	Western Georgia has a humid subtropical, maritime climate while eastern Georgia has a climate ranging from moderately humid to a dry subtropical type. The average annual temperatures are between 14°C and 15°C, with extremes ranging between 45°C and -15°C. The Black Sea influences the climate of west 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 10°C to 2°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]
Topography	Georgia has a mountainous landscape, 54 per cent of its surface is located at or above an altitude of 1,000 m. The country lies mostly in the Caucasus Mountains,[4] and its northern boundary is partly defined by the Greater Caucasus range. The highest point is Mount Shkhara, which reaches 5,201 m, while the lowest point is on the coast of the Black Sea, between Poti and Kulevi, reaching from 1.5 to 2.3 m below sea level. In addition to the Great Caucasus, other mountain ranges include the Lesser Caucasus range, which runs parallel to the Turkish and Armenian borders, and the Likhi Range, which runs north to south dividing the country into its eastern and western regions.[3]
Rain pattern	Western Georgia has heavy rainfall throughout the year, totalling between 1,000 and 2,500 mm, and reaching a maximum between September and February. The Southern Kolkhida region in the south-east of the country receives most of the rain. In eastern Georgia precipitation decreases with distance from the sea, reaching between 400 and 700 mm in the plains and foothills but increasing to double this amount in the mountains. The south-eastern regions are the driest in the country, with the driest period in winter between December and February and the wettest at the end of spring in May.[3]
General dissipation of rivers and other water sources	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 main five rivers 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 km².[3]

Electricity sector overview

In 2014, total installed capacity was approximately 3,979 MW. This figure includes 2,644.7 MW of hydropower, 1,180.0 MW of thermal power and 154.3 MW of deregulated power plants; these are termed deregulated on the basis that plants with an installed capacity of below 13 MW have the right to operate without a license and sell generated power directly to consumers.[7] The available capacity is 3,087.4 MW, largely due to the working capacity of the thermal power and deregulated plants which are just 670 MW and 24 MW, respectively. In 2015, total electricity generation reached 10,592.5 GWh; 79 per cent of which was provided by 69 hydropower plants (Figure 1).[5] Eleven of these plants are regulated providing approximately 60 per cent of all generation from hydropower and 50 per cent of total generation. Twelve hydropower plants operate on a seasonal basis contributing approximately 25 per cent of total generation, while 46 deregulated hydropower plants contributed five per cent. The remaining 20 per cent of total generation came from two thermal power plants and one gas turbine (Figure 2). The demand in 2015 reached 11,291.7 GWh with the difference of 699.3 GWh made up with imports, over 70 per cent of which came from Russia.[5]

FIGURE 1

Electricity generation in Georgia by source (GWh)



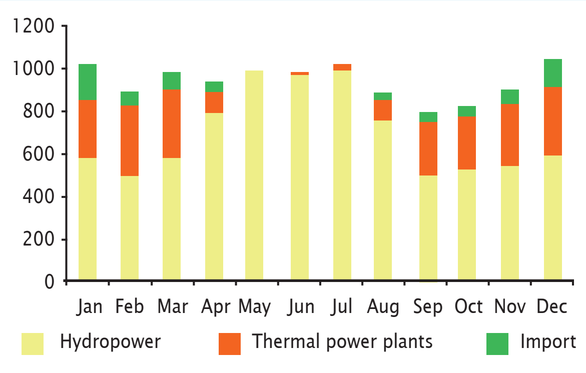
Source: ESCO[5]

Due to fluctuations in precipitation, Georgia is both an importer and exporter of electricity. From May to July

2015, hydropower alone not only satisfies domestic demand but also supplies the exports. However, outside May to July, available capacity has not been able to meet peak demand and nearly half of the total production is generated by thermal power plants and imports (Figure 2). Currently Georgia is a net importer of natural gas and petroleum products, which are, together with hydropower and biomass for residential heating, the country's main energy sources.

FIGURE 2

Annual generation in Georgia by source Jan-Dec 2015 (GWh)



Source: ESCO[5]

Georgia has succeeded in significantly liberalizing the electricity market and implementing 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 of Georgia 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 approval of strategic projects.[7]

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 regulating tariffs (including for generation, transmission, dispatch, and distribution), monitoring of the quality of services provided by license holders and dispute resolution. The GNEWSRC is also authorized to impose sanctions for regulatory breaches.[8]

The Electricity System Commercial Operator (ESCO) is the commercial operator responsible for: balancing the market and ensuring grid stability, conducting export/import operations to meet systemic needs and for emergency purposes, and creating and managing a unified database on the wholesale purchase and sale of energy, 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, as a balancing market, thus 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 information required to carry out supply and plan consumption.[9]

The Georgian State Electrosystem (GSE) is the transmission system owner and operator and the sole dispatch licensee. Its main function is technical control and supervision over the entire power system to ensure an uninterrupted and reliable power 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.[10]

The generation tariff for hydropower in Georgia is the lowest in the region at approximately US$0.02/kWh. This compares favourably with the tariff for the Azeri thermal power plants (US$0.03/kWh), despite their subsidized gas prices. The private wholesale tariff in Georgia has been fluctuating between GEL 0.0117/kWh (US$0.007) and GEL 0.0749/kWh (US$0.044) throughout 2014 with higher prices during winter.[6] The average wholesale price for electricity in 2014 was GEL 0.053/kWh (US$0.031).[6]

The main objective of the Government's energy policy is to raise the national energy security. Other objectives include:

- Diversification of supply sources, optimal utilization of local resources and reserves;
- Utilization of Georgia's renewable energy resources;
- Gradual approximation of Georgian legislative and regulatory framework with that of the European Union;
- Energy market development and improvement of energy trading mechanism;
- Strengthen the role of Georgia as a transit route in the region;
- Georgia – regional platform for generation and trade of clean energy;
- Develop and implement an integrated approach to energy efficiency in Georgia;
- Taking into consideration environmental components in the implementation of the energy projects;
- Improving service quality and protection of consumer interests.

The main objective of the long-term energy policy is the attraction of foreign investments for the construction of the new power plants. According to the potential of high-capacity power generation and the increasing demand, other key objectives of the energy policy include:

- Rehabilitation of the infrastructure connecting to the energy systems in neighbouring countries;

TABLE 1

SHP sites at licensing and construction stage

Project	Company	Estimated investment (US$)	Estimated installed capacity (MW)	Estimated annual generation (GWh)
Lukhuni HPP 2	Rusmetali Ltd (Georgia)	23,000,000	12.0	73.6
Nabeglavi HPP	AE-SGI Energy I (Georgia)	2,800,000	1.9	13.0
Kintrisha HPP	Hydro Development Company (Georgia)	8,000,000	5.0	30.0
Skhalta HPP	Clean Energy (Norway)	10,000,000	6.0	27.1
Arakali HPP	Optimum Energy Üretim A.I. (Turkey)	18,150,000	8.8	48.1
Okropilauri HPP	Alter Energy (Georgia)	2,600,000	1.8	9.4
Goginauri HPP			1.8	9.3
Debeda HPP	Hydrolea Ltd (Georgia)	3,125,000	2.5	13.0
Kasleti HPP 1		9,060,000	8.1	46.4
Kasleti HPP 2		10,500,000	8.1	45.8
Avani HPP	LTD “Energo Invest”	644,000	4.6	18.6
Jonouli HPP 1	LTD “Khvamli”	154,000	1.1	5.1
Jonouli HPP 2		924,000	6.6	30.0
Jonouli HPP 3		1,820,000	13.0	65.0
Total		**90,777,000**	**81.3**	**434.4**

Source: Ministry of Energy of Georgia[14]

- Construction of new transmission lines and substations;
- (c) Export of the surplus power generated in new and existing power plants.[16]

Small hydropower sector overview and potential

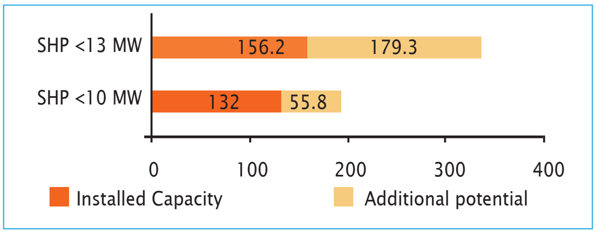
Small hydropower (SHP) is defined as plants with an installed capacity of below 13 MW.[7] The total installed capacity of SHP plants of below 13 MW is 156.2 MW, 131.6 MW of which is from plants of below 10 MW. SHP potential for plants of below 13 MW is estimated at 335.5 MW, of which 187.4 MW is for plants up to 10 MW. This data suggests that approximately 32 per cent of SHP potential for plants up to 13 MW and approximately 40 per cent of plants up to 10 MW have been developed (Figure 3).[7]

Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has almost doubled while estimated potential has decreased by approximately 35 per cent. This is partly due to the development of new SHP plants as well as access to more accurate data (Figure 4).[7,20]

Currently there are 46 SHP plants (below 13 MW) in operation, all of which are privately owned.16 of those 46 are in need of refurbishment. Although the installed capacity totals 156.2 MW the working capacity is just 24.0 MW. In total they generate approximately 492.1 GWh per year equivalent to approximately 6.3 per cent of total hydropower generation.[9] There are 26,000 rivers in Georgia, with an estimated total capacity potential of 40 TWh.[11] SHP technical potential (below 13 MW) is estimated at 19.5 TWh.[12] An overview of the potential SHP sites up for tendering is available on the website of the Ministry of Energy.[13] Tables 1 and 2 provide a list of ongoing investment projects and sites with feasibility studies completed.[14]

FIGURE 3

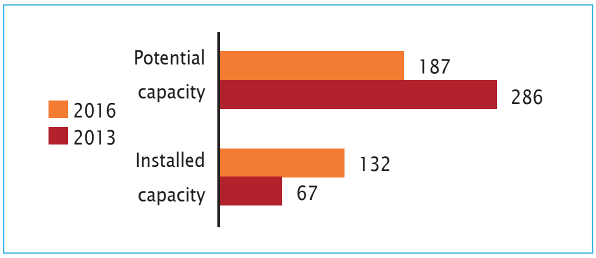
SHP capacities for plants up to 10 MW and up to 13 MW (MW)



Source: Ministry of Energy[7]

FIGURE 4

SHP capacities 2013-2016 in Georgia (MW)



Sources: Ministry of Energy,[7] *WSHPDR 2013*[20]
Note: For plants up to 10 MW.The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016.*

Renewable energy policy

The main objective of the Government's overall energy policy is to raise the national energy security and this explicitly includes the utilization of local renewable energy sources, the optimal utilization of resources and reserves and consideration of environmental components in the implementation of energy projects.[18]

In 2010 some Georgian municipalities (Tbilisi City, Rustavi City, Batumi City, Kutaisi City, Poti City, Gori municipality, Zugdidi municipality and Telavi municipality) joined the European Union initiative and signed a *Covenant of Mayors* committing to reduce CO_2 emissions by 20 per cent by 2020. Some of the Georgian signatories (Tbilisi City, Rustavi City, Batumi City and Gori municipality) elaborated on the Sustainable Energy Action Plans (SEAP), which envisages the implementation of energy efficiency and renewable energy measures in various sectors. In this sense the SEAPs reflect the only real political documents on energy efficiency and renewable energy policy at a local municipal level.

TABLE 2

SHP sites at feasibility study stage

Project	Company	Estimated investment (US$)	Estimated installed capacity (MW)	Estimated annual generation (GWh)
Ubisa HPP	Georgian Hydro Power LLC (Georgia)	560,000	4.00	19.00
Surebi HPP	Supsa Energy LTD	966,000	6.90	40.80
Vani HPP		1,064,000	7.60	44.50
Bukistsikhe HPP		1,036,000	7.40	40.70
Supsa Mtsire HPP		154, 000	1.10	6.30
Baramidze HPP		1,036,000	7.40	44.00
Artana HPP	Artanalopota Ltd	350, 000	2.50	13.50
Lopota HPP 1		1,120,000	8.00	46.00
Kvirila HPP		924 ,000	6.60	40.00
Trialeti HPP	Trialeti 2013 Ltd (Georgia)	560, 000	4.00	21.50
Khokhnistskali HPP 1	Mardihouse Ltd (Georgia)	798,000	5.70	33.00
Khokhnistskali HPP 2				
Khokhnistskali HPP 3				
Zeda Bghugha HPP	Georgian International Energy Corporation Ltd	1,372,000	9.80	41.00
Buja HPP 1	EG Ltd (Georgia)	228 200	1.63	8.70
Buja HPP 2		140 000	1.00	5.22
Buja HPP 3		324 800	2.32	12.25
Skurdidi HPP	Pshavi Hydro Ltd	198 800	1.42	9.30
Paldo HPP	Iori Energy JCS	952 000	6.80	48.90
Didkhevi HPP	Deka LLC	182 000	1.30	7.00
Rachkha HPP	LTD GN ELECTRIC	1,435,000	10.25	31.50
Mazhieti HPP	LTD Enteli	1,715,000	12.25	56.40
Ghere HPP		1,162,000	8.30	44.70
Cirmindi HPP		1,876,000	13.40	65.80
Mleta HPP	LTD Imedi In	763, 000	5.45	36.20
Qvesheti HPP		1,407,000	10.05	67.40
Udzilaurta HPP	LTD Udzilaurta HPP	1, 080,800	7.72	38.28
Saguramo HPP	LTD Saguramo Energy, LTD Georgian Water and Power	588, 000	4.20	36.35
Laskadura HPP	LTD Laskada Energy	924 ,000	6.60	10.20
Sashuala HPP 1	LTD Energy Development Georgia	714, 000	5.10	35.50
Sashuala HPP 2		695,800	4.97	34.20
Total		**24,326,400**	**173.76**	**938.20**

Source: Ministry of Energy of Georgia[14]

In 2013 the Government set forth a legislative initiative (Resolution of the Government of Georgia No 214, 21 August 2013) in order to facilitate sustainable development of the national renewable energy potential.[19] This initiative regulates procedures and rules of expression of interest (EOI) for construction, ownership and operation of power plants in Georgia.[15] The maximum utilization of water resources is one of the priorities of the State.

In 2013 the Ministry of Energy of Georgia also established the division of Energy Efficiency and Alternative Sources. Currently this department is actively working on the development of the national energy efficiency and renewable energy policy with United States Agency for International Development (USAID).[17]

Legislation on small hydropower

The regulation of the hydropower sector offers many advantages to potential investors. Newly built hydropower plants remain the exclusive property of investors through a Build-Operate-Own (BOO) scheme. Newly constructed SHP plants with an installed capacity of below 13 MW do not require an operating license. They do, however, require construction and environmental permits. The electricity generated by SHP plants of below 13 MW may be used by the developer for their own needs. It is nearly always financially advantageous to consume as much of the power as possible on site and only export the surplus into the network. If it is feasible to connect to the local grid, the produced electricity may be exported via the local distribution network through an agreement with ESCO or with the local distribution companies that deliver electricity directly to the client.

From 1 September to 1 May, within the scope of the direct agreement made in compliance with standard conditions, the highest tariff is based on the thermal power plant electricity sold to ESCO. In this same period the adjustable fixed tariff based on hydropower is the lowest tariff established by GNERC. Small capacity power plants may purchase electricity to ensure they fulfil the agreement on electricity generated. However, the volumes should not exceed the framework of the forecasted electricity volumes proposed.

If the SHP plant produces power 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 into their system.

Barriers to small hydropower development

Georgia is the only country in the Caucasus region that has not adopted energy efficiency and renewable energy laws. This is more of a sign of underdevelopment rather than of a specific economic policy. Indeed, this field is related to modern technologies, research and development, advanced institutions, commercial and banking systems and commercial companies. Its implementation requires high levels of energy awareness and the subtle mechanisms of economic incentives that are characteristic of a highly developed society. This is one of the essential elements for European energy cooperation and refusing it means rejecting development and international technological and financial assistance. Key barriers to SHP development include:

- SHP plants are not competitive in terms of cost of generation compared to large and medium capacity plants;
- SHP plants have profound seasonal variation in output and depend highly on river runoff conditions. In the winter, rivers in Georgia suffer from insufficient water flow, negatively impacting electricity supply.

3.5.4 Iraq

Abdul-Ilah Younis Taha, Baghdad University

Key facts

Population	34,812,326[1]
Area	435,000 km[2]
Climate	Iraq is mostly desert, with mild to cool winters and dry, hot, cloudless summers. The northern mountainous regions along the Iranian and Turkish borders experience cold winters with occasionally heavy snows that melt in early spring, sometimes causing extensive flooding in central and southern Iraq.
Topography	The terrain comprises mostly broad plains with reedy marshes along the Iranian border in south that see large flooded areas and mountains along its borders with Iran and Turkey.
Rain pattern	Roughly 90 per cent of the annual rainfall occurs between November and April. The western and southern desert region receives brief heavy rainstorms in the winter of about 100 mm in total. In the upland region, there is essentially no precipitation in summer and some showers in winter (winter rainfall averages about 380 mm). The alluvial plain of the Tigris and Euphrates delta in the south-east receives most of its precipitation, accompanied by thunderstorms in winter and early spring. The average annual rainfall for this area is only about 100 to 170 mm. In the mountains of the north and north-east precipitation occurs mainly in winter and spring, with minimal rainfall in summer. Above 1,500 m, heavy snowfalls occur in winter, and there is thunderstorm activity in summer. Annual precipitation for the whole region ranges from 400 to 1,000 mm.[2]
General dissipation of rivers and other water sources	Iraq is home to two historically important principal rivers, the Tigris and Euphrates. The courses of these rivers are roughly parallel, with both flowing across central Iraq towards the south-east. The Euphrates is the longest river in the country. Iraq's largest lake, Buhayrat ath Tharthar, or Lake Tharthar, lies in the centre of the country.

Electricity sector overview

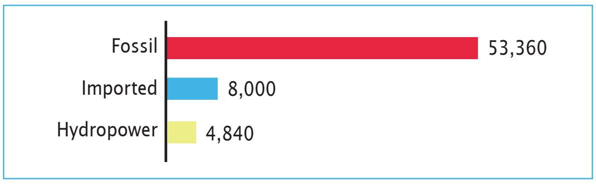
The electrification rate in Iraq has dropped from about 98 per cent in the late 1990s to 93 per cent at present. About 15 per cent of the power generated provides continuous supply to essential services. The remaining population gets typically eight hours of national grid electricity each day. It is estimated that 98 per cent of the population has alternative power supplies, either obtained through neighbourhood or private generators. An exception is the autonomous region of Iraqi Kurdistan, where the population has access to electricity 24 hours a day.[3]

The country's electricity supply totalled 66,000 GWh in 2012, of which 58,000 GWh were generated from domestic power plants and 8,000 GWh were imported from Iran and Turkey. About 92 per cent (approximately 53,360 GWh) of power was generated from fossil fuels, while the remaining 8 per cent (approximately 4,840 GWh) was from hydropower (Figure 1).[4] Installed capacity was approximately 9,000 MW.[3]

Iraq has the third highest oil reserves in the world. Due to the nation's political instability, it still faces energy shortages. According to the national energy master plan, about 24,400 MW of new capacity will be added between 2012 and 2017, including 13,000 MW of gas-fired capacity, 7,000 MW of thermal power capacity and 400 MW of renewable energy by 2015. A further 4,000 MW will be added by the conversion of simple-cycle power plants to combined-cycle technology.[3]

FIGURE 1

Electricity generation in Iraq (GWh)



Source: EIA[4]

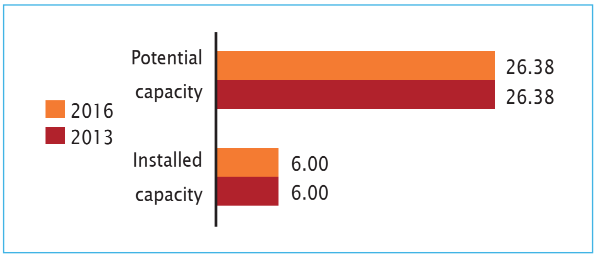
While hydropower development is part of the long term strategy, the country is currently more interested in developing power plants in the short term; hence gas and oil-fired plants are the preferred choice. There is also more focus on developing large dams for irrigation and flood protection. Wind and solar parks are also desired.

Small hydropower sector overview and potential

There is no uniform definition of small hydropower (SHP) plants in Iraq, so for the purpose of this paper small hydro projects have been classified as those from 10 MW and below. Installed capacity of SHP in Iraq is 6 MW while the hydropower potential is estimated to be 26.38 MW indicating that approximately 23 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed and potential capacity has not changed (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Iraq (MW)



Sources: *WSHPDR 2013*,[8] Ameen[6]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Apart from there being no consensus regarding the definition of SHP in Iraq, there is no official definition from the Government either. Generally, however, a capacity of up to 80 MW is considered small. The installed capacity of SHP projects (according to the country's definition of up to 80 MW) is about 10 per cent of the total hydropower capacity. Currently, there are six SHP stations operating in Iraq (Table 1). Only one of the listed projects has a capacity below 10 MW.

TABLE 1

Installed hydropower capacity in Iraq (MW)

Project name	Installed capacity (MW)	Ownership
Dokan Dam	400	Iraqi Government
Darbandikhan Dam	240	Iraqi Government
Mosul Main Dam	750	Iraqi Government
Mosul Dam pump storage plant	200	Iraqi Government
Mosul Regulating Dam	60	Iraqi Government
Haditha Dam	660	Iraqi Government
Samaraa Barrage	80	Iraqi Government
Hemrin Dam	50	Iraqi Government
Adhaim Dam	40	Iraqi Government
Al-Hindiyah Barrage	15	Iraqi Government
Shatt Al-Kuffa Regulator	6	Iraqi Government
Total installed capacity	**2,501**	

Source: Ameen (2007)[6]

It is estimated that the full hydropower potential may be as high as 80,000 GWh annually. In 2006, the Ministry of Water Resources issued a guidance note, Phase I, as part of its Strategy for Water and Land Resources in Iraq.[5] The note is based on an earlier study by the Ministry of Heavy Industry. Examination of the flows used indicates that calculations do not take new developments in upstream riparian countries into consideration, resulting in an overestimation of the hydropower potential. It lists 78 potential hydropower stations and lists for each station the total potential installed capacity, the rated discharge, the annual energy production, the static head and the unit cost in IQD/kW. It does not explicitly indicate whether the units are SHP, but this can be summarized from other listed data.

Phase II of the Strategy for Water and Land Resources in Iraq updated flow and installed capacity data for 87 potential hydropower sites, depending on new information on upstream developments, and reduced the potential hydropower sites to 49 with installed capacities between 5 MW and 261 MW as shown in Table 2.

TABLE 2

Potential hydropower sites under study in Iraq

Installed capacity MW	Number of sites
5-10	6
11-20	7
21-30	5
31-50	12
51-100	12
101-150	6
261	1

Source: Ameen[6]

Only 30 sites have installed capacity of 5 MW to 50 MW. The Iraqi National Water Development Strategy stipulates that hydropower should be developed as a by-product of any new dam, and that in the mix of non-fossil fuel energy sources hydropower targets are 5 per cent in Iraq and 19 per cent in Kurdistan. As such, it is not foreseen that many hydropower dams will be built in the future.

A strategic assessment of the 49 potential hydropower sites based on a number of technical, economic, social and environmental criteria concluded that only 20 sites would offer an acceptable return on investment. Six of these sites are in the Kurdistan region and 14 in the rest of Iraq. In addition, there are four dams in the Kurdistan region in the planning stage, which brings the total to 24 dams. The combined installed capacity of the hydropower dams in Iraq is 1,029 MW and the annual energy generation is 6,667 GWh. The combined installed capacities of the hydropower dams in Kurdistan region is 867 MW and the annual energy generation is 5,528 GWh. The time frame for construction of these dams is 2016 to 2023. The projected hydropower energy generation from all dams is expected to be about 15,500 GWh per year starting from the year 2020.

In addition to new construction, there are 30 existing barrages and regulators where hydropower with installed capacity up to 80 MW may be added. Applying the SHP definition of up to 10 MW, it is estimated that there are at least 12 potential SHP sites available with an estimated capacity of 26.38 MW.[6]

TABLE 3

SHP sites under study in Iraq

Name of regulator	Units	Design discharge (m^3/sec)	Potential capacity (MW)
Tarthar Water Divider Regulator	4	171	5.662
Al-Sader Al-Mushtarak Regulator	3	60	1.300
Al-Abbasiya Regulator	2	168	4.683
Al-Btera Regulator	2	118	3.016
Al-Hilla Head Regulator	8	189	2.634
Al-Dagara Regulator	2	31	0.508
Al-Kahla Regulator	2	67	2.394
Al-Kassara Regulator	1	24	0.601
Al-Garraf Head Regulator	4	158	3.650
Qal'at Salih Regulator	2	25	0.416
Al-Khalis Regulator	1	49	0.760
Al-Diwaniya Regulator	3	49	0.755
Total	**34**	—	**26.379**

Source: Ameen[6]

The Ministry of Water Resources is currently undertaking a study entitled Strategy for Water and Land Resources of Iraq. The aim is to develop an integrated strategy for developing and managing water resources throughout Iraq to ensure sustainable management and development of the national water and land resources. The utilization of the hydropower potential is an integral part of the study.

Renewable energy policy

The Ministry of Electricity has established a Renewable Energy Centre. Its main focus at present is to develop solar and wind energy. The Ministry of Heavy Industry commissioned a study on hydropower resources use in Iraq in 1988.[7] The study was undertaken by Technopromexport, an entity that belonged to the Union of Soviet Socialist Republics, and addressed, among other issues, hydropower development and its contribution to the coverage of the load curve in the national power grid. However, there is no renewable energy policy or framework supporting deployment of sustainable renewable energies.

Barriers to small hydropower development

- Times of war and sanctions have left the energy sector, rural agriculture and water infrastructure in a terrible state;
- Constantly evolving plans, frequently cancelled tenders, and risks associated with payments and security continue to hold the power sector back.[3]

3.5.5 Jordan

Mohammad Hassan Al-Zoubi, Yarmouk University

Key facts

Population	7,510,000[1]
Area	89,342 km²
Climate	Jordan is characterized by long, hot, dry summers and short, cool winters. Its climate is influenced by its location between the subtropical aridity of the Arabian Desert areas and the subtropical humidity of the eastern Mediterranean area. January is the coldest month, with temperatures from 5°C to 10°C, and August is the hottest month, at an average temperature of 20°C to 35°C. Daytime temperatures can be very high, especially in summer; on some days it can reach 40°C or higher. Summer winds are strong and hot, causing sandstorms at times.
Topography	Jordan's main topographical feature is a dry plateau running from north to south. This rises steeply from the eastern shores of the Jordan River and the Dead Sea, reaching a height of between 610 and 915 m. In the west runs the Great Rift Valley, a deep depression, which includes the Jordan Valley, the Wadi Araba and the Dead Sea. In the area of Lake Tiberias the valley is about 213 m below sea level and the Dead Sea marks the world's lowest point, at 395 m below sea level. In the east, the land slopes downwards from the plateau to the semi-arid steppe country of the Syrian Desert. The Eastern Desert occupies about 80 per cent of the country. Jabal Ramm in the south is Jordan's highest point, which reaches 1,753 m.[3]
Rain pattern	Jordan receives most of its rainfall during the autumn and winter months, October to May. The annual rainfall is less than 200 mm on average, with most of it evaporating back to the atmosphere. Over 70 per cent of the country receives less than 100 mm of rainfall a year, while only 2 per cent of the land area, located in the north-western highlands, receive over 300 mm a year. The most northern highlands sometimes receive as much as 600 mm.[5] Precipitation is often concentrated in violent storms, causing erosion and local flooding, especially in winter.[4]
General dissipation of rivers and other water sources	The high evaporation rate often results in a relatively small annual stream flow of about 878 million m^3, excluding the Jordan River flow. The valley streams of north the Jordan River and the Yarmouk River in Jordan plateaus into the Dead Sea. The Dead Sea, which is located in the central area of the valley, consists of salt marches that do not support vegetation. To the north, there are valleys that contain perennial streams running west. Around the Al-Karak area, they begin to flow west, east and north.[19]

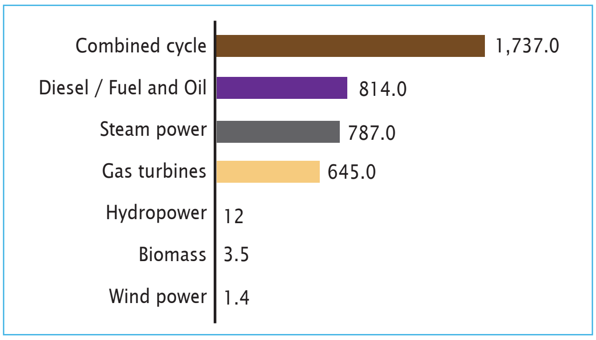
Electricity sector overview

In 2014, installed electricity capacity in Jordan was 4,350 MW, with an available capacity of 4,000 MW; the peak load was 3,050 MW. The annual generated electricity was 18,269 GWh. Available capacity consisted of combined cycle (1,737 MW), diesel/fuel and oil (814 MW), steam (787 MW), gas turbines (645 MW), hydropower (12 MW), biogas (3.5 MW) and wind power (1.4 MW) (Figure 1). The electrification rate is 100 per cent.[7]

The production of electrical energy on average grew 10 per cent during the last 20 years.

FIGURE 1

Installed capacity in Jordan



Source: NEPCO[10]

The National Electricity Power Company (NEPCO) operates the bulk network in Jordan, which is composed principally of 400 kV and 132 kV circuits. The transmission system is structured on north-south axis of Jordan. It is essentially a radial system with no looping except for a small ring around the main load center of Amman. The distribution systems are served from this system at 132 kV. The direct service bulk customers are also served from this system. There are about 3,200 circuit-km of transmission lines currently operated at 132 kV, which represents about 77 per cent of total networks. In addition, there are 904 circuit-km of transmission lines operated at 400 kV. Moreover, the Jordanian power system is interconnected with the Egyptian power system through a 400 kV submarine cable crossing the Gulf of Aqaba in the southern part of Jordan. The northern part of Jordan is interconnected with Syrian power system.[6,7]

Despite being adjacent to several oil-rich countries, Jordan struggles to secure its energy resources, especially under the burden of high oil prices. Industrial development requires more fuel consumption and the continuous operation of power plants. Therefore, the search for alternative energy sources has become an important issue in Jordan.[6] Although the electricity generation units can burn both diesel and gas fuels, more than 80 per cent of the currently generated electricity comes from burning imported gas.[7]

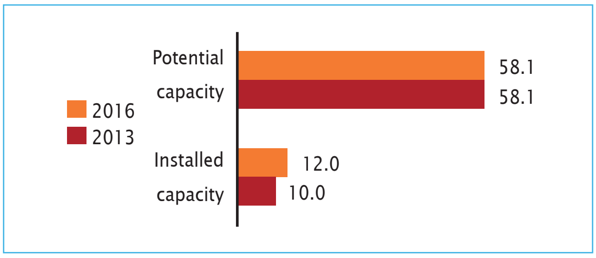
The electricity market was partially privatized using a single buyer scheme at the end of 1990s, but this policy did not affect the electricity tariff. The structure takes into account social aspects as well as the economic capacities of consumers. In 2014, the electricity prices for the end consumer ranged from JD 0.033/kWh (US$0.047/KWh) for small residential consumers with less than 150 kWh per month demand to JD 0.292/kWh (US$0.41/KWh) for the banking sector. In 2012, the generation and distribution costs were JD 0.146/kWh (US$0.21/KWh), whereas the average selling price was JD 0.0636/kWh (US$0.09/KWh). The difference in price had to be covered by the state-owned National Electric Power Company, thereby creating a substantial deficit of JD 2.3 billion (US$3.25 billion) by the end of 2012. In order to reduce the losses, a National Strategic Plan was developed. It foresees the adjustment of electricity tariffs and other measures to enhance the efficiency of the electricity system. By the end of 2017, NEPCO is expected to be able to cover its costs. The plan prescribes the electricity price development for different consumer categories until the year 2017. Nevertheless, electricity is subsidized for many categories, e.g. for consumers with low electricity consumption.[9]

In addition to the power plants operated by the public utilities, there are also a number of industrial enterprises that generate electricity in their own plants. Some of these also feed excess electricity into the Jordanian interconnected grid. Since the amount of electricity generated in Jordan has for some years been insufficient to cover the country's needs, additional power used to be imported from Egypt. However, due to the circumstances in the region, import has been reduced or stalled. Jordan is considered to have huge reserves of oil shale, which can be utilized commercially by direct incineration to produce electricity. The Jordanian Government has decided to market oil shale, aiming to attract international companies to utilize it. The strategic plan is to rely on oil shale for 14 per cent of the energy mix by 2020.[11] It is expected to have a primary source of electrical energy from oil shale, although the plans for nuclear power are also under discussion. However, the contribution of hydropower is relatively small as shown in Figure 2.[12]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Jordan is up to 10 MW. Installed capacity of SHP is 12 MW while the potential capacity is estimated to be 58.1 MW indicating that approximately 21 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 20 per cent while estimated potential hasn't increased (Figure 2).

FIGURE 2
SHP capacities 2013-2016 in Jordan (MW)



Sources: *WSHPDR 2013*,[18] Jabera, J.O.[15]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

In 2010, two SHP schemes were operational in Jordan, one is located at the Aqaba thermal power plant, where its hydropower turbine utilizes the available head of returning cooling seawater, with a capacity of 5 MW; whereas the other is at King Talal dam spanning the river Zarqa, with a rated electricity-generating capacity of about 5 MW.[15] Though the two SHP plants produce less than 0.5 per cent of the total national electricity generation, there is a great possibility to generate electricity by developing the elevation difference between the Red Sea and the Dead Sea. A preliminary pre-feasibility study showed that the potential capacity of a hydropower station built in this region could be 800 MW.[11,15] Although several international investors have shown an interest in this field, the main barrier for executing this project is the lack of funding. SHP potential is estimated at 58.15 MW.[17]

SHP plants are not generally affected by the constraints associated with large hydro projects: they are more environmentally and socially acceptable. Large scale hydropower development is becoming a challenge due to environmental and socio-economic concerns, and more recently its vulnerability to climate change. In addition, investment in large hydroelectricity generation requires substantial upfront investment capital.[15]

Recently, the Ministry of Water and Irrigation announced several water projects which could potentially generate 7.4 GWh annually. These projects will be built in all water treatment plants distributed around the country to reduce the consumption of electrical energy and widening the usage of renewable energy in Jordan. All of these projects will be connected to the national electric grid. Water pumping consumes more than 14 per cent of the installed capacity, so those projects are important. Such projects will be successful after gaining enough experience from the Alsamra water treatment plant which used the water flow extracted from the plant to generate more than 10 GWh of electricity annually.[16]

Renewable energy policy

The attempts to introduce renewable energy as a support or replacement to the conventional resources began in the 1980s. Several goals were achieved in the last two decades, which makes renewable energy one of the important energy sources in Jordan.[6]

Hot summer months, July and August in particular, are associated with a high rate of electricity consumption in Jordan. With a mean temperature of around 35 °C, most of the summer load consists of electric fans, water pumps and air conditioning.[13,14] The best months for wind energy production in Jordan are the summer months, the wind energy production increases the importance of existing and planned wind farms. This facilitates promoting wind energy projects in Jordan.

Barriers to small hydropower development

Although the potential capacity of SHP is more than 50 MW according to the studies done by the Ministry of Water and Irrigation, the existing plants are still limited.[17] There are a number of barriers limiting the development of hydropower. Among these barriers are:

- Limited SHP development due to limited availability of surface water resources. Jordan is one of the countries with the least water availability;
- Lack of local technical SHP capacities, contributing to the high cost of these (imported) services and/or goods;
- Absence of incentives and investments from private sector to operate and own SHP;
- Limited access to funding sources for SHP and low confidence by investors on this source of power.

3.5.6 Lebanon

Karim Osseiran

Key facts

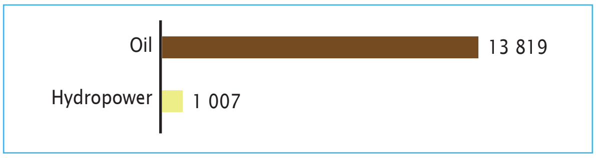
Population	4,970,000[1]
Area	10,452 km[2]
Climate	The climate is Mediterranean, with mild to cool, wet winters and hot, dry summers. Lebanon's mountains experience heavy winter snows.[2]
Topography	Lebanon consists of four physiographic regions: the coastal plain, the Lebanon mountain range, the Beqaa Valley and the Eastern Lebanon mountains. Of the country's surface, 1.6 per cent is water. The highest point in Lebanon is Qurnat as Swada, at 3,088 m above sea level, in North Lebanon, which gradually slopes to the south before rising again to a height of 2,695 m in Mount Sannine.[2]
Rain pattern	Winter is the rainy season, with major precipitation falling after December. Rainfall is generous but is concentrated during only a few days of the rainy season, falling in heavy cloudbursts. The amount of rainfall varies greatly from one year to the next. Occasionally, there are frosts during winter, and about once every 15 years a light powdering of snow falls as far south as Beirut.[2]
General dissipation of rivers and other water sources	The mountains of Lebanon are drained by seasonal torrents and rivers. An important water source in southern Lebanon and even in the country as a whole is the Litani River. The river originates from the Beqaa Valley, west of Baalbek, and flows into the Mediterranean Sea north of Tyre. Exceeding 140 km in length, the Litani is the longest river in Lebanon and represents a major source for water supply, irrigation and hydroelectricity.[2]

Electricity sector overview

Electricity generation in 2012 was 14,826 GWh with another 323 GWh imported. Electricity generation is dominated by imported oil (13,819 GWh), the balance is generated by hydropower (1,007 GWh) (Figure 1).[1] The total installed capacity is approximately 2,400 MW, the installed hydropower capacity is 285.2 MW but available capacity is only 150 MW. The largest hydropower schemes are on the Litani river: Paul Arcache (109.5 MW), Charles Helou (48 MW), Ibrahim Abdelal (36 MW).[8]

FIGURE 1

Electricity generation by source in Lebanon (GWh)



Source: IEA[7]

Despite its 100 per cent electrification rate, Lebanon suffers from frequent power blackouts. The 1975-1990 Lebanese Civil War caused widespread damage to transmission and distribution systems and the electric grid has not fully recovered. Électricité du Liban (EDL) suffered enormous financial losses during the war. Aside from instability within its own border, regional unrest in the neighbouring countries of Syria and Palestine has caused an enormous influx of refugees into Lebanon.[3]

Self-generation in Lebanon is significant, it is estimated that the installed capacities of existing off-grid generation may account for more than the utility generation. Self-generation plays an essential role in electricity supply and demand in Lebanon. Self-generation and un-served demand are not recorded systematically. Lebanon is estimated to have about 33 per cent of total electricity demand met through self-generation.[9] The household study in 2006 puts the number at 38 per cent. As service has deteriorated since that time and since demand is increasing, the share of private generation has increased to more than 50 per cent of total electricity demand. The industrial sector has a total estimated power generation installed capacity of about 200 MW. Hotels, schools, universities and hospitals have an estimated 100 MW. Residential buildings have their own generators with a total estimated capacity of more than 600 MW.[9]

The legal framework for privatization, liberalization and unbundling of the sector (Law 462) exists but is not applied. In parallel, the law implemented by decree 16878/1964 and 4517/1972 which gives EDL exclusive authority in the generation, transmission, and distribution areas is still being applied. The failure to reform the electricity sector has caused an annual deficit of US$1.5 billion and losses to the national economy are estimated to be at least US$2.5 billion per year. This crisis is caused by the lack of investment, the high fuel bill which fluctuates with the rising cost of fuel, the operating status of power plants which are old, inefficient and uneconomical, the high technical and commercial losses in transmission and distribution, the wrong tariff structure and low average tariff and the deteriorating financial, administrative, technical and human resources of EDL; all in the presence of convoluted legal and organizational frameworks.[5]

In 2012 the Government, represented by the Ministry of Energy and Water (MoEW), entered into a contract agreement for renting 270 MW of reciprocating engines mounted on floating barges. The agreement states that deployment of this capacity should be done on a fast track basis. The first power barge, moored at the existing Zouk thermal station, started operation in the winter of 2013 and is supplying a total capacity of 188 MW to the 150 kV network. The second barge, moored at the Jieh thermal station, started operation in the summer of 2013 and is supplying a total capacity of 82 MW to the 150 kV network. According to the contract, this is an Energy Conversion Agreement under which the risk of and security of fuel supply is on behalf of the Government. According to the policy, these rental units are aimed at supplying the required additional power in the summer as well as to act as a standby capacity needed for two to three years to rehabilitate the existing units at Zouk and Jieh.

Currently, there are two reciprocating engine power plants under construction at the sites of Zouk and Jieh for the installation of 194 MW at the site of Zouk and 78.2 MW at the site of Jieh. The engines are designed to run on a tri-fuel basis of Heavy Fuel Oil (HFO), Diesel Oil (DO) and Natural Gas (NG) when available. To boost efficiency these units will run in combined cycle mode, HRSGs will be installed at the exhaust of the engines collecting waste heat to generate steam and run small steam turbines. According to the contract this is a fast track construction concept where the full capacity is expected to be online 18 months after the official starting date.

MoEW had also entered into an engineering, procurement and construction (EPC) contract for the installation of a 565 MW CCGT power plant at the land extension of the existing Deir Amar CCGT. The plant is composed of three GE frame 9E units, three HRSGs and one steam turbine. The plant is designed to run on a dual fuel basis and shall fire HFO at a de-rated capacity of 539 MW until natural gas is available to the plant. Actual construction work is expected to start soon. Similar to previous contracts, this is a fast track construction concept where the full capacity is expected to be online within 26 months after the official starting date.

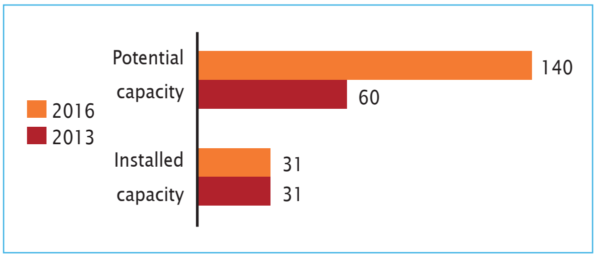
As part of an operation and maintenance contract EDL had managed to implement upgrade packages sequentially for the V94.2 GT's at Zahrani and Deir Amar. The upgrade plan was completed by the end of summer 2013. The upgrades managed to add a capacity of at least 63 MW in total in addition to enhancements in efficiency and lifetime extensions.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Lebanon is up to 10 MW. Installed capacity of SHP is 31.2 MW, while the potential is estimated to be 139.8 MW, indicating that less than 22 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity remained the same (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Lebanon (MW)



Sources: *WSHPDR 2013*,[4] SOGREAH,[11] Électricité Du Liban[12]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Lebanon has seven small, mini, and micro hydro plants in operation with a total capacity of 31.2 MW. An additional 108.6 MW of potential capacity was derived from planned SHP plants, with an expected total annual generation of 533 GWh.[11]

A policy paper was approved in 2010, which included hydropower development, maintenance and rehabilitation/upgrade of existing hydro plants, implementation of additional 120 MW hydropower capacities on an IPP/PPP basis and investigating the feasibility of micro-hydropower.

A hydro master plan was drafted in June 2012 by the Ministry of Energy and Water covering the feasibility of the installation of new hydro plants. According to the study, 32 new sites were identified. These sites were categorized as follows:[10]

- 263 MW (1,271 GWh/yr) run-of-river with a total investment cost of US$667 million;
- 368 MW (1,363 GWh/yr) peaking scheme with a total investment cost of US$772 million.

25 of these sites were considered economical as the minimum selling tariff was calculated to be below US$0.12/kWh and are given as follows:

- 233 MW (1,126 GWh/yr) run-of-river with a total investment cost of US$560 million;
- 315 MW (1,217 GWh/yr) peaking scheme with a total investment cost of US$665 million.

Additionally, the assessment of the micro hydropower potential from non-river sources within different water systems to include irrigation systems, drinking water systems, electrical power plant outfall pipes and waste water treatment plants was conducted on 13 selected sites, which have been evaluated technically and economically:[10]

- Irrigational Channels and Conveyers
  The primary function of this source is irrigation, which needs to be maintained at the required minimum pressure and flow. The production of electricity is a secondary priority and must not undermine the primary function. The hydropower plant has to be designed in a way to make optimum use of available head and flow at different irrigation regimes.
- Waste water treatment plants inlet and outfall pipes
  There are two possibilities for using the hydropower potential in such systems. One is to install a turbine at the inlet of the wastewater treatment plant, using untreated wastewater. The other is to use the potential of the treated wastewater before it is returned into the receiving water.
- Thermal power plants' outfall pipes
  Large thermal power plants require significant amounts of cooling water. Cooling water is normally taken from the sea, pumped to a heat exchanger, and returned via the outfall pipes to the sea. The available hydropower potential depends on the specific situation/topography at the respective thermal power plant. For example, a turbine can be installed at the outlet of the discharge cooling water system at a thermal power plant.
- Drinking water distribution networks
  The primary function of these systems is to supply drinking water to the consumers at a specified supply pressure. Where there is a need for pressure reduction, the excess pressure can be used to drive a hydroelectric system.

There are different possibilities to produce electricity within drinking water systems. One concept is to install a turbine at the entrance of the reservoir or the storage tank at the water distributing station.

Another option is to install it within the supply networks. In that case, normally a certain residual pressure—as required for the distribution network—has to be maintained.

The total electrical power potential for the 13 sites amounts to an estimated 5 MW. More than 50 per cent of this identified hydropower potential was found in currently established thermal power plants. Besides having a high energy potential, they require a relatively low investment and thus have short payback periods. They can be implemented in the course of potential rehabilitations of these power plants.

Drinking water systems have a theoretically high hydraulic potential in Lebanon but the use of the existing pipelines for hydropower generation would result in very high friction losses and low energy production.

Wastewater treatment plants do not have significant potential for power generation, but may be subject to substantial energy efficiency measures. Some of them are still under construction and review, which provides the opportunity for more investigation for the hydro potential and to make necessary adjustments on the design of the treatment plants to integrate the proposed hydropower plants.

Studies for the assessment of the micro hydropower potential from river sources are currently under preparation.[6]

Renewable energy policy

The major contributor to the renewable energy mix in the country is hydropower. Lebanon enjoys relatively better access to water than neighbouring countries. Lebanon has a significant wind potential, especially in the north. This can be deduced from measurements of tree deformation that correspond approximately to wind speeds of 7-8 m/sec. A national wind atlas has been produced providing only indicative estimates as well as aggregating the total potential wind in the country. There is an abundant solar resource with an average annual insolation of 1,800-2,000 kWh/m^2. Solar water heating is established in the country but the technology for power generation is generally expensive. Therefore, solar power is foreseen only at the micro level and for specific applications like street lighting, water heating and other municipal use.

For the past few years, Lebanon witnessed some developments in the energy efficiency and renewable energy sectors. The Ministry of Energy and Water (MoEW) provided subsidized loans for the citizens to install solar water heating systems and remove electric heaters from the grid. Another initiative was the replacement of three million incandescent lamps with compact fluorescent, an investment worth US$7 Million. According to MoEW this created a significant drop in demand amounting to 160 MW and a CO_2 reduction of 245,000 tons.

In 2012 the Government announced the National Energy Efficiency Action Plan (NEEAP), which was considered a strategic document to pave the way for the overall national objective of 12 per cent of renewable energy by 2020. The NEEAP includes 14 independent but correlated activities in the energy efficiency and renewable energy sectors listed below:

- Towards banning the import of incandescent lamps to Lebanon;
- Adoption of the energy conservation law and institutionalization of the Lebanese Centre for Energy Conservation as the national energy agency for Lebanon;
- Promotion of decentralized power generation by solar PV and wind applications in the residential and commercial sectors;
- Solar water heaters for buildings and institutions;

- Design and implementation of a national strategy for efficient and economic public street lighting in Lebanon;
- Electricity generation from wind power;
- Electricity generation from solar energy;
- Hydropower for electricity generation;
- Geothermal, waste to energy, and other technologies;
- Building code for Lebanon;
- Financing mechanisms and incentives;
- Awareness and capacity building;
- Paving the way for energy audit business;
- Promotion of energy efficient equipment.

Barriers to small hydropower development

- Water is scarce. Precipitation rates are significantly lower than 50 years ago and water consumption for irrigation and potable use is drastically increasing. Thereby hydro development will rely increasingly on the construction of new dams during the following decades.
- There are too many stakeholders involved in the sector. The Ministry of Energy, the Ministry of Agriculture, the Electric Utility, various water establishments, old private concessions and the Council for Development and Reconstruction. The rights regarding water and the right to produce power are not well defined under a coherent and comprehensive legal framework. As a result none of the stakeholders are able on their own to develop the hydropower sector.
- The Electric Regulation Authority, as well as the Independent Power Producers (IPP) law and the Public Private Partnership (PPP) law are still not in place. Therefore the participation of the private sector is still not possible.
- There is no Grid Code in Lebanon and the financial, technical and administrative regulations for the insertion of new small hydro into the network are still non-existing.

3.5.7 Saudi Arabia

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Key facts

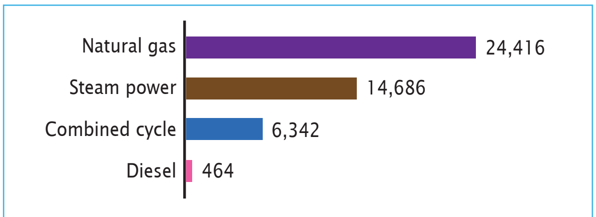
Population	30,886,545[1]
Area	2,149,690 km^2
Climate	Saudi Arabia has a harsh, dry desert climate with great temperature extremes.[2,3] The temperature distribution across the country is controlled mainly by altitude and, to a lesser extent, proximity to the sea. With the exception of the mountains, typical daytime temperatures from May to September are between 38°C and 43°C (several degrees higher on some days) in comparison to 30°C-32°C at 2,100 m 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 at low lying Dhahran, Makkah and Jizan to 25°C at the more elevated Riyadh, 22°C at Tabuk (800 m) in the north-west and 20°C at Khamis Mushait (2,100 m) in the south-west.[4,5,6]
Topography	The Kingdom of Saudi Arabia (KSA) is a country representing about 80 per cent of the territory of the Arabian Peninsula. It has 2,410 km of sea coast, of which 1,760 km stretches along the Red Sea and 650 km 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 kingdom is mostly sandy desert, with the lowest point in the Arabian Gulf at 0 m and the highest point at Jabal Sawda' at 3,133 m.[7]
Rain pattern	Spring and winter have the highest rainfall.[8] However, rainfall is unreliable and annual average totals are typically around 100 mm or, especially inland, less—for example, Tabuk, inland in the north-west as 35 mm. The wettest area is the far south-west region where Saudi Arabia's highest mountains sit. Most of the rainfall occurs in the spring and summer convection, raising annual totals to 199 mm at Khamis Mushait (about 2,100 m above mean sea level) and 141 mm at Jizan on the adjacent coastline. In the northern half of the country, rain falls mainly during November to April from weak weather systems moving eastwards from the Mediterranean or North Africa.[5,6,9]
General dissipation of rivers and other water sources	Saudi Arabia is a desert country with no permanent rivers or lakes and very little rainfall.

Electricity sector overview

In 2013 electricity generation was 198,900 (GWh) with an installed capacity of 45,908 (MW); 100 per cent is generated by using fossil fuels (Figure 1).[14]

FIGURE 1

Installed capacity by source in Saudi Arabia (MW)



Source: SEC[14]

The Kingdom of Saudi Arabia is divided into five geographical regions: Eastern, Central, Western, Southern, and Northern. In each of the Eastern, Central, and Western regions, there is an interconnected grid that feeds the major load centres of the region. In these three geographical regions, the 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 resulting in a grid for the Southern region's major load centres. In the Northern region, there are a number of isolated systems.

Driven by population growth, a rapidly expanding industrial sector led by the development of petrochemical cities, high demand for air conditioning during the summer months, and low electricity tariffs, the electricity use in Saudi Arabia has risen by about 7-8 per cent annually over the last decade, with summer peak demand increasing by 93 per cent between 2004 and 2013 (from 28 to 54 GW). Between 2013 and 2020, the Saudi electricity demand is expected to increase by over 6 per cent annually. This future electricity demand growth will require power generation capacity to increase to 120 GW by 2032. The demand in the residential sector particularly remains strong, with the sector consuming 50 per cent of the Kingdom's total electricity production, the remaining being split among industry, commercial sector and government agencies (18 per cent, 11 per cent and 12 per cent respectively). Climate is a major factor as 70 per cent of the electricity sold is attributed to air conditioning, adding to the seasonality of demand; with summer peak demand nearly twice the winter average.[11]

In addition, integrating the electricity grids of the Gulf Cooperation Council (GCC) countries could provide the region with an additional potential for cross-border and intercontinental energy exports during off-peak season. Saudi Arabia and the neighbouring countries could benefit from the connection of their northern Gulf grid connection (linking Saudi Arabia, Kuwait and Qatar) with the Turkish and European grids to take advantage of the very large spare capacity the Saudi system has in the winter months. Saudi Arabia plans to set up a grid connection with Egypt to take advantage of differences in each national system's daily demand peaks; the connection could operate at a level as high as 3 GW. An even more ambitious plan under consideration is to share power on a seasonal basis. Such a system could supply as much as 10 GW to help meet European winter peak demand, while sending back power in the summer to reduce the peak demand in the Gulf.[11]

The Eastern Operating Area (EOA) is the largest producer of electricity in the Kingdom. EOA is connected to the Central Operating Area (COA) by a 230 kV double circuit and two double circuit 380 kV lines.

Small hydropower sector overview and potential

Due to scarcity of water, there isn't hydropower potential for development nor have hydropower plants been installed. The scarcity of water in Saudi Arabia has triggered the installation of massive seawater desalination facilities making the kingdom the world's largest producer of desalinated water. In 2002, Saudi Arabia's water desalination output surpassed one billion cubic metres, nearly 70 per cent of the Kingdom's freshwater needs. Some of the desalination facilities are dual-purpose plants producing more than 20 per cent of the Kingdom's total electricity needs. Due to the county's dry and harsh climate, rainfall is sparse with an annual average of about 100 mm per year compared to 1,123 mm annual average global precipitation. In spite of the low rainfall, dams have been constructed to make use of the little rainfall to recharge subterranean water and control flooding. Today, there are more than 200 dams in the kingdom with a cumulative reservoir capacity of 774 million cubic metres. The King Fahd Dam is the largest in the country and the second largest in the Middle East with a storage capacity of 325 million m^3, a surface area of 18 km^2 and 103 m head. The King Fahd Dam has a theoretical potential energy of about 328,055 GJ or 91.2 MWh. However, the effectiveness of dams in Saudi Arabia in containing rainfall water is greatly undermined by the excessive evaporation and sedimentation.[11,12]

Renewable energy policy

KSA has the world's largest proven oil reserves, the world's fourth largest proven gas reserves, has abundant wind and solar renewable energy resources, and is the world's 20th largest producer and consumer of electricity. Saudi Arabia makes negligible use of its renewable energy resources and almost all its electricity is produced from the combustion of fossil fuels.

Having vast renewable energy resources mainly in the form of solar energy, Saudi Arabia has realized the benefits in curbing domestic oil consumption in order to generate billions of dollars by exporting the savings at higher prices. Unlike other countries exhibiting high population density, the Kingdom's vast desert can host large solar installations and huge deposits of clear sand that can be used to manufacture silicon photovoltaic (PV) cells. In addition to the diversification of the Saudi domestic mix, renewable energy will contribute to the reduction of their emissions growth (NOx, SOx and CO_2), effluents and water usage, and will provide alternative means of serving remote areas in a more economic and clean manner.

The Kingdom has set a goal of producing almost half of its power from renewable fuels by 2020 in order to meet 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 plan, costing US$109 billion, to install 41 GW of solar energy (25 GW CSP and 16 GW PV), 9 GW of wind, 3 MW of waste-to-energy and 1 MW of geothermal by 2032, corresponding to 30 per cent of electricity generation.

In addition to the advantage of diverting significant quantities of oil and gas from power generation to other more efficient uses, the Kingdom can enjoy additional returns from the alternative energy economic sector, in particular in terms of employment.

At the end of 2013, Saudi Arabia had the second highest solar PV installed capacity among the Arab states, with 19 MW, right after the UAE (33 MW).[11]

Barriers to small hydropower development

Saudi Arabia is the largest country in the world without a natural river running to the sea. Water bodies in the kingdom constitute 0 per cent of its area with total renewable water resources estimated at 2.4 km^3 and nearly depleted underground water resources. A study aimed at modelling the annual and monthly evaporation for the King Fahd Dam using an auto-regressive first order model and fragments method based on data collected over 22 years found that the average evaporation is 10.1 mm/day with highest evaporation rate in July of 14.31 mm/day and lowest in December of 5.89 mm/day compared to 0.27 mm/day of rainfall. This is not a surprise knowing that nearly a quarter of the solar power incident on the earth's surface is consumed in the evaporation of water. All this leads to the predictable conclusion that the environmental and climatic conditions necessary for a successful utilization of hydropower are missing in Saudi Arabia.[13]

3.5.8 Syrian Arab Republic

Sameer Sadoon Algburi, Al-Kitab University College

Key facts

Population	22,160,000[1]
Area	183,630 km^2
Climate	The climate in Syria is semi-continental except in the coastal areas. It experiences hot, dry and sunny summers (June to August) and mild, rainy winters (December to February) along the coast; and cold weather with snow or sleet periodically in Damascus.[3] West of the Jabal An Nusayreyah, Syria has a Mediterranean-influenced climate, characterized by long, hot and mostly dry summers and mild, wet winters. At Aleppo, in the north-west, the average August temperature is about 30°C and the average January temperature is 4°C. At Tudmur, in the central region at the edge of the Syrian Desert, the corresponding temperatures are slightly higher—31°C in summer and 7°C in the winter months. The differences between day and night temperatures can be quite significant, especially in the dryer inland areas, where the nights can be surprisingly cool.[4]
Topography	Syria is located on the western part of Asia, on the eastern coast of the Mediterranean Sea. More than 90 per cent of its land is located approximately 400 m above sea level. It consists of three morphological units: ▸ The coastal area, which is a narrow stretch from north to south along the Mediterranean coast; ▸ The mountainous area, which consists of two coastal mountains that stretch from north to south, with the highest peak being Haramoun Mountain, at 2,800 m; ▸ The flat area, comprising Al Omok flat, Al Rouj flat and Al Ghab flat; a group of internal flats that form most of Syria (Al Jazeera, Damascus, Homs and Hama, Aleppo, and Horan.[5]
Rain pattern	In Syria it mainly rains during winter, from 1,600 mm in the coastal and mountainous areas to 300 mm in the internal and Al Jazeera area, to 100 mm in Al Badia (the desert) and eastern area.
General dissipation of rivers and other water sources	There are 16 main rivers and tributaries in the country, mainly located in the northern part of country, with the Euphrates being the largest.

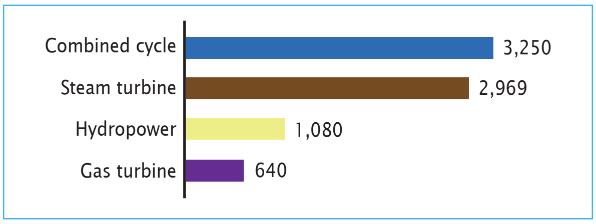
Electricity sector overview

The 2013 annual report of the Public Establishment for Electricity Generation and Transmission (PEEGT) shows that power generation fell by 30 per cent in 2013 to 29,922 GWh from 42,092 GWh in 2012. Combined cycle plants now account for almost 40 per cent of the country's effective generating capacity of 7,939 MW. Steam turbine plants, most of which run on natural gas, with fuel oil as back-up, account for just under 3,000 MW of available capacity. Most of the remainder is made up of stand-alone gas turbine plants (640 MW) and three hydroelectric plants on the Euphrates, which have a combined operating capacity of 1,080 MW. Approximately 94 per cent of electricity is generated using natural gas or oil (Figure 1).[6]

Two main operators in the Syrian electricity sector are the Public Establishment of Electricity for Generation and Transmission (PEEGT) and the Public Establishment for the Distribution and Exploitation of Electrical Energy (PEDEEE), under the supervision of Ministry of Electricity. Peaks of the demand are in winter when electricity is widely used for heating and to a lesser degree in summer, when it is needed for air conditioning. Load shedding is still common and standby generators are being widely used.

FIGURE 1

Installed capacity by source in Syria (MW)



Source: The Economist Intelligence Unit[6]

Syria has interconnections at the 400 kV level with Turkey, Jordan and Lebanon and is a part of the regional grid which also includes Egypt and Libya. Interconnections at the 400 kV level with Iraq are under construction.

PEDEEE's distribution lines reach nearly all of the population, achieving an electrification rate of almost 100 per cent.

Low electricity prices have contributed to the rapid growth in electricity demand and to some extent to inefficient electricity use. Currently a block tariff system is being used where price depends on the amount of electricity being used. As of 2013 Syria had one of the cheapest electricity prices in the region, ranging from US$0.003/kWh to US$0.036/kWh

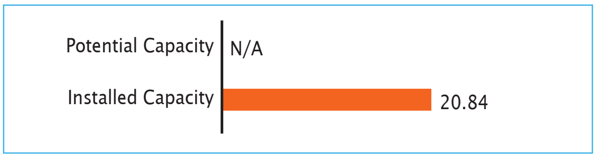
In September 2012, the Minister of Electricity announced plans to boost generating capacity by an additional 1.5 GW over the next several years, but like most of the projects in the country, they lack access to international capital. Syrian officials announced that the schedule for the construction of 1 GW in new generating capacity (from four new 250 megawatt power plants) would be delayed until the end of 2012, and as of January 2013 there has been no reported progress.[7]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Syria is up to 10 MW. Installed capacity of SHP is 20.84 MW while the potential capacity is not available (Figure 2).

FIGURE 2

SHP capacity in Syria (MW)



Source: Muhamed Almahmod and Samer Ahmed[5]

Hydropower is the only significant renewable energy contributor to the country's electricity supply, providing between 2,000 GWh and 4,000 GWh per year, depending on precipitation levels. There are four SHP plants with an overall installed capacity of 20.84 MW. There is some potential for further development of SHP, though further research has to be conducted.

TABLE 1

SHP Installed in Syria

Station	River	Installed capacity	Commissioning year
Takkia	Barada	1 MW	1906
Alasi	Alasi	2.8 MW	1932
Barada Valley	Barada	8 MW	1957
Alrastan	Alasi	9 MW	1962
Total		**20.84 MW**	

Source: Muhamed Almahmod and Samer Ahmed[5]

Renewable energy policy

Although the Syrian Arab Republic relies on locally produced traditional energy resources like oil and gas, other renewable resources exist such as wind and solar energy. There are hydro energy resources available on the Euphrates River with an annual production capacity of 1.4-2.1 TW, in addition to other stations and dams available. Estimates of the main biomass resources for the year 1999 show that there are about 577,365 tons of dry animal dung; 360,000 tons of dry chicken droppings; 230,000 tons of dry human waste; and 34,000 tons of dry kitchen residues are available every year. Annually, 357 million m^3 of biogas could be produced in Syria.

The Government has developed an updated Renewable Energy & Energy Efficiency Master Plan in collaboration with German Technical Cooperation Agency (GTZ). The plan runs until 2030 and comprises renewable expansion targets for each five years from 2010. The plan has been drafted and needs to be approved by the responsible government entities.

Syria adopted progressive measures in 2011 to attract interest in renewable energy. It has opened its market for private developers, adopted feed-in tariffs (FITs) and a net metering policy, authorized the business-to-business sale of renewable electricity, and announced tenders for public competitive bidding to develop the first large-scale wind projects. However, due to the ongoing conflict, all activities have been paused and the Syrian Government has not had the chance to implement the newly introduced policies.[7]

Barriers to small hydropower development:

The assessment of the hydro-energy resources shows:

- Syrian hydropower resources are limited by the low precipitation and river flow. Most of the available hydropower potential has been used.
- The current ongoing conflict has put almost all development plans on halt.
- Further studies have to be carried out to analyse the scope for micro-hydropower. These can be stand-alone power plants or linked together to form a mini grid in the region assuming the period of availability of water justifies the investments.[9]

3.5.9 Turkey

Alaeddin Bobat, University of Kocaeli; Öztürk Selvitop, Ministry of Energy and Natural Resources of the Republic of Turkey

Key facts

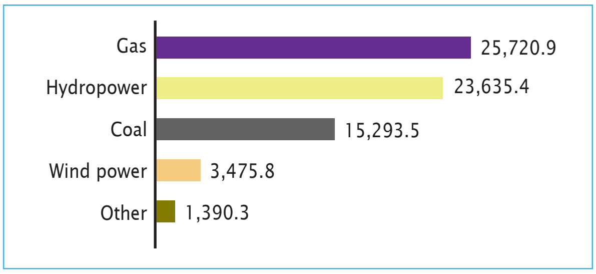
Population	77,695,904[1]
Area	783.043 km[2]
Climate	Turkey is semi-arid with some extremes in temperature. Its coastal areas have a Mediterranean climate with hot, dry summers between June and August with temperatures reaching 35°C. In the higher interior Anatolian Plateau, the winter months between December and February can be very cold, with temperatures going down to –7°C. The average temperature in 2014 was 14.9°C.[2]
Topography	Dominated by the central Anatolian Plateau that covers much of the country apart from narrow coastal plains on the Aegean and Black Seas, the highest point is Mount Agrı at 5,166 m. There are also more than a hundred peaks higher than 3,000 m. Turkey lies within a seismically active area.[3]
Rain pattern	The average annual precipitation is 643 mm, ranging from 250 mm in Central Anatolia to over 2,500 mm in the coastal area of the north-eastern Black Sea. Approximately 70 per cent of the total precipitation falls during between October and April.[4]
General dissipation of rivers and other water sources	The Euphrates and the Tigris rise in the high mountains of north-eastern Anatolia and flow through Turkey before entering Syria. Together, they account for approximately one-third of Turkey's water potential. Many rivers rise and discharge into seas within Turkey's borders. The rivers discharging into the Black Sea are the Sakarya, Filyos, Kızılırmak, Yesilırmak and Çoruh; discharging into Mediterranean Sea are the Asi, Seyhan, Ceyhan, Tarsus and Dalaman; discharging into the Aegean Sea are the Büyük Menderes, Küçük Menderes, Gediz and Meriç; and discharging into the Sea of Marmara are the Susurluk/Simav, Biga and Gönen.[2]

Electricity sector overview

As of 2014 total installed capacity was 69,516 MW, 37 per cent from natural gas fired power plants, 34 per cent from hydropower, 22 per cent from coal and 5 per cent from wind (Figure 1).[5] Projected capacity is estimated at 110,000 MW by 2023.[6]

FIGURE 1

Installed capacity in Turkey by source (MW)



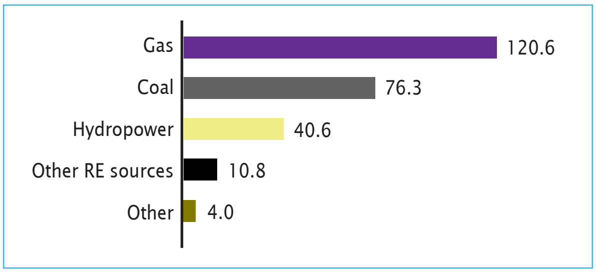
Source: TEIAS[5]

In 2014, total electricity generation was 251.9 TWh. Natural gas had the dominant role contributing approximately 47.9 per cent, coal 30.27 per cent, hydropower 16.1 per cent and wind and other renewable sources 4.3 per cent (Figure 2).[5]

Consumption in 2014 was approximately 257.2 TWh with 5.3 TWh imported. The electrification rate across the country is 100 per cent. The demand for energy has been growing an average of 5.7 per cent annually since 2003 and is expected to grow by approximately 6 per cent per year until 2020.[7]

FIGURE 2

Annual electricity generation in Turkey by source (TWh)



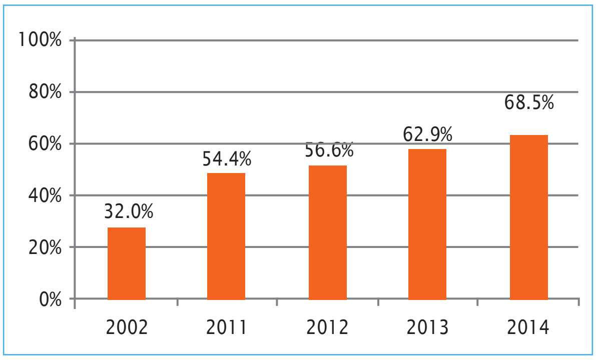
Source: TEIAS[5]

The share of installed capacity and electricity generated from privately-owned plants has been rising steadily since 2002 (Figures 3 and 4). At the end of 2014, the share of energy produced by the private sector reached 72.1 per cent.[8] The remaining 28 per cent was produced by the state-owned Electricity Generation Corporation (EUAS).[5]

In 2014, around 68.5 per cent of Turkey's installed capacity was privately owned. EUAS had a share of 31.5

FIGURE 3

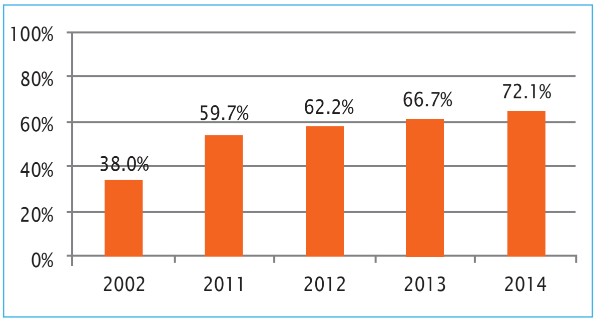
Share of private ownership in Turkey by installed capacity 2002-2014 (%)



Source: Energy Outlook on Turkey[9]

FIGURE 4

Share of private ownership in Turkey by generation 2002-2014 (%)

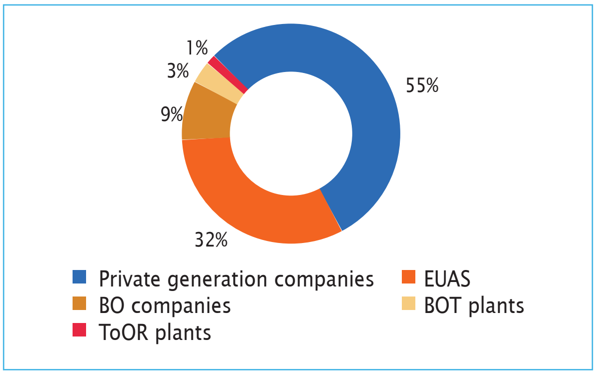


Source: Energy Outlook on Turkey[9]

per cent, private generation companies 54.9 per cent, build and operate (BO) companies 8.8 per cent, build-operate-transfer (BOT) plants 3.3 per cent, and plants whose operation rights have been transferred (ToOR) 1.4 per cent (Figure 5).[9,10] In addition, the privatization of 21 distribution companies was finalized in 2013 and the process of privatizing a significant number of state-owned power plants is still ongoing.

FIGURE 5

Installed capacity by ownership (%)



Source: Energy Outlook on Turkey[9]

The main law applicable to the Turkish electricity market is the Electricity Market Law number 6446 (EML) introduced 30 March 2013. 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 Turkey.[11] The implementation and interpretation of new mechanisms introduced by this legislation are outlined by secondary legislation. The most notable piece of secondary legislation in this area is the Electricity Market Licensing Regulation (Licensing Regulation) published in the Official Gazette on 2 November 2013. The Licensing Regulation introduces a new licensing regime, intended to reform and stimulate the market.[12]

In Turkey, there are two main government authorities regulating the electricity market, the Ministry of Energy and Natural Resources (MENR) and the Energy Market Regulatory Authority (EMRA). Electricity transmission in Turkey is managed by TEIAS while distribution is divided into 21 separate regions. Each region is controlled by private distribution companies each with distribution licenses from EMRA. Electricity supply in Turkey is undertaken by numerous private sector companies, as well as the state-owned Turkish Electricity Trading and Contracting Company (TETAS). Each supplier must obtain a supply license from EMRA.

Prior to the introduction of the EML, TEIAS was both system and market operator. Currently, however, TEIAS operates solely as the transmission system operator (TSO) while a new company, the Energy Markets Operation Company (EPiAS) was established as market operator. EPIAS has a shareholder structure comprising 30 per cent TEIAS, 30 per cent Istanbul Exchange Market (BIST) and 40 per cent private sector. EPIAS is responsible for organizing the energy exchange market operations, as a market operator, to operate the spot market and to allow the private sector to make forecasts much more easily in order to plan their investments.

Turkey has been experiencing a rapid demand growth in all segments of the energy sector for decades. Recent forecasts indicate that this trend will continue in the forthcoming decades in parallel to the economic and social development. The main target of the Turkish energy policy has been to provide timely, reliable and sufficient energy with affordable prices in an environmentally sound manner, in order to foster economic growth and social development.

The main pillars of the country's energy policy are:

- Prioritizing energy supply security activities through a well-balanced resource diversification to minimize negative effects of import dependency;
- Reforming and liberalizing the energy sector to enhance productivity and economic efficiency;
- Sustainable exploitation of energy sources and investing in all stages of the energy chain taking into account the environmental concerns;
- Acting as an important axis for projects aiming at transportation and trade hydrocarbons in the context of the Energy Corridor and Terminal concept;

- Intensifying research and development on energy technologies.

The Electricity Market and Security of Supply Strategy Paper is a road map of market reform in electricity including the next steps for wholesale market design, privatization, supply security, demand side participation and energy efficiency.[13] It sets targets for the share of primary energy sources in the electricity generation mix with particular regard to the utilization of renewable energy sources.

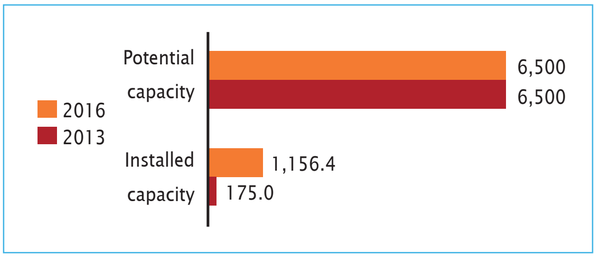
EMRA regulates transmission, distribution and retail tariffs. In the first period of 2013 (1 January to 30 June), household consumers below 1,000 kWh paid on average TL 0.357/kWh (US$0.197) electricity while consumers over 15,000 kWh paid an average of TL 0.353 (US$0.195). In the same period industrial consumers below 20 MWh paid an average of TL 0.282/kWh (US$0.155) while consumers in the largest consumption band, 150 GWh and above, paid an average of TL 0.217/kWh (US$0.120). In 2014, the prices in the first and second period were TL 0.354 (US$0.195) and TL 0.374 (US$0.206) respectively for household consumers while they were TL 0.234 (US$0.129) and TL 0.236 (US$0.130) for industrial consumers respectively.[14,15] In January 2015, the average tariff for households was approximately TL 0.31/kWh (US$0.171), excluding taxes.[16]

Small hydropower sector overview and potential

Although there is no legal definition in the country, hydropower plants with an installed capacity of below 10 MW are widely considered small hydropower (SHP) in Turkey.[6,17] Installed capacity at the end of 2014 was approximately 1,156.4 MW with a total economically feasible potential capacity estimated at 6,500 MW indicating approximately 17.8 per cent has been developed.[5,18,19] In comparison to data from the 2013 report, the potential capacity remained the same while installed capacity has increased significantly. But this is due to an inaccurate assessment of capacity reported previously (Figure 6).[20]

FIGURE 6

SHP capacities 2013-2016 in Turkey (MW)



Source: Various[5,18,19,20]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

At the end of 2014 there was a total of 254 SHP plants that generated 2.6 TWh of electricity combined. In 2014 there was a total of 531 hydropower plants of all sizes with a total installed capacity of 22,475 MW generating an annual average of 79.912 TWh. SHP accounts for approximately half of all hydropower plants but only 5.1 per cent of installed capacity.

The theoretical, technical and economical hydropower potential is 433 TWh, 216 TWh and 165.5 TWh respectively.[21,22] According to EMRA's Progress Report of January 2015, there were 190 SHP plants under construction with a total capacity of 986.7 MW.[23] Additionally, 151 SHP plants with a total capacity of 705 MW are in the planning stage of the State Hydraulic Works (DSI), which is the affiliated institution of the Ministry of Forestry and Water Affairs.[24]

As of June 2015 there were 307 SHP plants in the pre-license stage of development with combined installed capacity of 1,352.8 MW. In addition there are a further 465 plants with a combined capacity of 2,267.5 MW, including those that are operational and that have received a generation license (Table 1).

TABLE 1

SHP plants (below 10 MW) by stage of development (as of June 2015)

License type	Stage	Capacity (MW)	Number of power plants
Pre-License	Application stage	974.7	219
	Evaluation stage	45.7	14
	Granted	332.4	74
Generation license*	Granted	2,267.5	465
Total		**3,620.3**	**772**

Source: EMRA
Note: An asterisk (*) means data includes power plants that are in operation.

Most local banks and international finance institutions are willing to finance SHP projects under reasonable conditions. Under the Private Sector Renewable Energy and Energy Efficiency Project (PSREEE) of the World Bank, for example, 13 SHP projects with a total capacity of 86.24 MW have been financed since 2009.[25]

Renewable energy policy

The Government plans to have renewable energy sources account for 30 per cent of the total electricity generation mix by 2023. Additionally there is also a commitment to reduce the amount of energy consumed per unit of gross domestic product (GDP) by 20 per cent between 2008 and 2023. The Energy Efficiency Law was enacted in 2007 and Energy Efficiency Strategy Paper (2012-2023) was issued in 2012 in order to foster efficient use of energy along the supply-demand chain.[26,27]

Since 2010, the strategies followed by Ministry of Energy and Natural Resources (MENR) for increasing the share of renewable energy within the energy mix include:

- Precautions taken for the completion of licensed projects within the projected terms for renewable energy resources of economic value;
- Production planning prepared considering developments within the renewable energy field, in line with advances in technology and the arrangements within current legislation;
- Precautions taken for the maximum utilization of hydropower potential, as is economically feasible, and for the integration of this potential into the national economy through the private sector;
- Increase cooperation with studies conducted for the development of water resources as economically feasible for electricity generation on the basis of integrated approaches to meet changing consumption demands;
- The criteria for the economic analysis of hydropower plants will be evaluated according to present day standards;
- Acceleration in the number of studies required for the growth of the electricity transmission system that would allow for the connection of a higher number of intermittent energy technologies such as solar and wind energy power plants;
- The protection of geothermal resources during utilization, including their sustainability in terms of renewal and regeneration;
- Plans to open up areas for geothermal development, where suitable for electricity production, in order to accelerate private sector participation;
- Emphasis given to technology development studies in the field of renewable energy resources.

The MENR Strategic Plan 2015-2019 also includes installed capacity targets for different types of renewable energy sources (Table 2).[28]

TABLE 2

Installed capacity targets for renewable power plants

Resource type	Installed capacity (MW)		
	2015	2017	2019
Solar power	300	1,800	3,000
Geothermal	360	420	700
Biomass	380	540	700
Wind power	5,600	9,500	10,000
Hydropower	25,000	27,700	32,000

Source: MENR Strategic Plan (2015-2019)[17]

Turkey has also joined the United Nations Framework Convention on Climate Change and ratified The Kyoto Protocol on 28 May 2009. Additionally, the Government has implemented several actions against any negative environmental impact since 2010 including:

- The promotion of the usage of renewable energy resources and the effective use of energy and clean coal technologies;
- The reduction of greenhouse gas emissions;
- The utilization of biomass/biogas potential (in infrastructure facilities for water, waste water and solid waste);
- Increase in the effectiveness of control and supervision for compliance with sustainable mining and sustainable environmental principles in mining operations;
- Training and public awareness of climate change and environmentally friendly energy technologies.

Currently, there are two main laws in Turkey promoting Renewable Energy, the Electricity Market Law No. 6446 (together with the related secondary legislation) and the Utilization of Renewable Energy Resources for the Purpose of Generating Electrical Energy Law No. 5346 (the Renewable Energy Law), which is the main promotion law.[29]

The Renewable Energy Law was enacted in 2005 (and amended in 2011) according to which all renewable energy based power plants commissioned before 31 December 2020 will be eligible to receive feed-in tariffs (FITs) for the first 10 years of their operation. For SHP plants this FIT is set at US$0.073 per kWh. In addition, if the mechanical or electro-mechanical equipment of the power plant is being manufactured locally, a premium will be added to the FITs during the first 5 years of operation.

In order to encourage investments in renewable energy within the framework of the EML (and related secondary legislation) electricity generation plants based on renewable energy are supported by the following mechanisms:

- Payment of only 10 per cent of the total licensing fee;
- Exemption from payment of annual license fees for the first eight years of operation;
- Priority for system connection;
- Purchasing electricity option;
- Exemption from licensing and establishing a company requirements (this item is valid only for renewable based power plants having maximum 1 MW installed capacity).

In the prior version of the EML renewable energy based power plants of below 500 kW installed capacity were exempted from license applications and the requirement to establish a company. With the current EML the upper limit was increased to 1 MW while the Council of Ministers is authorized to increase this upper limit up to 5 MW. Additionally, the Last Resort Supply concept was also introduced to bring a universal service obligation to the supply companies.

Distribution companies are required to offset the consumption and production amounts and buy the excess energy at the prices specified in the RES Mechanism for 10 years. Since the RES portfolio is run by the market operator, the market operator is authorized by EMRA to ask for a letter of bank guarantee to run the mechanism in an efficient way.

Legislation on small hydropower

As of July 2008, environmental impact assessments (EIA) are required for any hydropower projects with an installed capacity of 0.5 MW to 25 MW.

Additionally, as per the Renewable Energy Law No. 5346, Article 7, projects "establishing an isolated electricity generation plant and grid supported electricity generation plant by utilizing hydraulic resources with a maximum installed capacity of 1000 kW for meeting solely their own demands, shall not be claimed to pay the amounts of service for the projects, of which final designing, planning, master planning, preliminary surveying and first auditing were prepared by either General Directorate of State Water Works or General Directorate of Renewable Energy."

Barriers to small hydropower development

One barrier to SHP development is that the Renewable Energy Law No. 5346 applies to SHP or hydropower production facilities having a reservoir area less than 15 km^2 making no limitation regarding installed capacity. This encourages the private sector to move towards investment in large hydropower systems for the potentially higher profits. Additionally, environmental insensitivities in the stages of construction and operation of facilities and public backlash could jeopardize investment opportunities.[30]

CHAPTER 4
Europe

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4.1 Eastern Europe

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Introduction to the region

There are 10 countries discussed in this section: Bulgaria, Czech Republic, Hungary, Poland, Romania, Slovakia, Russian Federation, Belarus, Ukraine and the Republic of Moldova (see Table 1). However, while the first six of them are members of the European Union (EU), integrated within the EU structures, such as its legislation system and development strategy, the situation of others remains highly differentiated.

Despite Belarus seeking multilateral cooperation with the EU, the economic and ethnic ties between Belarus and the Russian Federation (Russia) are strong and are expected to be preserved. Its economy is also heavily dependent on Russian supplies, as 95.5 per cent of its electricity is generated using imported natural gas.

On the other hand, Ukraine and the Republic of Moldova are making significant efforts to join EU while breaking their traditional links with Russia. Both countries are ethnically and politically inhomogeneous. As their current policies do not reflect a major national consensus, severe conflicts with global international context have emerged in their Eastern regions. This only deepens the economic crisis, particularly in the Ukrainian power sector, where they suffer from the occasional shortages of energy carriers. At the same time, the electrical power systems of both countries still work in parallel with the United Energy System of Russia.

Although discussed in this regional report, only 23 per cent of the territory of Russia is located within the geographic sphere of Europe. The climate of this 23 per cent within Europe is as follows: sub-Mediterranean near the Black Sea, continental in the dry steppes of the Caspian region and in most of the East European Plain, subarctic in the far north, and finally, subarctic in Siberia and tundra in the polar north. A feature distinguishing Russian hydropower sectors from most other countries in that region is represented by large hydroelectric schemes erected at grand rivers in Eastern Europe and Siberia, heavily prevailing over small hydropower (SHP) installations. Water storage of vast capacity such as reservoirs have impeded on the development of pumped storage projects for a number of years, thus slowing down the growth of Ukrainian efforts presently.

Apart from Russia, the climate in the region may be described as mild, with features of transitional climate in Poland, and continental in Belarus and Ukraine. Furthermore, Mediterranean-like climate prevails in large portions of the Black Sea coast.

TABLE 1

Overview of countries in Eastern Europe (+/– % change from 2013)

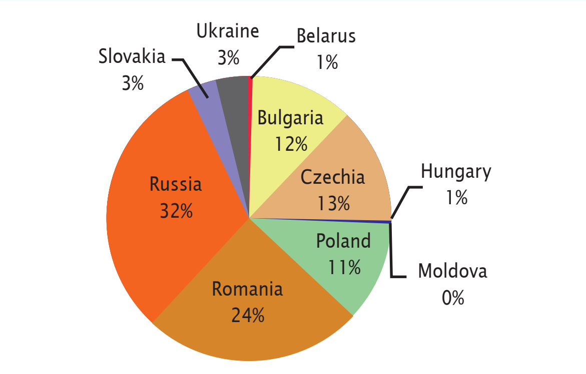
Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (GW)	Electricity generation (TWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Belarus	9.47 (-1.7%)	24 (-2pp)	100	9.33 (+10.4%)	34.74 (+5.4%)	26 (+75.3%)	121 (+169%)
Bulgaria	7.25 (+3.1%)	27 (-3pp)	99.4	13.56 (+17.9%)	43.78 (-2.3%)	3,191 (+123.0%)	4,795 (-5.2%)
Czechia	10.54 (+3.5%)	27 (+1pp)	100	21.92 (+9.2%)	79.89 (-8.8%)	2,261 (+114.0%)	2,928 (+37%)
Hungary	9.85 (-1.1%)	29 (-3pp)	100	8.90 (-12.0%)	29.30 (-18.6%)	56 (+4.1%)	302 (+36%)
Republic of Moldova	3.55 (-3.1%)	55	100	3.00 (+44.5%)	4.49 (+31.6%)	64 (0.0%)	310 (-2.5%)
Poland	38.48 (+0.2%)	39 (0)	100	38.12 (+2.0%)	156.57 (-4.0%)	977 (+1.8%)	2,250 (-3.4%)
Romania	19.94 (-8.7%)	46 (+3pp)	100	23.82 (+15.5%)	59.65 (-1.2%)	6,629 (+2.4%)	18,450 (-5.5%)
Russia*	146.27 (+3.2%)	26 (-1pp)	100	232.45 (+6.6%)	1,026.85 (+0.7%)	47,855 (+2.0%)	160,171 (-3.8%)
Slovakia	5.42 (-1.2%)	46 (+1pp)	100	8.08 (-2.9%)	27.25 (-3.2%)	2,536 (+5.7%)	4,572 (+24.1%)
Ukraine	45.43 (+1.3%)	31	100	55.4 (+1.4%)	182.41 (+5.5%)	5,854 (+24.3%)	9,093 (-30.8%)
Total	**296.20 (+1.2%)**	—	—	**414.55 (+6.0%)**	**1,644.92 (+0.2%)**	**69,393 (+8.5%)**	**202,992 (-4.7%)**

Sources: Various[1,2,3,4,5,6,7,8,9,15]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. (*) Totals for electricity capacity and generation may vary due to inclusion or exclusion of autonomous or other regions; in this report the data was excluded as per UES System Operator reports.[15]

Moderate precipitation (around 600 mm annually) is typical for the region, though it may exceed 1,000 mm annually in mountains, and fall below 400 mm annually in some areas of the central and east European Plain. Due to various physiographic conditions, the hydropower potential density is highly differentiated. The optimal conditions are encountered in Romania and Bulgaria, while significant untapped technical potential still exists in Ukraine. With 48 GW installed, Russia merely uses 21 per cent of its vast economical hydropower potential (10 per cent of the total technical potential).

FIGURE 1

Share of regional SHP by country



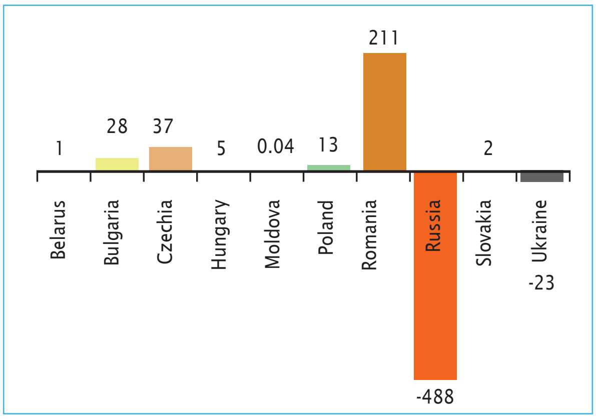
Source: *WSHPDR 2016*[5]

Hydropower is present in all countries of the region although its potential and utilization rate are highly varied. The same could therefore be said for the SHP sector. If environmental constraints are taken into account, the SHP potential of Belarus and Hungary may be considered small and very small, respectively. Before World War II, numerous water plants (mills, forges, granaries, but also hydroelectric plants) were in operation in such territories now belonging to Czechia, Poland and some other countries. In the 1930s, numerous state-owned SHP plants were erected also in the Soviet territory. After a brief post-war revival, most of the SHP plants in the region fell into economic plight and physical degradation as they were unable to compete with large power plants, including the large hydropower plants which were intensively developed in the 1950s and 1960s. In the mid-1980s, the restoration of SHP started in Czechia and Poland resulting in around 1,600 and 760 SHP plants (< 10 MW), respectively. Some other countries joined this trend in 1990s as well. Due to different economic conditions, however, the progress of the countries in the Commonwealth of Independent States (CIS) was much slower. Following the country report, in 2014, the number of Russian SHP plants with capacity below 10 MW was still as low as 110.[5]

Romania and Russia together account for over 50 per cent of the regional share of installed SHP (Figure 1). Between *WSHPDR 2013* and *WSHPDR 2016* installed SHP capacity has decreased by 8 per cent from 2,735 MW to 2,521 MW, largely due to recent release of more accurate data on Russian SHP. Meanwhile, SHP increased in Bulgaria, Czechia and Romania, balancing the drop of overall installed capacity of the region (Figure 2).

FIGURE 2

Net change in SHP (MW) from 2013 to 2016 for Eastern Europe region



Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative or positive net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.

Small hydropower definition

All EU member states are required to submit annual reports on SHP generation as divided into two installed capacity categories: up to 1 MW and in the range between 1 MW and 10 MW. In some cases, data on SHP plants with capacity below 100 kW is also available. These thresholds could be used for the distinction between small, mini and

TABLE 2

Classification of SHP in Eastern Europe

Country	Small (MW)	Mini (kW)	Micro (kW)	Pico (kW)
Belarus	≤ 10	—	—	—
Bulgaria	≤ 10	—	—	—
Czechia [a]	≤ 10	≤ 1,000	≤ 100	—
Hungary	≤ 5	—	—	—
Republic of Moldova	≤ 10	—	—	—
Poland	≤ 5	—	≤ 40	—
Romania [a]	≤ 10	≤ 500		—
Russian Federation [b]	≤ 25 (30)	—	—	—
Slovakia [a]	≤ 10	≤ 1,000	—	—
Ukraine	≤ 10	≤ 1,000	≤ 200	—

Sources: Various [5,6,12]
Notes:
a. Since micro/mini-installation term is not used in the legislation, different rules have been introduced for the plants with capacity below and over the threshold indicated.
b. The 30-MW threshold was used in the Soviet era legislation. The threshold of 25 MW is ever more often encountered in the current legal documents (see country report).

micro installations, especially when it is not declared in the legislation governing the SHP support schemes. A much higher SHP threshold has been preserved in Russia till this present day (Table 2).

Regional SHP overview and renewable energy policy

All countries in the region have implemented policies aimed at promoting renewable energy sources (RES). While diversification of energy sources is the main goal for Belarus and Moldova, special efforts against climate change are demanded by EU (2009/28/EC RES Directive).[7] Additionally, as large hydropower encounters even more barriers, including environmental, numerous countries have thus taken proactive steps to instead focus on the development of other renewable energy sources, such as wind and solar power. Intense investments in the energy storage capacities and grid infrastructure are needed to secure stability of the national grids. At the same time, disappointments with EU climate policy as well as the resistance to further efforts aimed at increasing the contribution of renewable energies to the national energy mix are recently growing among some of the new EU members.

An important method of increasing stability and safety of national grids is cross-border collaboration between system operators. All EU transmission system operators (TSOs) are members of the European Network of TSOs for Electricity (ENTSO-E).[8] The Network was established and given legal mandates in 2009 by the EU's Third Package for the Internal Energy Market, which is composed of two European directives and three regulations.

The TSOs of EU members analysed in this section, along with the Power System of Western Ukraine, all operate within the Continental European synchronous area (previously: UCTE), whereas the United Energy System of Russia (UES) is synchronized with the rest of Ukrainian power grid. The UES is also networked with the power systems of Belarus, Moldova and the ENTSO-E Baltic synchronous area. The ENTSO-E competence and activity goes far beyond the developing and updating of network codes. The Pan-European and regional ENTSO-E initiatives are also included in the biennially updated Ten Year Network Development Plan (TYNDP), which forms a basis for the Regional Investment Plans and Annual Work Programmes.

The TSOs of EU member states described in this section are active in three ENTSO-E regional groups (Baltic Sea, Continental Central East and Continental South East one). An interesting regional initiative of Polish and some Scandinavian TSOs is the implementation of the so-called DC loop flow mechanism for energy transition between synchronous areas.[9] The range of developed regional tools on operational security also includes the ENTSO-E Awareness System (EAS) and the set of Regional Security Coordination Initiatives (RSCIs). On the market side, regional TSOs have cooperated to create a common auction office for the allocation of cross-border transmission capacity.

The development of the European Electricity Market is a joint effort of national TSOs and energy regulators coordinated by ENTSO-E and the Agency for the Cooperation of Energy Regulators (ACER). They work in close collaboration with various EU and national institutions. One of the key contributors to the development of the internal energy market is ENTSO-E's Central Information Transparency Platform, which is in constant improvement since its creation in 2015. European Electricity Market project is fairly advanced and countries in the Central East region are advancing towards gaining access to its mechanisms. Following the 2015 ACER report,[10] the Electricity Price Coupling mechanism has been implemented in five countries of the region (Poland, Czechia, Slovakia, Hungary and Romania).

Due to different surface areas and physiographic features, the SHP potential of the region is very diverse, with different measures of exploitation (Table 3). Czechia and Romania have already tapped onto a major fraction of their economic potential while only a small portion has been utilized in the other countries of the region. As detailed below, a mere 0.2 per cent of the technically feasible potential for installations of up to 30 MW has been tapped in Russia. This ratio may be lower if a 10 MW threshold for SHP definition is applied. An even lower ratio comes from the data of the Republic of Moldova. However, it should be noted that while uncertainties in the assessments of Russian potential are higher than the total potential of other countries in the region, and there are plans to triple the installed capacity until 2020, little progress may be expected in Moldova. No major developments are expected in Hungary either, where the authorities have set their economic potential evaluation of 28 MW as the ultimate target for the country. On the other hand, Belarus has ambitious plans to invest both in small and large hydro.

By adopting RES promotion directives, all EU members are compelled to implement a mechanism supporting the renewable energy sector, including simplified administrative procedures, preferential access to the grid and numerous economic incentives. The most popular incentives for investors include low cost credits, access to various investment support funds (often using the EU cohesion-means) and lower fees or taxes. The preferential system of remuneration for delivered electricity is usually represented by tradable green certificates (Poland, Romania), feed-in tariffs (FITs) or green bonus systems (other EU countries of the region). A mechanism of auctions for a 15 year delivery of renewable energy is envisaged in the recently released Polish RES Law. All above-mentioned incentives have limited effectiveness if highly restrictive environmental policies are implemented at the same time, thus possibly hampering further development.

As shown in Table 3, the general situation of the sector in EU countries has deteriorated since the previous report. On one hand, the implementation of Water Framework and Natura 2000 EU Directives substantially strengthened hydropower opponents that are fighting against any

TABLE 3
SHP up to 10 MW in Eastern Europe (+/– % change from 2013)

Country	Potential (MW)	Planned (MW)	Installed capacity (MW)	Annual generation (GWh)
Belarus	250 (-)	15.7	16 (+7.3%)	30 (+7.3%)
Bulgaria	581 (+53%)	1.8	291 (+10.5%)	1,142 (+81.3%)
Czechia	465 (0%)	10	334 (+12.4%)	1,066 (–0.6%)
Hungary [a]	28 (0%)	9	19 (+37.9%)	95 (+41.8%)
Republic of Moldova	300 (-)	1.2	0.14 (+40.0%)	0.4 (-)
Poland	735 (-)	41	288 (+4.8%)	1,030 (–6.3%)
Romania	730 (0%)	N/A	598 (+54.5%)	1,031 (+61.9%)
Russian Federation [b]	N/A	N/A	214	642
Slovakia	241 (+72%)	160	82 (+2.0%)	282 (–7.0%)
Ukraine	1,140 (-)	N/A	81 (–22.1%)	251 (+0.3%)
Total	**4,469 (+27.8%)**	**238.7**	**1,923 (–29 %)**	**5,569 (+32.8 %)**

Sources: *WSHPDR 2016*,[5] *WSHPDR 2013*,[6] ESHA[7]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. The sharp increase in potential for Slovakia is due to access to more accurate data; the previous potential was assumed based on figures for installed and planned SHP. Ukraine decrease largely due to redefining SHP from < 30 MW to < 10 MW: (a) refers to capacity and potential ≤ 5 MW.

further exploitation of rivers. Several European rivers have already been preserved from damming during last decades, especially those valleys identified as Natura 2000 areas where new hydropower installations would be very difficultly (or even impossibly) built. Examples of imposed limitations include Slovakia where the erection of several large hydropower plants has remained under consideration for several years, and Hungary where only 5 to 6 per cent of the available potential is going to be exploited.

Barriers to small hydropower development

Due to global economic crisis at the beginning of the decade, rising costs of supporting RES growth, and frequent critics from the Climate Package, government economic incentives have been substantially limited during last years (e.g. Poland and Romania). Cuts are especially harmful for SHP owners and developers in some countries where access to support funds is more difficult for them than for representatives of other technologies. On the other hand, it may be argued that various fees and taxes (e.g. for civil engineering structures, for flooded areas) have often indirectly affected operation and maintenance costs. Whilst support mechanism manipulation and the introduction of head-independent water use fees have practically stopped SHP development in Romania, the situation still remains unclear in Poland.

Political commitment to develop SHP sector exists in Russia, Belarus and Ukraine. However, low prices of fossil fuels are a major challenge for the whole RES sector in Russia and Belarus. In Ukraine, the current political and economic instability may discourage numerous potential investors.

Apart from the aforementioned barriers, most country reports also indicate lengthy administrative procedures, especially those aimed at safeguarding environment. Additionally, master plans for development of the sector are usually missing, evoking a high risk on the extensive effort of a developer who may end up with a negative result. A positive exception from this trend is Slovakia where a plan for harnessing the national hydropower potential already exists. However, even in Slovakia, lengthy procedures and strong opposition from green NGOs are present till this day.

The shared background that the countries in Eastern Europe have, made by long administrative procedures and economic problems, results in poor investments in hydropower. The sector is often perceived solely as a moderate source of green energy, providing incomes to investors at the cost to the environment. The multipurpose character of SHP installations and the related numerous benefits for water management, the environment, as well as local power grids, are usually disregarded. This viewpoint, fomented by highly influential NGOs, should be strongly counterbalanced by SHP experts. In Poland, Czechia and Romania private SHP companies have recently gathered together in national hydropower associations. Similarly in Poland, the public side of the small hydro sector has its own NGO as well. All associations do their best marketing the sector among the society and ask for friendly SHP legislation with Governments. Until the end of 2014, Polish and Romanian associations contributed to the (now closed) European Small Hydropower Association (ESHA) which was established as an umbrella organization, lobbying for the sector at the European level. While bilateral links between ESHA members have been preserved, it is still quite clear that restoring coordinated activity is highly needed.

4.1.1 Belarus

Zhanna Zenkevich, Ministry of Energy

Key facts

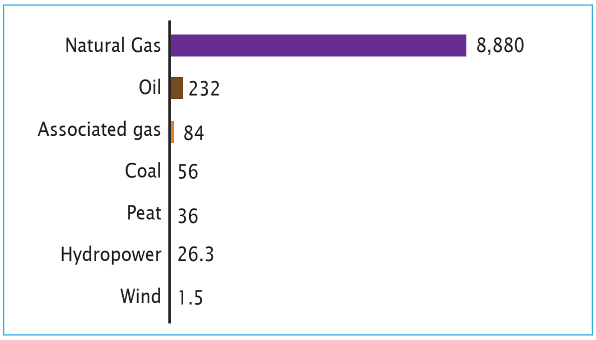
Population	9,470,000[1]
Area	207,599 km[2]
Climate	The climate has mild to cold winters with average January temperatures ranging from −4°C in the south-west (Brest) to −8°C in the north-east (Vitebsk), and cool and moist summers with an average temperature of 18°C. The country is in the transitional zone between continental and maritime climates.[2]
Topography	The country is landlocked, relatively flat and contains large tracts of marshy land. In the west and north-west of the country are mountain ridges with the highest peak being Mount Dzyarzhynskaya at 345 m. About 40 per cent of Belarus is covered by forest.[2]
Rain pattern	Belarus has an average annual rainfall of 500 to 800 mm. The wettest seasons are summer and autumn. The most precipitation falls in the central and north-western parts of the country.[2]
General dissipation of rivers and other water sources	Belarus is supplied with sufficient water resources to meet the current and future consumption needs. It has around 20,800 rivers, 10,800 lakes, 153 water reservoirs and 1,500 ponds. The total length of rivers is 90,600 km; the rivers of the Black Sea (Dnieper, Sozh, Pripyat) and Baltic Sea (Western Dvina, Neman, Vilia, Western Boug) basins collect on average 55 per cent and 45 per cent of the accumulated river runoff, respectively.[2]

Electricity sector overview

Electricity generation in Belarus is predominantly supplied through thermal power using various fuel sources, with the vast majority coming from natural gas (95.2 per cent), oil (2.5 per cent), associated gas (0.9 per cent), coal (0.6 per cent) and peat (0.5 per cent). Installed capacity in 2015 was 9,326 MW, with 9,298 MW of thermal power stations, 26.3 MW of hydropower stations and 1.5 MW of wind power (Figure 1).

FIGURE 1

Installed electricity capacity by sources in Belarus (MW)



Source: Ministry of Energy Republic of Belarus[3]

For installed capacity, 91.9 per cent is based on large and medium thermal power stations and owned by Belenergo, a vertically integrated state-owned utility. Another 7.7 per cent of medium and mini thermal power stations are owned by different entities. Lastly, hydropower and wind represent 0.3 per cent and 0.02 per cent of total capacity respectively.

The electrification rate in Belarus is 100 per cent.[3]

In 2013 electricity generation was 31,507 GWh.[3] Out of 34,736 GWh generated in 2014, 34,602 GWh were generated by thermal power plants. The remainder came from renewable energy sources: hydro 121 GWh, wind 11 GWh and solar 2 GWh. An additional 3,826 GWh were imported.[10]

Electricity tariffs in 2013 were 0.14 US$/kWh for industrial and governmental organizations, US$0.11/kWh for street lighting and railway transport, US$0.07/kWh for households.[3]

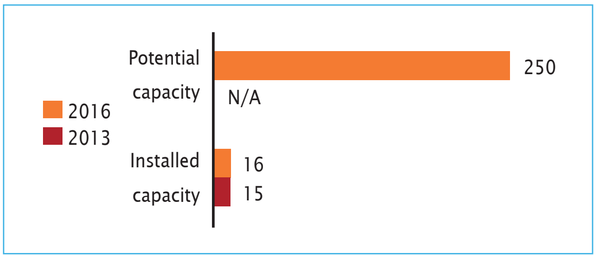
Small hydropower sector overview and potential

The Belarus definition of small hydropower (SHP) is up to 10 MW. Installed capacity of SHP in Belarus is 16.1 MW.[3] Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 7 per cent (Figure 2).

The last SHP evaluation took place in 2010. The gross theoretical SHP potential was evaluated to be 850 MW. The technically and economically feasible potential assessed to be 520 MW and 250 MW, respectively. This indicates that approximately 6 per cent of the available economic potential is exploited.[8] Currently, there are 41 SHP plants in operation with an overall capacity of 16.1 MW, 22 of which are operated by Belenegro (9.4 MW combined).

FIGURE 2

SHP capacities 2013-2016 in Belarus (MW)



Sources: *WSHPDR 2013*,[5] Ministry of Energy, Republic of Belarus[3]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016.*

The 2010 Decree of the Council of Ministers (No. 1838) approved a programme for the reconstruction of hydropower plants in Belarus.[6] The programme, which began in 2011, sought to rehabilitate 16 hydropower plants by the end of 2015. Of those plants, which have a combined total capacity of 102 MW, three are micro power plants (installed capacity under 0.1 MW), nine are SHP plants (installed capacity 0.1-10 MW) and four are large hydropower plants (installed capacity over 10 MW).[7] For new installations brought online under the programme, between 2011 and 2014, seven new hydropower plants were constructed with a total capacity of 18.9 MW (including one large plant of 17 MW). Currently three hydropower plants are under construction (21.75 MW, 40 MW, 0.64 MW) and six plants are in need of investment. The three plants under construction are expected to produce 390 GWh annually.

The state-owned enterprise Belenergo has developed a new project and is currently looking for investors. During 2016-2020, the company plans to develop new hydropower plants on the Neman, Dnieper and Western Dvina Rivers: Nemnovskovaya (installed capacity of 20 MW), Beshemkovichi (installed capacity of 30 MW), Orsha (installed capacity of 5.7 MW), Verhnedvinskaja (installed capacity of 20 MW), Shlovskaya (installed capacity of 4.9 MW) and Mogilev (installed capacity of 5.1 MW). Their commissioning will increase the annual production of electricity at hydroelectric power plants by 835 GWh.[3]

Renewable energy policy

On 27 December 2010 a new policy was introduced regarding renewable energy. The main objective of the policy is to diversify electricity generation sources within the 2011-2020 timeframe. A Decree made by the President of Republic of Belarus on 18 May 2015 (No. 209 – Usage of renewable resources) included plans regarding the modernization and reconstruction of existing installations of renewable energy as well as construction of new renewable energy projects. Power purchase agreements are guaranteed by the electricity supply authorities.[4]

Barriers to small hydropower development

The main SHP potential is in the northern and central parts of the country. The landscape of Belarus consists mostly of plains, so only low head power installations are feasible. In general, the future prospects in Belarus could see the construction of multiple use waterworks facilities, such as reservoirs for regulation of the water flow which are also used for electric power production, water supply, water transport and water protection. The development of small-scale hydropower calls for enacting policies to facilitate investments in this type of renewable energy. The most critical barriers to small-scale power generation in Belarus include low prices for competing fuels (namely natural gas), as well as attraction of private investors.[5]

4.1.2 Bulgaria

Milena Yanuzova and Maria Stariradeva, Control and Information Directorate

Key facts

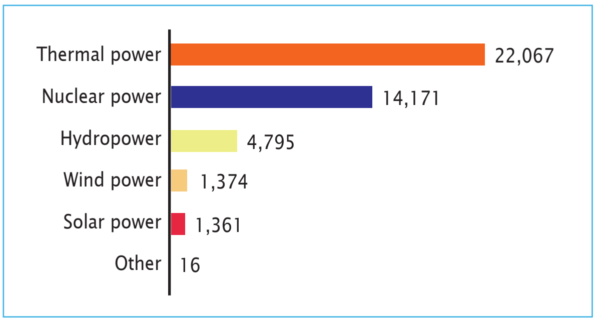
Population	7,245,677[1]
Area	111,002 km[2]
Climate	Its variable climate is predetermined by strongly contrasting continental and Mediterranean climatic zones, which. The continental influence, stronger during the winter, produces abundant snowfalls. The Mediterranean influence increases during the second half of summer and produces hot and dry weather. Winters are generally cold and snowy. The average winter temperature varies from north to south between 1°C and 4°C. In summer, temperatures in the south-west often exceed 30°C.[2]
Topography	With alternating bands of high and low terrain, more than two-thirds of the country is made up of plains, plateaus or hilly land at an altitude less than 600 m. The rest of the country is populated by mountains higher than 600 m. The average altitude in Bulgaria is 470 m.[2]
Rain pattern	The average annual precipitation in Bulgaria is about 630 mm. The northeast, the Black Sea coast and small parts of the central regions usually receive less than 500 mm.[2]
General dissipation of rivers and other water sources	The river network is formed by 1,200 rivers of various sizes, with streams and small rivers prevailing, a large portion of which are active only when there is heavy rainfall. Only 30 rivers in Bulgaria are longer than 100 km. All rivers flow into the Black and the Aegean (outside Bulgarian territory) Seas. Main hydropower resources are concentrated in rivers that originate from mountains in the south and south-west of the country: Rila, Rhodopa and Vitosha. This predetermines the great number of hydropower plants situated in the south and south-west, using water from the Iskar (368 km), Struma (290 km), Maritsa (322 km) and Mesta (230 km) river basins. More than 93 per cent of the installed hydropower capacity is located there.[2]

Electricity sector overview

Total installed capacity in 2014 was 13,563 MW. This included: lignite 4,199 MW, hydro 3,191 MW, nuclear 2,000 MW, renewable energy sources (wind, solar and biomass) 1,787 MW, black and brown coal 1,548 MW, and industrial thermal power plants 838 MW.[3] Maximum annual available net output capacity was 10,085 MW.[3] In 2013, gross electricity generation reached 43,784 GWh (Figure 1), with the largest contributor (50.4 per cent) being thermal power plants (TPP), followed by nuclear power plants (NPP) with share of 32.4 per cent. Hydropower plants also had a visible presence (11 per cent) in the electricity mix (Figure 2).[4]

FIGURE 1

Electricity generation in Bulgaria by source (GWh)

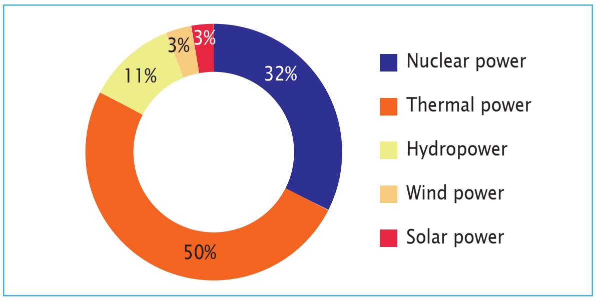


Source: National Statistical Institute[4]

Net electricity generation in 2013 was 40,055 GWh, about 7 per cent smaller than 2012. Reduction of gross electricity consumption for the second year in a row was one of the main reasons for the decrease in electricity generation in 2013, which was 2 per cent lower than the consumption in 2012. The second reason was the decreasing tendency of annual exports.[5] It should be noted, however, that data from 2014 shows that hydropower generation decreased to 4,543 GWh; this data will be used for this report's small hydropower (SHP) section and comparison.[7]

FIGURE 2

Structure of electricity generation in 2013



Source: National Statistical Institute[4]

The electrification rate in Bulgaria is 99.4 per cent. The electricity market is characterized by an overcapacity in electricity generation, which consists of two simultaneously functioning price segments: regulated (prices are regulated by the Energy and Water Regulation Commission – EWRC) and liberalized (freely negotiated prices).

In line with EU Directive 2009/72/EC and under the Energy Act, the electricity market has been fully liberalized since 1 July 2007 with a stepwise liberalization process. In 2013, free electricity market involved customers connected to the power system of high and medium voltage. The inclusion of low voltage consumers (households and small businesses) is forthcoming and thus, trades at freely negotiated prices in 2013 increased by 29.7 per cent in comparison to the previous year.[5]

All national electricity facilities are interconnected and function in a single Power System (PS) with a common operational mode and uninterrupted process of generation, transformation, transfer and distribution of electrical energy. The PS has a good widespread geographical coverage. The national transborder electricity infrastructure is also well-developed.

The Electricity System Operator (ESO) is responsible for the common operational planning, coordination and control of the Bulgarian PS and its parallel synchronous operation with neighbouring systems. ESO also manages the power transit through the national grid and runs the electricity market.

The Balancing Market, launched in 2014, covered all market participants in the chain (generation, transmission, distribution and end users). It was the most important step for electricity trade liberalization as the country now has an integral electricity tariff covering all electricity costs including energy generation, transmission, distribution, supply, support to renewable energy sources (RES), etc.

Electricity prices for household consumers in Bulgaria are regulated. The prices for households, according to the annual electricity consumption and including all taxes, levies and VAT during the period of July to December 2014, ranged between EUR 85 and EUR 91 (US$94 and US$101) per MWh,[5] whilst the prices for industry during the period of January to June 2014 ranged between EUR 63 and 115 per MWh.[5] The Regulator (EWRC) regulates electricity prices for consumers, connected to the power system of low voltage (households and small businesses) presently. The price liberalization for these consumers is forthcoming. Three big distribution companies (end-suppliers) supply electricity to the end-consumers within different parts of the country. The coverage is as follows:

- EVN Bulgaria Electricity Supply – South-Eastern Bulgaria
- Energo-Pro – North-Eastern Bulgaria
- CEZ Electro Bulgaria – Western Bulgaria.

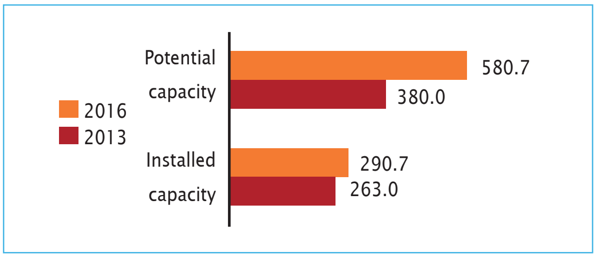
There are very small differences between the prices of the above-mentioned companies, which in turn determine inconsiderable price differences between the regions.

Small hydropower sector overview and potential

Bulgaria adheres to the generally accepted SHP definition of an upper capacity limit of 10 MW. Installed capacity of SHP in Bulgaria is 290.7 MW while the economic potential is estimated to be 580.7 MW indicating that approximately 50 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 10.5 per cent while estimated potential has increased by approximately 53 per cent (Figure 3).

FIGURE 3

SHP capacities 2013-2016 in Bulgaria (MW)



Sources: *WSHPDR 2013*,[10] ESHA[9]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The last SHP potential evaluation took place in 1998-2000. The gross theoretical SHP potential was evaluated at 1,527 GWh/year. The technically and economically feasible potential is 755 and 706 GWh/year, respectively.[6] In 2014, 221 SHP plants were in operation within the country, with a total installed capacity of 290.7 MW. 159 SHP plants (mostly privately owned) with a total capacity of 194 MW were installed after 2000.

TABLE 1

SHP allocation by REP

REP	Number of plants	Installed capacity (MW)
North-West	54	64.0
North Central	17	17.3
North-East	3	3.7
South-West	86	120.6
South Central	50	67.4
South-East	11	17.6
Total	**221**	**290.7**

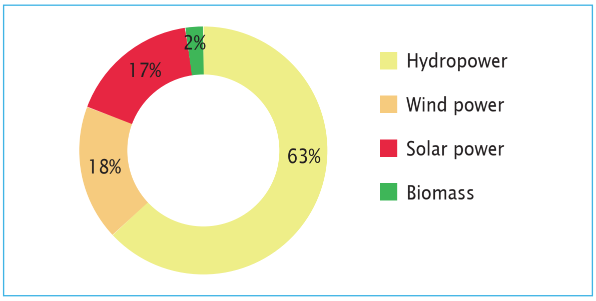
Source: Sustainable Energy Development Agency[7]

Bulgaria is divided into six Regions of Economic Planning (REP): North-West, North Central, North-East, South-West, South Central and South-East. Table 1 represents SHPs allocation in Bulgaria by REP. Almost 64 per cent of the SHP installed capacity is concentrated in the western region of the country (North-West and South-West REP). The South Central region also represents about 23 per cent of the installed capacity of the country.

In 2014, 7,252 GWh of electricity from RES were generated and more than 60 per cent came from hydropower plants (Figure 4).

FIGURE 4

Structure of electricity generation from RES in 2014



Source: Sustainable Energy Development Agency[7]

More than a quarter of the total amount of electricity produced by the hydropower sector in 2014 (4,543 GWh) was contributed by SHP plants (Table 2).[7] However, there are no special supporting mechanisms for SHP project financing.

TABLE 2

Hydropower capacity and generation in Bulgaria

Power plant type	Number of power plants	Installed capacity (2014) MW	Electricity generation (2014) MWh
Total hydropower (including SHP)	248	2,345.8	4,543,234
SHP	221	290.7	1,142,427
SHP/total hydro (%)	89.11%	12.39%	25.15%

Source: Sustainable Energy Development Agency[7]

Renewable energy policy

The Energy Strategy 2020 of the Republic of Bulgaria is the fundamental document regarding national energy policy. The Strategy sets a special focus on clean and low-emission energy from RES. According to the Strategy, the efforts of the Government will also be directed towards the best possible utilization of the hydropower potential of the country.

Bulgarian renewable energy policy is based on the Energy from Renewable Sources Act of 2011 (ERSA), which transposes Directive 2009/28/EC on the promotion of the use of energy from renewable sources. According to the ERSA, the Council of Ministers determines the state policies for promoting production and consumption of electricity, heating and cooling from RES, the production and consumption of gas from RES, and the production and consumption of biofuels and energy from RES in transport, and the Minister of Energy (former Minister of Economy and Energy) takes charge of implementing them.

The main instrument to achieve the mandatory national target of 16 per cent total share of energy from RES in the gross final energy consumption by 2020, is the National Renewable Energy Action Plan, developed by the Minister of Energy. The National Renewable Energy Action Plan covers the period of 2010 to 2020. Among the main aims of the ERSA are:

- Promotion of production and consumption of energy produced from RES.
- Achievement of sustainable and competitive energy policies and economic growth through innovation, and implementation of new products and technologies.
- Sustainable development at regional and local levels.
- Increasing the competitiveness of small- and medium-size enterprises by production and consumption of electricity, heating and cooling from RES.
- Security of energy deliveries.
- Environmental protection.

According to the ERSA, the EWRC annually approves the estimated electricity capacities for a one-year period. These capacities can be connected to the electricity transmission and distribution grid to projects for production of electricity from RES by region of connection and voltage level. The ERSA also stipulates a series of incentives to encourage production of electricity from RES, such as:

(a) Guaranteed access of electricity from RES to the transmission and distribution electricity grids.
(b) Guaranteed transmission and distribution of electricity from RES.
(c) Ensuring the construction of the necessary infrastructure and electricity capacities for the purposes of regulation of the electricity system.
(d) Priority in the dispatching of electricity from RES.
(e) Purchasing of electricity from RES for a period of:
    (i) Twenty years for power plants, based on solar and geothermal energy, and biomass.
    (ii) Twelve years for wind power plants.
    (iii) Fifteen years for SHP plants (up to 10 MW installed capacity) and other RES.
(f) Feed-in tariffs (FITs) for electricity produced from RES, with the exception of energy produced by hydropower plants with overall installed capacity over 10 MW.

The preferential tariffs in Bulgaria (FITs) were introduced by the Renewable and Alternative Energy Sources and Biofuels Act in 2007. These FITs are determined on 30 June each year, or even more than once per year if there is a significant change of the pricing elements. They do not change during the entire period of the power purchase agreement.

There are a number of financial tools in Bulgaria to support green power projects, namely funds, credit lines and programmes. One exceptional example is the Rural

Regions Development Programme, which is active in providing support in the building of small solar power plants and SHP plants. More than 200 small renewable power plants were put into operation during the period 2010-2014 with the financial support of the programme, including four SHP plants with a total installed capacity of 1.8 MW.

As a result of the renewable energy policy, in 2012, both production and consumption of energy from RES rose substantially. Bulgaria achieved its target of 16 per cent RES share in gross final energy consumption.[8]

Legislation on small hydropower

As per the Water Act (State Gazette No. 67/27.07.1999) which was amended in 2015 (SG No. 17/6.03.2015), all hydropower concessions will be granted under the provisions set forth in the Concessions Act. The Council of Ministers will determine fees for water use permits. Water use rights can be enjoyed only after receiving a permit issued by the Ministry of Environment and Water, which takes into consideration, particularly for dams, the annual flow regime schedule and monthly flow regime schedules. An environmental impact assessment (EIA) may be required prior to the issuance of the permit, as determined by the Environmental Protection Act.[11]

Barriers to small hydropower development

Administrative procedures to get a hydropower plant operating are still one of the highest barriers for the sector. Long periods required for obtaining permissions and licences discourage investors from bringing projects to an end. The duration of the authorization procedures ranges between 36 and 60 months.[9]

Sixty per cent of the rivers in Bulgaria is situated in Natura 2000 areas (protected natural sites).[9] SHP plants in these areas undergo tough environmental impact assessments.

4.1.3 Czechia

Petr Mastny , Jiri Pitron and Jan Moravek, Brno University of Technology

Key facts

Population	10,538,275[1]
Area	78,864 km[2]
Climate	Czechia is a landlocked country located in moderate geographical latitudes in the Northern Hemisphere. The climate is mild but variable throughout the year and it differs among the various regions of Czechia, depending on the height above sea level. The coldest month is January, when the average temperature in the lowlands falls below 0°C. At altitudes higher above sea level, snow coverage usually lasts for several months while in lowlands it remains only for several days. The average temperature during the summer months is approximately 20°C. In the October the average daily temperature usually falls below 10°C. The first light frosts can also occur at this time.[2]
Topography	There are two main regions: Bohemia and Moravia. Bohemia, in the west, is made up of rolling plains, hills and plateaus surrounded by low mountains (highest point: Mount Sněžka at 1,603 m). Moravia (it takes its name from the Morava River, which rises in the north-west of the region) occupies most of the eastern part of the country, including the South Moravian Region and the Zlín Region, parts of the Moravian-Silesian, Olomouc, Pardubice, Vysocina and the South Bohemian regions. Czechia is situated between two mountain systems: the Bohemian range and the Western Carpathians.[3]
Rain pattern	The most precipitation falls in the summer (June and July) and the least in the winter (January and February). In winter, most precipitation occurs mainly in the mountains. The annual rainfall depth varies over time, between 410 mm and 1,700 mm. However, the majority (60 per cent) of years is between 600 and 800 mm.[2]
General dissipation of rivers and other water sources	Most of the territory of Bohemia is drained by the Elbe into the North Sea, a major part of Moravia is drained by the Morava River into the Danube and Black Sea, and the Odra River into the Baltic Sea. Rivers experience the highest discharges in spring as a result of the melting snow.[2,3]

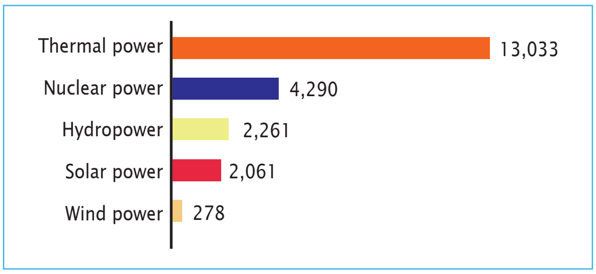
Electricity sector overview

The installed electricity generation capacity in Czechia in 2014 was 21.92 GW (Figure 1) and the electricity production was 79,886.1 GWh (Figure 2) with one third of it coming from nuclear sources.[5] The electrification rate is 100 per cent. Currently, the main renewable energy source for electricity production is hydropower from large dam hydropower stations (approximately 3.66 per cent). As of 2015, the total installed capacity for hydropower was 1,086.6 MW (2,258.1 MW including pumped storage), while generation was 2,707.7 GWh (including pumped storage).[5]

Electricity grids are divided into transmission system and distribution systems. A transmission system is a mutually

FIGURE 1

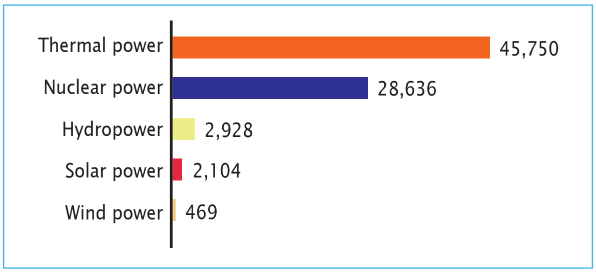
Installed electricity capacity in Czechia by source (MW)



Source: EnergoStat (2014)[4]

FIGURE 2

Electricity generation in Czechia by source (GWh)



Source: EnergoStat (2014)[4]

interconnected system of 400 kV and 220 kV lines and equipment and selected 110 kV lines and equipment serving for the transmission of electricity throughout Czechia and interconnected with the power systems of neighbouring countries and including protection, measurement, monitoring, safety, information and telecommunications systems (CEPS).[12,13]

A distribution system is a mutually connected set of lines and equipment with voltage levels of 0.4 to 110 kV (with the exception of selected 110 kV lines which are part of the transmission system), providing the distribution of electricity in a specified area of Czechia. Transmission and distribution systems are organized and operated in the public interest, which is in line with the Energy Act.

The transmission system in Czechia is operated by CEPS, a public company founded in 1998 by the separation of the Transmission System Department from CEZ (and merging with the dissolving company ENIT). CEPS holds an exclusive licence for electricity transmission. Since 29 September 2009, the Ministry of Industry and Trade has been the major shareholder of the company with an 85 per cent stake. The holder of the remaining 15 per cent stake is the Ministry of Labour and Social Affairs.

The transmission system with voltage levels of 400 kV and 220 kV owned by CEPS serves the transmission of electricity for Czechia as well as for the European electricity market. Czechia is, by means of cross-border lines, connected to the systems of all neighbouring countries, thereby cooperating with the whole electric power system of continental Europe in a synchronized manner.

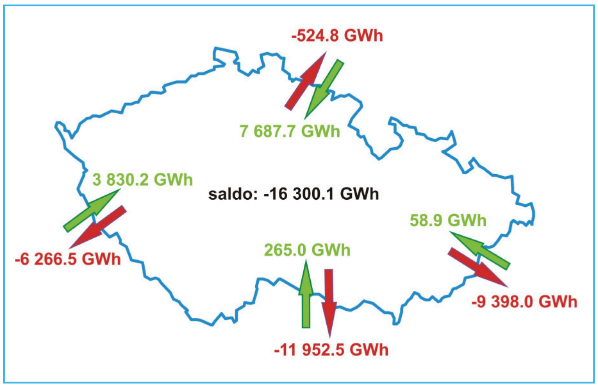
The CEPS transmission system is a set of 38 distribution devices with voltage levels of 420kV and 245kV placed inside 30 substations, also encompassing 2,979 km of 400-kV lines and 1,371 km of 220-kV lines. Furthermore, another 123 kV distribution point and 56 km of 110-kV lines are a component of the transmission system. The import/export of electricity on the transmission network level was 11,187/27,807 GWh and the import/export of electricity on the distribution network level was 654.5/334.8 GWh (Figure 3).[5]

The final price of electricity supplies for the eligible customers on the liberalized market is first composed of a regulated price for those activities that have a natural monopolistic character (i.e. transmission of electricity to a producer via transmission and distribution systems to an end user). This regulation is performed by the Energy Regulatory Office, which on a regular basis issues a Price Decision. The second substantial component of the final electricity price is the price of electrical energy itself which is set by suppliers (producers and traders) along single customer categories and is a contractual matter. This part of the price is not regulated by the Energy Regulatory Office. The final price of electricity supplies for all categories of end users is composed of five basic elements:

- The unregulated price of the commodity, i.e. electrical energy, the price of which is set in line with market principles and in accordance with the trading strategies of single electricity suppliers.
- Transmission of electricity from the producing facility via transmission and distribution systems to an end user.
- Activities tied to ensuring a stable energy system (the provision of system services).
- Business terms (mainly the activity of an electricity market operator in the field of imbalances accounting).
- A contribution to the promotion of electricity from renewable energy, combined generation of electricity and heat and secondary sources.[12]

In this manner, the price of electricity supply is being set for all customer categories since 1 January 2006.

FIGURE 3
Annual power net balance of Czechia



Source: Energy Regulatory Office[5]

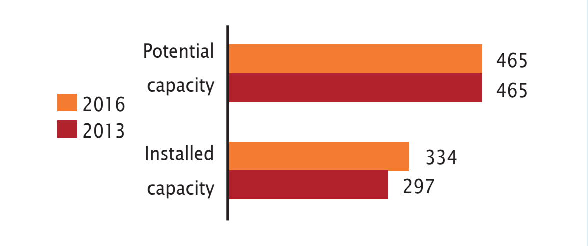
The present situation forces CEPS to invest substantial financial assets for maintenance and support of a stable grid. Czechia should invest, by 2018, CZK 24 billion (approximately US$1 billion) for the development of its transmission system, and, by 2016, CZK 2 billion (approximately US$83.5 million) per year for the restoration of the existing components. CEZ Distribuce, by 2020, intends to invest CZK 130 billion (approximately US$5.4 billion) in the distribution system. The need to react to changes in the production electricity base (increased penetration of Renewable Energy Sources) and associated expenses is also complicated by complex permit procedures for line constructions, which in Czechia last between 7 and 11 years.[12,13]

Small hydropower sector overview and potential

Czechia's definition of small hydropower (SHP) is for installed capacities up to 10 MW. Installed capacity of SHP in Czechia is 333.8 MW while the potential is estimated to be 465 MW indicating that almost 89 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016,* installed capacity has increased by 12 per cent while the estimated potential has not changed (Figure 4).

FIGURE 4

SHP capacities 2013-2016 in Czechia (MW)



Sources: Energy Regulatory Office,[5] *WSHPDR 2013*[14]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Hydropower plants are the country's main renewable energy source. However, rivers and streams in Czechia have low slopes or insufficient flow rates, which is why the hydropower share in overall power generation is relatively low (approximately 4 per cent). It is through the utilization of an additional source of electricity generation that quickly ramps overall power generation up to full output. All large hydropower plants are located on the Vltava River, where they form a cascade-like system called the Vltava River Cascade. SHP plants are mainly located on smaller rivers like the Morava, Sázava, Ohre, Svratka, Dyje, Berounka. The total installed capacity of hydropower plants in Czechia is approximately 2,258 MW, while SHP installed capacity is 333.8 MW, which is 14 per cent of the total (Table 1).[5]

TABLE 1

Hydropower installed capacity and electricity generation in 2015

	Installed capacity (MW)	Electricity generation (GWh)
SHP installed < 1 MW	153.2	527.8
SHP installed 1-10 MW	180.6	538.5
HPP installed > 10 MW	752.8	428.8
Pumped storage plant	1,171.5	1,212.6
Total	**2,258.1**	**2,707.7**

Source: Energy Regulatory Office[5]

The National Renewable Energy Action Plan (NREAP) for Czechia foresees the fulfilment of a 13.5 per cent share of energy from renewable sources (including 10.8 per cent share of energy from renewable sources in transport) in gross final energy consumption in 2020 (Table 2). The main objective of the energy sector is to satisfy long-term energy needs of Czechia. Key priorities of the current National Energy Conception are safety, independence and sustainable development. It envisages a safe supply of energy for reasonable prices, which shall be primarily guaranteed by the use of all available domestic energy sources, as well as the best available global technologies in the most environmentally friendly way. Renewable sources represent a part of these domestic sources and are likely to gradually develop, while fully respecting the size, climatic conditions and parameters of energy grids in Czechia. This includes a gradual reduction of support in line with the technological development and fulfilment of the planned target values of NREAP. Specifically, it also includes the construction of SHP plants with a capacity totalling 15 MW by 2020.[7]

The State Energy Concept provides support for the construction of further SHP plants, in particular through favourable feed-in tariffs (FITs), which guarantee a positive return on investment. Investment subsidies serve as another effective stimulus. The number of sites available for the construction of small hydro plants is limited as licensing procedures are fairly complex and often somewhat protracted.

Renewable energy policy

As a European Union (EU) member, Czechia has a target to reach: 13.5 per cent renewable energy sources (RES) of final energy consumption by 2020 (support new installations of photovoltaic, wind power, small hydroelectric plants and biomass sources), according to the NREAP.

Legislation on small hydropower

Czechia has introduced special renewable energy tariffs or Green Bonus Schemes (GBS) that are calculated based on the time period after plant commissioning. The producers of green energy may choose either the green bonuses, or guaranteed purchase prices. The green bonus

TABLE 2

The National Action Plan for hydropower till 2020 of Czechia

Year	2016 (MW)	2017 (MW)	2018 (MW)	2019 (MW)	2020 (MW)
< 1 MW	152	152	152	153	153
1-10 MW	183	183	191	191	191
> 10 MW	753	753	753	753	753
Total	**1,088**	**1,088**	**1,096**	**1,097**	**1,097**

Source: MPO – The national action plan of Czechia[7] is a bonus to the market price of electricity, which may be provided to a producer of energy from renewable sources (Act No. 180/2005 Coll. on promotion of electricity from renewable energy sources). The producer is entitled to receive the bonus for the electricity sold to any final customer or electricity trader. The bonus is received from the operator of the distribution system, which means the producer achieves the market price and the bonus.

If the producer of energy chooses the guaranteed purchase price, the distributor of electricity is obliged to take all the produced electricity. The state guarantees the purchase prices and the Energy Regulatory Office establishes the price for every year (it cannot be reduced by more than 5 per cent). According to the Act on Promotion of Electricity Production from Renewable Energy Sources, these electricity prices should guarantee investment payback within 15 years. Guaranteed purchase prices for SHP are shown in Table 3. The data is shown for SHP built from 1 January 2015 to 31 December 2015.

TABLE 3

Purchase price for SHP in 2015

	Purchase price (EUR/MWh)	Green bonus (EUR/MWh)
SHP	92.55	62.19
Reconstructed SHP	92.55	62.19
SHP in new locations	119.63	89.26

Source: Energy Regulatory Authority[9]

The tariff is announced on an annual basis by the Energy Regulatory Office. SHP plant operators that intend to offer electricity for purchase to the grid should notify the relevant grid operator in advance. Agreement on costs of support for electricity, heat and decentralized electricity generation, including settlement with mandatory purchases for 2014, totalled to CZK 40.9 billion (approximately US$1.7 billion).

Barriers to small hydropower development

One of the main obstacles to SHP in Czechia is the cost of operation and maintenance, which makes it very expensive. Renewable energy is considered as a complementary source of energy as the priority is given to the fossil fuels and nuclear energy. However, due to other renewable energy sources that are acclaimed as more environmentally friendly, the future of SHP and its financial support mainly depends on the political parties that will govern during the coming years.[8]

4.1.4 Hungary

Attila Bagi, Department of Analysis and Statistics

Key facts

Population	9,849,000[1]
Area	93,030 km[2]
Climate	The climate is temperate throughout, with cold, cloudy and humid winters and warm summers. Annual average temperature is between 10°C and 11°C, with the warmest months (July and August) averaging 21°C and the coldest months (December and January) at 0°C.[2]
Topography	Hungary has mostly flat to rolling plains, with hills and low mountains on its border with Slovakia. The highest point is Mount Kekes, at 1,014 m, in the Matra Mountains.[3]
Rain pattern	The total mean annual precipitation is approximately 600 mm. July is the wettest month, with an average precipitation of 71 mm, and February is the driest, with 29 mm of rainfall.[2]
General dissipation of rivers and other water sources	Hungary is a mostly flat country, dominated by the Great Hungarian Plain east of the Danube. It has large water resources. The two most important rivers, the Danube (417 km) and the Tisza (596 km), are navigable along their whole Hungarian length. Lake Balaton (594 km[2]) is the largest lake in Central Europe and Lake Héviz (47.5 km[2]) is the largest thermal lake in the world.[3]

Electricity sector overview

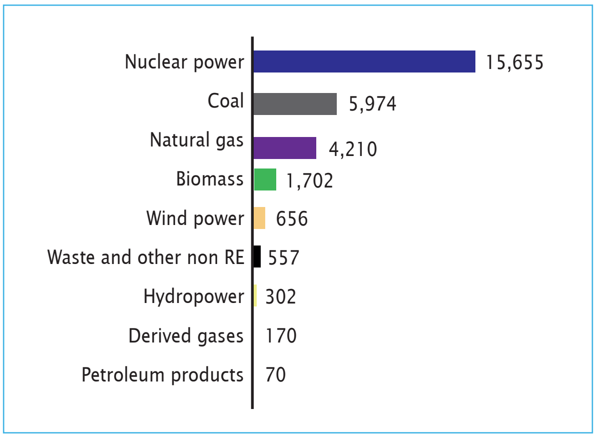
National electricity generation in 2014 amounted to 29.3 TWh, with an installed capacity totalling 8.9 GW (of which 7.3 GW is constantly available). A net 13.4 TWh of electricity was imported. Nuclear energy from the sole state-owned nuclear power plant at Paks accounted for about 53.4 per cent of domestic electricity production. The Paks power plant has four reactors with a total gross capacity of 2,000 MW. A permission procedure has recently been launched to extend the lifetimes of these units. In addition, there are plans to replace old units with new ones. Parallel operation of the old and new units will be temporarily possible.[4]

Gas-fired generation also makes a major contribution to the national electricity supply—it had a share of about 14.4 per cent in 2014. Electricity produced from coal and lignite had a share of 20.4 per cent in domestic electricity production in 2014.[4] Although an open energy market (i.e. power exchange) has already been established in Hungary, electricity trading still takes place in essence in the form of bilateral energy contracts.

Renewable energy has a share of about 10 per cent in electricity generation: biomass and wind being the main pillars followed by hydro and biogas. Solar plays only a subordinate role so far. Hungary aims to increase the share of renewable energy (electricity, heat and transport) from 9.8 per cent (2013) up to 14.65 per cent by 2020. In 2014, gross electricity production was as follows: nuclear (53.43 per cent), coal (20.39 per cent), natural gas (14.37 per cent), biomass (5.81 per cent), wind (2.24 per cent), waste and other non-renewable sources (1.9 per cent), hydro (1.03 per cent), derived gases (0.58 per cent), petroleum products (0.24 per cent).[4]

FIGURE 1

Electricity generation in Hungary by source (GWh)



Source: Hungarian Energy and Public Utility Regulatory Authority (HEA)[4]

Expected growth of electricity consumption is 1-1.5 per cent/year.[5] New power plants are needed mainly to replace the older ones which have to be closed. Hungary is a member state of the European Union so the country had to adopt the EU rules pertaining to the single energy market, which includes ownership unbundling, the creation of a national regulatory sector and of an Agency for the Cooperation of Energy Regulators. Generator plants can be privately owned and producers can sell their electricity directly to customers or on the wholesale market. Despite the monopolistic control of transport infrastructures, domestic regulations ensure non-discriminatory access to the infrastructure in compliance with the EU regulations. The electrification rate in Hungary is 100 per cent.

The majority of the power sector companies are privately owned. There is one large state-owned company in the power sector, MVM who own the Paks nuclear power plant and the transmission network. The State also plans to be directly involved in the supply of universal service costumers (i.e. households and small businesses).

Hungary has an electricity infrastructure strongly connected to neighbouring countries and covers a big part of its electricity needs from imports. The Hungarian Energy and Public Utility Regulatory Authority (HEA) is an independent regulatory body of the energy and utilities industry, and is responsible for the licensing, supervision, and price regulation for electricity, natural gas, district heating and water utility supply, as well as the price preparation of public waste management services. HEA is also responsible for energy statistics.

On a European scale, the domestic residential end user price EUR 0.1202/kWh (approximately US$0.0168/kWh) was one of the lowest in the region in December 2014. Calculated using purchasing power parity however, it was in the mid-range (21.98 (0.01 PPS/kWh)). For industrial consumers, the Hungarian competitive market mean price for electricity is in the EU mid-range.[6] In Hungary, network charges and universal supply (i.e. households and small businesses) end user electricity prices are regulated.

Security of supply is considered satisfactory, but increasing imports causes a challenge regarding the availability of spinning reserves and integrating intermittent renewable sources resulting into a long-term issue. Indeed, Hungary does not have pumped storage plants, and hydropower plants (run-of-river) are strongly subjected to water resources variability.

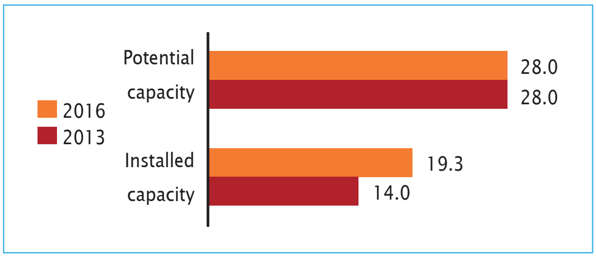
Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Hungary is up to 5 MW. Installed capacity of SHP is 19.3 MW while the potential capacity is estimated to be 28 MW indicating that approximately 69 per cent has been developed.[7] Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 38 per cent while estimated potential has not increased (Figure 2).

The country's hydropower resource potential is mainly located in the catchments of the Danube (66 per cent), the Tisza (10 per cent) and other rivers (24 per cent). Rivers in Hungary exhibit a theoretical power of 990 MW, of which 7,446 GWh/year could be generated. On the small streams, the theoretical production is 308 GWh/year. It is estimated that only 5-6 per cent of the potential hydro energy can be developed. New hydropower projects consist primarily of small plants, with the possibility of re-using water from existing hydropower plants. In 2014, the roughly 20 MW of SHP installed capacity generated 95 GWh and represented approximately 6.3 per cent of total installed hydropower capacity. According to research carried out by the European Small Hydropower Association, the goal for Hungary by 2020 is to achieve an installed capacity of 28 MW, and thus exploit the whole hydropower potential of the country.[7]

FIGURE 2

SHP capacities 2013-2016 in Hungary (MW)



Sources: *WSHPDR 2013*,[10] European Small Hydropower Association [7]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Renewable energy policy

The approved 2009/28/EC Directive on Renewable Energy sets binding targets on the share of renewable energy in gross final energy consumption. The renewable energy target for Hungary is set at 13 per cent by 2020 (according to the EU), but the Hungarian Government is aiming for 14.65 per cent. Biomass and wind are the two main renewable technologies in the electricity sector, with wind scheduled to meet over 3 per cent of total consumption. Hungary has a feed-in tariff (FIT) system to promote renewable electricity production and plans to introduce a premium system from 2016 according to new EU guidelines.[8] No support schemes through green certificate system are planned.

Legislation on small hydropower

Hungary has a sustainable (non-central budget-based) FIT scheme. Tariffs are to be adjusted yearly in line with the inflation rate. There are three types of tariffs for different daytimes: peak, valley and deep-valley period. For plants built after 2008 and hydropower plants over 5 MW, it is indexed with inflation by –1 per cent. The actual tariffs are available on HEA's website.[3] The length of the support period is set by HEA on a project by project basis. For very small (≤ 50 kW) plants, FIT is not available, thus they can only benefit from the net metering.

Barriers to small hydropower development

Hydropower has been a much-debated topic in Hungary for long. The Government still does not consider high-capacity hydropower as a real option compared to other sources of energy. It claims that the topographic conditions of Hungary do not allow for favourable and economic utilization of hydropower. A large part of the country is on flat land, albeit there are some low hills. Rivers with high water output do not have marked drops in elevation. In the Government's view, instead of constructing large dams, it is more feasible to establish small-scale hydropower generators. SHP plants with an output of less than 10 MW and turbines installed in river beds could provide energy-efficient solutions for smaller towns and rural areas.

According to the Government, the establishment of only such smaller plants is of national interest. However, based on Annexes 1 and 2 to the Government Decree No 314/2005 (XII. 25), SHP development on protected natural sites areas is conditional depending on environmental impact assessments and uniform environmental use authorization procedures.[9]

4.1.5 Republic of Moldova

Marcis Galauska, International Center on Small Hydro Power (ICSHP)

Key facts

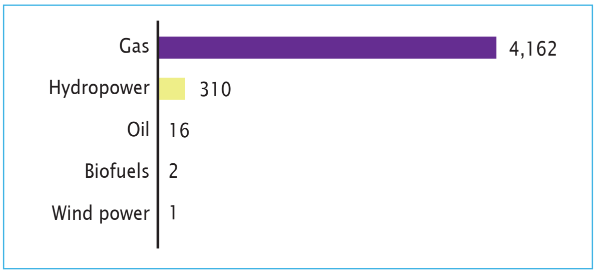
Population	3,546,847[1]
Area	33,851 km²
Climate	The climate is moderately continental with a lengthy frost-free period, short mild winters, lengthy hot summers, modest precipitation, and long dry periods in the south. The average annual temperature increases southward from around 8-9°C in the north to around 10-11°C in the south.[2]
Topography	Hilly plains are found sloping from the north-west to the south-east, with an average elevation of around 147 m above sea level. The Codrii woods in central Moldova are the most elevated topographical region, with a maximum altitude of 429.5 m at Hill Banesti, Nisporeni Raion (district), and have a terrain strongly fragmented by valleys and dales. Erosion, land-sliding and recent upward tectonic movements have led to the formation of hardtops (Romanian: valleys between hills), which represent amphitheatres with open ends facing river valleys. Many rural settlements are located in such landforms.[2]
Rain pattern	The average annual precipitation varies between 600 mm and 650 mm in the north and the centre and between 500 mm and 550 mm in the south and the south-east.[2]
General dissipation of rivers and other water sources	The hydrographic network includes more than 3,000 rivers and streams, of which 10 exceed a length of 100 km. The main rivers are the Nistru (1,352 km, including 657 km within the borders of the country), the Prut (976 km, including 695 km within the borders of the country), the Raut (286 km), the Cogalnic (243 km, including 125 km within the borders of the country), the Bic (155 km) and the Botna (152 km). Moldova has about 60 natural lakes and 3,000 reservoirs. The largest Moldovan lakes are Beleu, Dracele, Rotunda, Fontan, Bic and Rosu, each with a water surface area exceeding 1 km². The largest reservoirs in the country, each with a water capacity exceeding 30 million m³, are those at Costesti-Stanca, Dubasari, Cuciurgan, Taraclia and Ghidighici.[2]

Electricity sector overview

In 2013, overall electricity generation was 4,491 GWh, with an additional 1,456 GWh being imported. Electricity was predominantly generated using gas (4,162 GWh), followed by hydropower (310 GWh), oil (16 GWh), biofuels (2 GWh) and wind (1 GWh) (Figure 1).[2] The total installed capacity is approximately 3,000 MW, most of which is thermal with some 64 MW of hydropower, although only 1,600 MW is available. This includes the 2,520 MW Moldavskaya thermal plant and the 48 MW Dubasari hydropower plant, which are both located in the breakaway state of Transnistria. The Moldavskaya TPP was privatized in 2004 and is managed by the Russian state power group Inter RAO UES, although Moldova does not recognize this privatization.[4] The electrification rate is 100 per cent.

FIGURE 1

Electricity generation in Moldova by source (GWh)



Source: IEA[3]

Moldova is one of the most energy-dependent countries in Europe, importing more than 90 per cent of its oil, gas and coal mainly from Russia and Ukraine.[4] The main goals of the Energy Strategy of the Republic of Moldova until 2030 includes: interconnecting the electricity structure with EU, building new generation capacities and refurbishing the existing ones, reducing electricity consumption, liberalizing the electricity market, as well as lowering dependency on imported resources by developing renewable energy capacity.[5] The average electricity tariff is approximately US$0.11/kWh. Electricity market structure:

- Four generating power plants comprising three CHPs (joint-stock companies, stated-owned) and one HPP (state-owned enterprise) holding licences for generation of electricity;

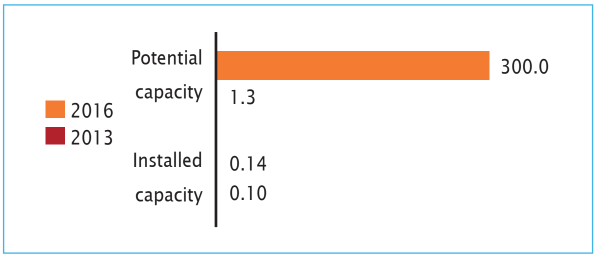
- One state-owned system and transmission operator;
- Three distribution network operators: one privately owned, two state-owned. All operators hold licences for distribution and supply of electricity at regulated tariffs;
- Twelve companies hold licences for supply of electricity at non-regulated tariffs.[7]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Moldova is up to 10 MW. Installed capacity of SHP is 0.14 MW. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016,* installed capacity has increased by 40 per cent while potential capacity increased substantially due to new data reported by UNDP (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Moldova (MW)



Sources: *WSHPDR 2013*,[7] UNDP[10]
Notes:
a. In *WSHPDR 2013*, the potential was derived from planned capacity by 2020.
b. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

There are only two major hydropower plants in Moldova in spite of the large number of rivers. The largest is the Dubasari plant (48 MW) built in 1954 on Dniester, the most important river flowing to Moldova from Ukraine. The second hydropower plant of 16 MW is located in Costesti on the Prut, the second most important river in the country. There are six micro hydropower (< 100 kW) plants, built by individuals or economic agencies and placed on already existing accumulation systems of lakes and drainage. Their total installed power is 141 kW.[8] SHP potential is 1,100 GWh/year.[4] The best areas for SHP development are: the Dniester River basin, the Prut and Danube River basin as they cover the majority of the country's territory.[6] Under the Energy Strategy 2020, mini hydro stations with a capacity of 1.2 MW are planned to be built on the Raut River, close to the village of Tribujeni (Orhei district).[7]

Renewable energy policy

With the adoption of Directive 2009/28/EC, Moldova committed to a binding 17 per cent target of energy from renewable sources in gross final energy consumption in 2020 compared with 11.9 per cent in 2009. The 2030 Energy Strategy of Moldova sets a more ambitious (indicative) objective of reaching a 20 per cent share in 2020.

The National Renewable Action Plan (NREAP) was adopted by the Government in December 2013 and submitted to the Secretariat. According to the document, the 20 per cent target is broken down into an indicative share of 10 per cent in electricity consumption, 27 per cent in heating and cooling and a binding share of 10 per cent in the transport sector. Furthermore, additional electricity generation from renewable energy sources will mainly come from wind power starting in 2016, biogas in 2015, as well as PV. The NREAP also projected a surplus of 3 per cent or 64.8 ktoe that could be transferred to other Contracting Parties or EU Member States, if achieved.

A draft Law on the Promotion of Energy from Renewable Sources has passed the first reading in Parliament in July 2014. It will replace the existing Law on Renewable Energy of 2007. The Law transposes the binding 17 per cent target and the 10 per cent target of renewable energy in transport to be reached in 2020 as well as the other requirements of Directive 2009/28/EC. The Law also envisages the simplification and streamlining of administrative, permitting and licensing procedures.

Moreover, The Law introduces comprehensive support schemes for energy from renewable sources which are based on tendering, a market based mechanism. This is supposed to provide the development of renewable energy at lower cost for customers.

Electricity suppliers will be required to purchase the electricity produced from renewable sources from a single supplier that will purchase the production of all new renewable generators and cogeneration plants. Guaranteed access to the grid and priority dispatch is also provided for in the new Law. Moreover, the Law envisages an energy efficiency fund to support, inter alia, renewable energy projects. Support schemes for renewable energy used for heating are included in a separate Heat Law, which was adopted in May 2014.[5,9]

The legal and regulatory framework for renewable energy has to undergo a major overhaul to reach compliance with the *acquis*, meaning that which has been acquired or obtained. The adoption of the Law on Renewable Energy should be the absolute priority. With its adoption, Moldova will move much closer to implementing Directive 2009/28/EC and will improve the framework needed to attract investment in renewable energy projects and to ensure that the 2020 objectives are met.

The methodology for support schemes for renewable energy projects based on tendering needs to be developed and the administrative procedures including access and connection to the networks need to be simplified after the new Renewable Energy Law is adopted. Later on, monitoring of the effectiveness of the measures by the Ministry of Economy will be very important.

The new Law should also introduce the concept of sustainability criteria and certification of biofuels. After the adoption of the new Renewable Energy Law, the regulatory framework will have to be completed and updated. More generally, the significant agricultural potential of the country should be tapped to develop domestic biofuels production rather than relying on biofuel imports.[5,19]

Barriers to small hydropower development

The main barrier for investments in SHP in the country is capital constraints; there are no national or municipal funds for improving energy efficiency or developing renewable energy projects. High interest rates of bank loans further prevent formation of a market for private companies involved in development of energy projects.[8] So far, implementation of all renewable energy projects has been carried out by state institutions. The lack of public tendering processes has also hindered the formation of a competitive environment for private companies.

4.1.6 Poland

Ewa Malicka, Polish Association for Small Hydropower Development

Key facts

Population	38,478,602[1]
Area	312,679.67 km^2
Climate	A border between zones of moderate and subarctic climates, and between coastal 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, and the warmest month is July, with average temperatures between 16.5°C to 18.5°C. The number of days with temperatures below 0°C ranges between 90 and 130, though it is more than 200 days in the mountains. The number of days with temperatures above 25°C range between 5 and 40.[2]
Topography	Poland is a lowland country with the majority of its land located at lower than 300 m above sea level. The highest point is Rysy, at 2,499 m above sea level, and the lowest point, situated near Raczki Elblaskie village, is 1.8 m below 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 is in its northern border and the ridges of the Carpathian Mountains and the Sudetes constitute its southern border.[2]
Rain pattern	The amount of precipitation depends on the region. The highest is 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, the majority occurring in June and August.[2]
General dissipation of rivers and other water sources	About 99.7 per cent of Poland belongs to the Baltic Sea drainage basin, which in turn is 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 on the east of the Vistula and Oder Rivers, mainly because its topography slopes towards the north-west. The longest rivers are the Vistula (1,047 km), the Oder (854 km), the Warta, (808 km) and the Bug (772 km). Poland has approximately 9,300 lakes larger than 0.01 km^2,[2] which altogether cover 3,200 km^2 (approximately 1 per cent of the country) and have a capacity of 17.4 km^2.[2]

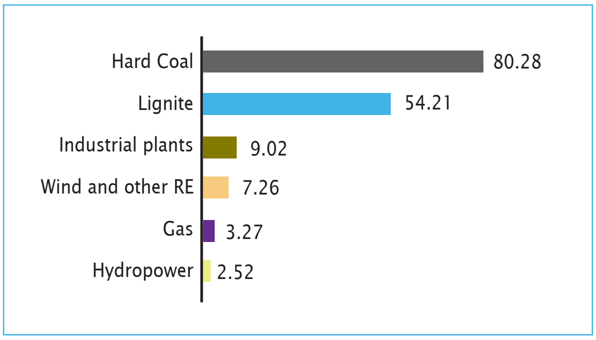
Electricity sector overview

In 2014 installed capacity in Poland was 38,121 GW.[3] Total gross electricity generation was 156,567 GWh and gross electricity consumption was 158,734 GWh.[3] The level of consumption has not changed significantly in comparison to 2013 (an increase of 0.5 per cent) despite the increasing rate of GDP growth in 2014 (estimated at 3.3 per cent). The difference between the generation and consumption volumes (2,167 GWh) was balanced by imports.[3]

Electricity generation in Poland is dominated by hard coal and lignite which contributed 86 per cent of total gross electricity generation in 2014 (Figure 1).[4] Renewable energy accounted for 6,029 GW, or approximately 16 per cent, of the total installed capacity (Figure 2).[6,7] In 2013, renewable energy sources accounted for 10.73 per cent of gross electricity consumption.[8] The electrification rate and grid availability in Poland is 100 per cent.

FIGURE 1

Electricity generation in Poland by source (TWh)

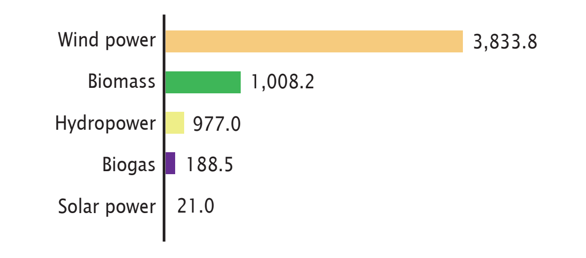


Source: Energy Regulatory Office (URE)[4]

Ever since the energy sector transformations began in 1997, the structure of companies operating in the electricity market has been systematically changing as well. Initial horizontal consolidation of state-owned companies was replaced by changes of a vertical nature. The effect

FIGURE 2

Installed renewable energy capacity in Poland by source (MW)



Sources: Energy Regulatory Office (URE)[3,6]

of the ongoing consolidation of capital groups is a high degree of concentration on the electricity generation and trade markets.[9] In 2014, three companies, Polska Grupa Energetyczna S.A., TAURON Polska Energia S.A. and ENEA S.A., owned more than 50 per cent of installed capacity, and provided nearly 60 per cent of total electricity generation and 57.7 per cent of the energy fed into the grid. In 2014, Polska Grupa Energetyczna S.A. held the largest share of power production (37.9 per cent) and TAURON Polska Energia S.A. held the largest share of retail supply (10.8 per cent).[4] Privatization of the sector was also carried alongside the vertical consolidation process, although most of the Polish power companies continue to be owned by the State Treasury.

Poland has unbundled electric transmission and distribution. The Transmission System Operator, PSE Operator, is the owner and operator of the national transmission grid and is wholly owned by the State Treasury.[10] PSE Operator acts based on its extra high voltage transmission grid, consisting of 242 lines of a total length of 13,396 km, 100 extra high voltage stations as well as a submarine 450 kV DC link between Poland and Sweden (254 km long).[9]

There are five main distribution companies which, while legally unbundled, are, in fact part of large parent companies with significant generation and distribution assets as well as a significant share of the retail market.[11,12]

In the wholesale electricity market, the power exchange and sales to the trading companies constitute the main forms of electricity sales applied by generators. In 2014, sales on the power exchange amounted to 79.3 TWh while sales to the energy trading companies totalled at 53.3 TWh. Trading companies directed their sales mostly towards other trading companies (127.9 TWh), to end users (114.5 TWh) and, to a lesser extent, the power exchange (57.2 TWh).[4]

Pursuant to the Energy Law Act the President of the Energy Regulatory Office calculates and announces the average electricity price on the competitive market for the previous year.[10] In 2014 the average electricity sales price on the competitive market amounted to PLN 163.58 (US$42.57) per MWh, which was 9.9 per cent lower than in 2013.[4]

End users are entitled to receive electricity from a chosen supplier in an uninterrupted and reliable manner.10 There are four tariff groups. 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 total, there are 15 million consumers in the retail electricity market and over 90 per cent are in the G tariff group. Over 14 million households purchase electricity for household consumption. The volume of this purchase is not high and amounts to approximately 24 per cent of the whole volume of electricity supply.10 According to the decision of the Energy Regulatory Office, the prices for companies using tariffs A, B and C are not regulated as of 2008. However, the G tariff (for households) remains regulated.

In the last quarter of 2014 the medium price of electricity in the retail market was PLN 448.1 (US$116.62) per MWh, of which PLN 258.4 (US$67.25) constituted the price of energy and PLN 189.7 (US$49.37) constituted the distribution fee.[4]

According to the 1997 Energy Law, the Polish Energy Regulatory Office, which is an independent agency, is responsible for the regulation of the electricity, gas, and heating markets including licensing, approving investment plans by regulated companies, deregulation of electricity and gas markets, oversight the quality of supply and customer service and setting tariffs.[12]

Polish energy policy focuses on a secure, affordable, and diversified energy supply, with plans for the exploration of domestic shale gas resources and the construction of the country's first nuclear power plant. In the near future the Polish energy sector will require substantial investments, as confirmed by the average age of existing power plants. Almost 40 per cent of power blocks are over 40 years old and 15 per cent of them are over 50 years old.[9] Currently, plants with a capacity of 26 GW are being planned or built mainly using coal, gas and nuclear power.[13] The main goals of the official energy-specific long-term strategy, the Energy Policy of Poland until 2030, are: security of energy supply, climate change mitigation and low energy prices using all available sources including coal, lignite, natural gas, oil, nuclear power and renewable energy.[14] The document does not set priorities and specifications for the desired energy mix through 2030.[6]

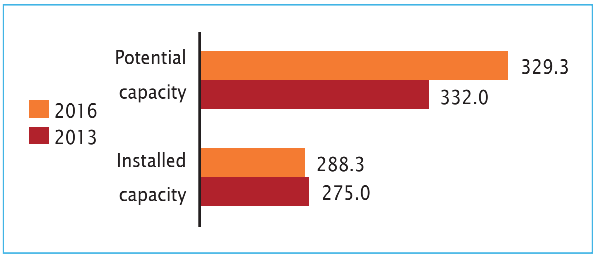
Small hydropower sector overview and potential

There is no official definition of small hydropower (SHP) plants in Poland. However, customarily installations with a total capacity of no more than 5 MW are included in this category.[15] This differentiation is also reflected in the newly adopted Act on Renewable Energy Sources where hydropower plants with a capacity up to 5 MW are subjected to different requirements than larger installations.[16]

In 2014, total installed capacity of SHP was 288.27 MW for plants up to 10 MW and 240.85 MW for plants with a capacity up to 5 MW.[6] Total potential capacity expected to be developed by 2020 is estimated to be at least 329.28 MW for plants up to 10 MW. This would suggest that 87.5 per cent of the 2020 forecast has been developed. In addition to that, the technically feasible potential, which could be developed over a longer perspective, is likely to be much higher (see below).[19] Compared with the *World Small Hydropower Development Report* (*WSHPDR*) *2013,* installed capacity has increased by almost 5 per cent, while potential capacity decreased slightly. The former estimate for potential was based upon a target of 332 MW by 2020, while the current estimate is based upon the combined capacity of sites pending approval (Figure 3).[38]

FIGURE 3

SHP capacities 2013-2016 in Poland (MW)



Sources: Energy Regulatory Office (URE),[6] *WSHPDR 2013*[8]
Notes:
a. *WSHPDR 2016* potential figures are based on the potential capacity expected to be developed; economically feasible potential reported to be 735 MW.[19]
b. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

In 2014, approximately 80 SHP projects (up to 10 MW), with a total capacity of 27 MW and expected annual generation of 120 GWh, were in the process of obtaining permits. It is estimated that these projects could be finalized by 2020. Additionally, there were several projects under construction in 2014 with a combined total capacity of 14 MW and an expected average annual generation of approximately 69 GWh. Thus, an additional 41 MW installed capacity and 189 GWh of generation are expected by 2020.[39]

In 2014, Poland had 756 hydropower plants, 746 up to 10 MW and 740 were up to 5 MW.[6] In 2014, total installed capacity of hydropower plants in Poland was 977.01 MW, indicating that SHP plants up to 10 MW and 5 MW represented 29.5 per cent and 24.6 per cent of total hydropower capacity respectively.7 The number of SHP plants with capacity less than 10 MW has decreased from 761 in 2012 to 746 in 2014.[20,6] As of 30 March 2015 this will decrease further to 743.21 In 2014, normalized electricity generation from SHP (up to 10 MW) was 1,030 GWh.[22]

Nonetheless, potential installed capacity is likely to be much higher even though accurate data for this estimate does not currently exist. The total theoretical hydropower potential of Poland has been estimated to be 23.6 TWh/year with a technical potential of 12 TWh/year.[17] These estimates, though being the only available ones, were carried out between 1953 and 1961 and reflect the state of technology of the 1950s. Experts from the hydropower sector claim that the technical potential should be enlarged by approximately 1.7 TWh to reflect the potential of small water courses characterized by a low head where very SHP plants can be installed.[18] Thus, the technical hydropower potential for SHP plants (up to 10 MW) in Poland is estimated to be approximately 5 TWh/year of which approximately 50 per cent is economically feasible. This would indicate that just 20 per cent of the county's technical potential has been developed so far.[15,19] Other data from the HYDI (Hydro Data Initiative) database indicates that the economically feasible potential is 735 MW.[19]

Hydropower potential in Poland is characterized by uneven distribution throughout the country with 68 per cent of resources concentrated in the Vistula River basin out of which half are allocated in the lower Vistula region. The Oder River basin contains 17.6 per cent of the hydropower potential, while 2.1 per cent is concentrated in the rivers of Przymorze as well as Warmia and Mazury regions, which are not connected with Vistula River Basin. Another 12.5 per cent of hydropower potential is concentrated in the remaining rivers in Poland. The rivers with the largest hydropower potential are the Vistula, Dunajec, San, Bug, Oder, Bóbr and Warta. Regions most favourable for hydropower development are southern parts of Poland (mountain area) as well as western and northern parts (due to existing hydro infrastructures).[17]

In the 1920s and 1930s, there were over 8,000 hydropower facilities in Poland (many types of mills and some hydroelectric power plants).[23] In 1953, there were still 7,230 installations, but only 2,131 remained by 1980s and only 300 were in use at that time.[18,25] The possibility of repowering these historic sites is indicated as the potential for economically feasible and environmentally sustainable small and micro hydropower generation both by the Government and non-governmental organizations (NGOs). In the Energy Policy Of Poland Until 2030 as well as in the Addendum To The National Action Plan For Energy From Renewable Sources, utilization of existing state-owned damming structures for electricity generation is listed as one of the aims.[14,25] Specific actions to be implemented include the "evaluation of plausibility of using the existing damming structures owned by the State Treasury to generate power by way of taking their inventory, establishing their framework environmental impact, and devising the rules of making them available."[14] In order to implement these measures, the National Water Management Authority (KZGW) took an inventory of the damming structures.[26]

The results showed that there are more than 14,000 dams and weirs (with minimum head of 0.7 m) out of which only 4.5 per cent is used for electricity generation. The other two actions stipulated in the Energy Policy have not been taken so far.

Regulations enabling investors to utilize state-owned weirs are included in the new draft Water Law. However, many in the SHP sector find the regulations ineffective as proposed.[27,28] At the same time, similar objectives to develop micro-hydropower potential, by identifying and restoring suitable historical sites, were at the core of the European project RESTOR Hydro. This lasted from June 2012 to June 2015 and was co-funded by the Intelligent Energy Europe Programme of the European Union, with Poland as one of the project implementation countries.[29] Within the project, the RESTOR Hydro Map has been created indicating 50,000 SHP sites in Europe with 6,000 located in Poland. Within the framework of the RESTOR Hydro project, three pilot sites have been selected in each target country (including Poland) and the refurbishment procedures begun.

European funds played a significant role in SHP development in Poland between 2007 and 2013.[30] The financial perspective for 2014-2020 opens new financial potential. Projects related to development, reconstruction and modernization of renewable energy sources are planned for every operational programme. However, some restrictions included in the documents may prevent SHP projects from receiving financing. For example, the requirement that co-financed projects have to be listed in documents resulting from the Water Framework Directive implementation in Poland.[31] Operational programmes are mostly dedicated to local government units and entrepreneurs. Other funding options come from the National Fund for Environmental Protection and Water Management (NFOS) and the Regional Funds for Environmental Protection and Water Management. These funds provide financial support for projects concerned with protection of water and water management, energy efficiency and renewable energy. The financing is carried out by a number of mechanisms such as investment grants, interest-based loans including loans granted by banks, payments for loan interest, loan extinction, etc.[30] Currently, the most interesting mechanism for SHP is a priority programme called Bocian that is dedicated to distributed renewable energy sources. This is planned for 2014-2022 and aims to provide up to 50 per cent of the initial cost, to projects with a maximum cost of PLN 25 million (US$6.5 million) per 1 MW and is available for SHP projects up to 5 MW. Financing for SHP projects in Poland can be also obtained from Norway grants (within the Green Industry Innovation Programme for Poland), the Rural Development Foundation and commercial banks.

It is worth noting that since mid-2012 the Polish renewable energy market began to have difficulties related to green certificates oversupply with prices falling to 40 per cent of their long-term average price. As a result, commercial entities strengthened their requirements, increased loan rates for new offerings, asked for additional loan collateral, stopped renewable energy financing and examined all projects financing applications.[30]

Due to the destabilization of green certificates and the lack of executive regulations with reference to prices for individual renewable energy technology in the new Act on Renewable Energy Sources (adopted on 20 February 2015), it is very difficult to indicate the SHP payback period in Poland.[16]

More than 80 per cent of technical SHP potential generative capacity in Poland remains unused due to historical circumstances and various administrative barriers but also due to its specific nature. Both the governmental inventory and the RESTOR Hydro project outcomes prove the need for adaptation of existing weirs and for making use of sites characterized by very low heads and small flows. According to the SHP sector this goal can only be achieved with stable financial conditions and effective regulations giving investors access to SHP sites.

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 development do not play a significant role for decision-makers. At the European Union level, Poland opposes more ambitious greenhouse gas reduction targets and further developments of climate change policies.[5]

The main energy policy objective in the field of renewable energy sources, and the country's binding target from the EU 2020 Climate and Energy Package, is to increase the share of renewable energy sources in total energy consumption to at least 15 per cent in 2020, and further increase it in the following years. In the drafted Energy Policy of Poland until 2050, subject to public consultation in 2014, renewable energy targets are not clearly reported. However, the sustainable scenario assumes the increase of renewable energy in the final energy use.[32]

Since 2004 support schemes for renewable energy have been based on a quota system whereby relevant entities must have in their purchase portfolio appropriate quantities and types of certificates of origin, with potential non-compliance punishable with the state sanction of monetary fines.[33] Renewable energy producers are supported in two ways: first, they have the possibility of obtaining tradable certificates of origin, green certificates; second, there is an obligation of purchase for electricity by the appointed energy entities, with a price announced annually by the Energy Regulatory Office and based on the free market price from the previous year. This kind of support has been available at the same level for all types of renewable sources generating electricity. Since mid-2012, the system has been destabilized mainly due to the oversupply of certificates causing the value of green certificates to decrease from PLN 251.21 (US$65.55) in 2012 to PLN 184.28 (US$48.09) in 2014 and "black energy" to decrease from PLN 198.90 (US$51.90) to PLN 181.55 (US$47.37).[5,34]

In 2013, an amendment to the Energy Law introduced new regulations enabling prosumers (producers who are also consumers), to run renewable energy micro-installations (up to 40 kW) by simplifying procedures and giving them guaranteed prices (80 per cent of the price announced annually by the Energy Regulatory Office based on the free market price from the previous year).[35]

On 20 February 2015, the Act on Renewable Energy Sources was adopted in Poland introducing a support scheme based on tendering.[16] In the new scheme, reference (maximum) prices will be defined for each technology and additionally within technology for installations with capacity up to 1 MW and above. Auctions will be conducted separately for old and new installations with the capacity division up to 1 MW and above. The producers who win the tender will have the right to receive the offered price for 15 years. The operators of existing renewable energy facilities (except for plants using biomass with capacity over 50 MW, plants co-firing biomass with other fuels and hydropower plants over 5 MW) will be able to choose between support in the form of green certificates or through the new tendering scheme. The new law also introduces feed-in tariffs (FITs) for new installations up to 3 kW and 10 kW (in case of hydropower PLN 0.75 (US$0.195) per kWh for plants up to 3 kW and PLN 0.65 (US$0.169) per kWh for plants up to 10 kW). These new rules will come into full force on 1 January 2016.

Legislation on small hydropower

Other important legal acts, newly introduced, drafted or updated, which regulate and may have an impact on the SHP sector are the Water Law, Water Basin Management Plans (WBMP) and Conditions of Water Use in Water Regions. The draft of the new Water Law, apart from reforming water administration and management, introduces fees for water use in the hydropower sector and rules enabling investors to utilize state-owned weirs through tenders.[27] Updated WBMPs (currently under public consultations and planned to be adopted in December 2015) and established Conditions of Water Use in Water Regions (local legal acts in each water region, either already adopted in 2014 or planned to be adopted in 2015) introduce requirements for residual flow (concluding the method of calculating residual flow is adjusted to the type of watercourse in each water region), fish migration (demands on equipping weirs with fish passes and hydropower plants with barriers protecting fish or fish friendly turbines) and restrictions in developing new hydropower projects (new project development has to be consistent with the EU Water Framework Directive).

Continuously changing legal conditions make a challenge both for SHP investors and operators. The reduction of prices of green certificates has been very perceptible for renewable energy producers. The process of adoption of the new Act on Renewable Energy Sources was turbulent but it is imperative to note that its entry closes a period of uncertainty for the sector. The FITs for micro-installations may, in the case of hydropower, help re-power sites identified in the state inventory and the RESTOR Hydro project.

Barriers to small hydropower development

The support mechanism introduced by the Act on Renewable Energy Sources is not expected to stimulate too many new investments in the hydropower sector. Objections from the sector towards the new law include:

(a) Lack of stability (no guarantee of support and its unknown level at the permitting and prearrangement stage);
(b) The penalty fee paid by producers if the energy generation differs from their declaration;
(c) Classification of producers into only two groups, up to 1 MW and above 1 MW, which creates the risk of eliminating the smallest producers from the system;
(d) Impossibility of regaining support after refurbishment due to the potential accumulation of State aid;
(e) Immediate liquidation of support for hydropower plants with a total capacity of more than 5 MW;
(i) Use of the installed capacity criterion in granting support instead of power generation capacity criterion which discriminates hydropower plants with reservoirs designed for providing services for the energy system.[36,37]
(f) The tendering system does not give the SHP sector a chance to develop new investments. Furthermore there is a risk of a reduction of existing plants due to:
    (i) Destabilization of the green certificates system resulting in reduction of income for renewable energy producers;
    (ii) Increase of operational cost of SHP due to the obligation to adapt the facilities to more and more rigorous environmental requirements (building fish passes and fish barriers, increasing residual flow, etc.);
    (iii) Planned introduction of water pricing for hydropower and expected increase of fees already paid for using state-owned damming structures and lands covered with water.

According to the Act on Renewable Energy Sources SHP plants built before 2005 (approximately 350 out of 740 installations) will be deprived of any kind of support (approximately 50 per cent reduction of income and no purchase obligation). The analyses show that having very little profitability already and with the above mentioned barriers, such a reduction of income may bankrupt cause many producers.[38]

Other barriers to SHP development in Poland include:

- Lack of regulations allowing utilization of over 14,000 state-owned weirs
- Constraints preventing financing of SHP projects from European funds;
- Lack of spatial development plans in which SHP projects would be included (updating the spatial plan may take over two years).

4.1.7 Romania

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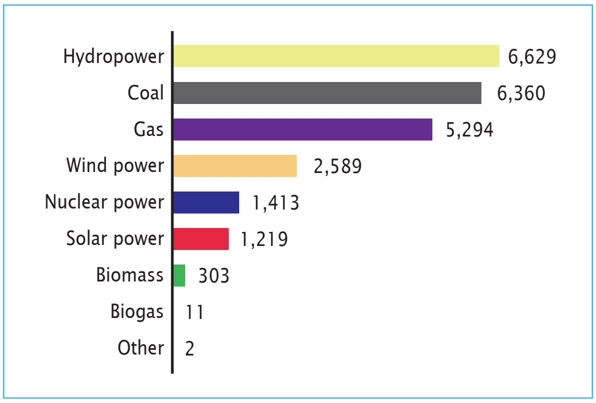
Key facts

Population	19,942,642[1]
Area	238,391 km[2]
Climate	The climate is continental, temperate of transition and specific for Central Europe with four seasons. The winters are cold and cloudy with frequent snow and fog; the summers are sunny with frequent showers and thunderstorms. The average annual temperature is 10°C. Maximum average temperatures in the summer range from 22°C to 24°C and between –3°C and –5°C in the winter.[2]
Topography	The land is almost evenly divided among mountains (31 per cent), hills (33 per cent) and plains (36 per cent). These varied relief forms spread rather symmetrically from the Carpathian Mountains, which reach elevations of more than 2,400 m, to the Danube Delta, which is just a few m above sea level.[3]
Rain pattern	Rainfall, although adequate throughout the country, decreases from west to east and from the mountains to the plains. Some mountainous areas receive more than 1,010 mm of precipitation each year. Annual precipitation averages about 635 mm in central Transylvania, 521 mm in Iasi in Moldavia, and only 381 mm in Constanta on the Black Sea.[3]
General dissipation of rivers and other water sources	The most important river in Romania is the Danube. Its lower course forms a delta that covers much of north-eastern Dobruja. Most of the major rivers are part of the Danube system. These include the Mures, the Somes, the Olt, the Prut and the Siret. Romania has many small, freshwater mountain lakes but the largest lakes are saline lagoons on the coast of the Black Sea, the largest of which is Lake Razelm.[3]

Electricity sector overview

The installed electricity generation capacity in Romania for 2014 was 24.49 GW while the available capacity was approximately 23.82 GW, mainly due to the aging equipment. The available capacity by source in 2014 is provided in Figure 1.[4]

FIGURE 1
Available electricity capacity in Romania by source (MW)



Source: National Energy Regulatory Agency[4]

In 2014, total net electricity generation was estimated to be 59.65 TWh with an increase of approximately 9 per cent from 2013. Electricity generation by source is as follows: hydropower (31.71 per cent), coal (26.44 per cent), nuclear (18.23 per cent), gas (11.64 per cent), wind (9.76 per cent), solar (1.57 per cent), biomass (0.65 per cent).[4]

The National Grid is developing and was challenged by the fast development of wind energy and photovoltaic energy concentrated in the south-eastern and eastern areas of the country, especially wind energy in the Dobrogea region. Therefore, in that area the grid access is completely denied for any additional power plants. Of course, for small hydroelectric power plants, it is difficult to have the necessary transmission capacity in all the mountainous areas.

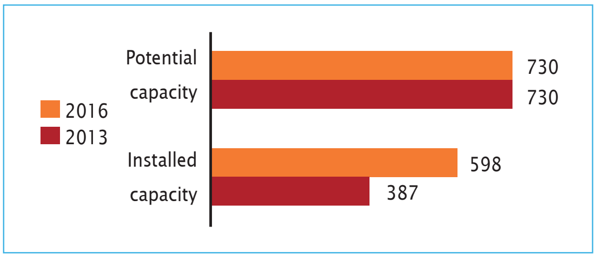
The distribution activity is organized in several zones which were subjected to privatization: Banat (Enel), Transilvania Nord (Electrica), Transilvania Sud (Electrica), Oltenia (CEZ), Muntenia Sud (Enel), Muntenia Nord (Electrica), Moldova (E.On) and Dobrogea (Enel). The Government regulates transmission and distribution tariffs for every region.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Romania is up to 10 MW. Installed capacity of SHP is 598 MW while the potential capacity is estimated to be 730 MW indicating that roughly 80 per cent has been already developed. Between the data reported in the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by 55 per cent and potential capacity has not changed (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Romania (MW)

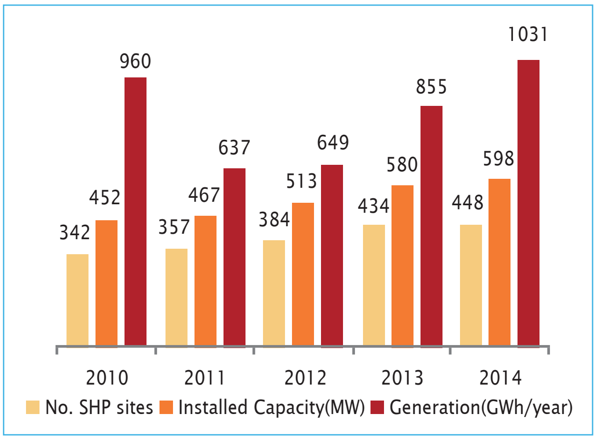


Sources: *WSHPDR 2013*,[8] ESHA [9]
Notes:
a. Data varies per source for SHP installed capacity.
b. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Pumped storage hydroelectric power plants are not considered renewable energy sources and are not included in the Renewable Energy promotion scheme with green certificates. The number of SHP plants has grown steadily in recent years; from 2010 to 2014, the number of sites increased from 342 to 448, with installed capacity rising by 32 per cent over the same period (Figure 3).

FIGURE 3

SHP development 2010 to 2014 in Romania



Source: ESHA[9]

In 2014, hydropower accounted for about 31.71 per cent of total energy generation in the national grid. Romania has already developed approximately 55 per cent from the economically viable hydropower potential mostly in large hydropower plant cascades. From the total installed capacity in hydropower plants of 6,628.70 MW, almost 617.44 MW are reported to have a signed Grid Connection Contract and will be available after commissioning by the owners. From this capacity approximately 323.1 MW are in operation while the net capacity recorded by the National Dispatch Centre is close to 300 MW.

The biggest hydropower potential is concentrated in mountain areas, and especially within the Carpathian Mountains Arch in the Transylvania region. Most important hydrographic basins which are suitable for the small hydroelectric power plant development belong to the following rivers: Mures, Arges, Buzau, Jiu, Crisurile, Nera, and Siret.

In 2014, there was an increase of 9 per cent in the generated energy in the national grid which was justified by the increase of export activities and increase of the internal consumption. It was in part due to an increase in the hydropower generation of 27 per cent (compared to 2013), that the country reached a hydroelectric generation of 18.45 TWh. Nuclear energy was maintained at the same level of approximately 10.67 per cent, while coal energy had an increase of 6 per cent. The energy generated from wind power plants had an increase of 20 per cent and from photovoltaic power plants had an increase of 102 per cent which leads to an important decrease of energy generated from gas (11 per cent) and oil fuel (95 per cent).

Renewable energy policy

The Romanian Government issued GD 57/2013 in 2013, which establish the modifications to the Renewable Energy Promotion scheme defined by the Law 220/2008. According to the GD, in order to protect the end users from high prices of energy and incentives granted to Renewable Energy producers, a number of green certificates were delayed from trading in the period of 2013-2017 (2013-2018 for wind). This decision and the limitation of the ratio of renewable energy from the overall consumption to approximately 11.1 per cent for 2014 and as well for 2015, lead to a diminished interest for the investors in renewable energy regardless of the source.

Most of the important investors have decided to drop all projects until a certainty in legislation will occur.

Because of the legal modifications which affected the number of green certificates and the limitation in annual quota of 11.1 per cent instead of 16 per cent, a large number of green certificates are no longer being traded and the renewable energy producers are not able to transform this form of incentives into cash-flow. The producers remain with untraded green certificates, leading to a drop of price to the minimum value granted by the current legislation of EUR 30 (US$33), instead of the higher value of EUR 55 (US$61).

Because of this, it has been difficult to attract financial support for green energy projects. No bank nor financial institution is giving project financing anymore for renewable energy projects.

However, the introduction of the feed-in tariff (FIT) was announced and approved by the Government and EU Commission as new promotion scheme for renewable energy sources. The National Energy Regulator Agency and Energy Ministry will be in charge of the establishment of the FIT values per each technology and source. Although the FIT will clarify some doubts and assure for the investors a foreseeable cash flow, it will be applied for capacities up to 500 kW.

The current promotion scheme is established by the law 220 from 2008. In the beginning, the promotion scheme was one Green Certificate (GC) for each MWh from all renewable energy sources including hydropower (up to 10 MW), wind, solar, biomass, biogas and geothermal, for a 15 years period. In 2010 the promotion scheme was changed, making Romania one of the most attractive countries for renewable energy sources, granting different numbers for green certificates for each renewable energy source as follows: three GC for SHP and two GC for refurbished ones for 10 year periods, two GC for wind for the first 5 years and then one GC for the following 10 years, six GC for photovoltaic projects and four GC for biomass and biogas.

In 2013 with the new Government, the law 220/2008 was modified with GD 994/2013 and a number of GC were delayed for the operational projects as follows: one GC for wind, one GC for hydro, two GC for photovoltaic until 2017 and 2018 (wind only). This decision was taken in order to reduce the impact to the end user bill of the incentives granted to the renewable energy. Furthermore, the Government issued GD 495 in 2014, which established a State aid scheme which has an exemption from the renewable energy incentives of the large consumers (up to 85 per cent).

Barriers to small hydropower development

Romania is rich in renewable energy resources especially wind (grid connection request for 20 GW), photovoltaic and hydro, but only a small fraction of this potential is used.

The key issues hampering the development of SHP in Romania are as follows:

- A very complex procedure in order to obtain the Water Management Approval and securing a location for the SHP plant development. In order to obtain the water use approval, the investor has first to rent the necessary surface of the minor river bed after a public tender and then apply for the water permit.
- The prices requested for each m^2 rented in the river bed for water intake and other works are limited only at the lowest value making the final price the one of the investor who is offering the highest price.
- The water cost for power generation was increased in 2010 by five times from RON 0.24 (EUR 0.053) to RON 1.1 (EUR0.24) per 1,000 m^3. This affects the cash flow and feasibility of the projects especially for low-head small hydroelectric power plants. For example, for a 5-metre head project, the water costs will reach up to 76 per cent of the energy income (without green certificates incentives).
- Because of the increase in the development of SHP in the last few years in the upper sector of the mountain areas, a large number of environmental activists have emerged asking for the termination of works and stopping this kind of investment. One of the biggest campaigns was done by the World Wide Fund for Nature, a powerful Environmental protection NGO that has a programme of protecting the hydrographic basin of the Danube River and therefore protecting every tributary and affluent within this catchment area basin.

4.1.8 Russian Federation

Galina Livingstone, Livingstone Environmental Ltd

Key facts

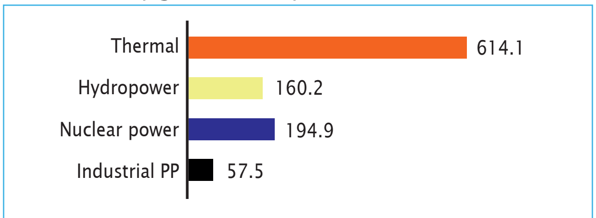
Population	146,267,288[1]
Area	17,125,200,000 km²
Climate	As the largest country in the world, its climate varies considerably. The country has a humid continental climate in much of its European Plain in the western part of Russia, subarctic in Siberia region to the centre-north, and a tundra climate 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 -25°C, varying from 0°C in the North Caucasus to -50°C in the Republic of Yakutia. The average temperature in July is 15°C, but it can be as low as 1°C in the northern coastal areas of Siberia and reaching 25°C in the Caspian region.[2,3,4]
Topography	Broad plain with low hills are found west of the Urals, with vast coniferous forest and tundra in Siberia, and uplands and mountains along the southern border regions. The lowest point is the Caspian Sea (28 m below sea level) and the highest point is Elbrus Mountain (5,633 m, the highest point in Europe).[3]
Rain pattern	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 571 mm. It is highest in July (61.6 mm) and lowest in February (16.7 mm). Most precipitation falls in the north-west, with amounts decreasing from north-west to south-east across European Russia.[4,5,6]
General dissipation of rivers and other water sources	Russia possesses about 20 per cent of the world's freshwater resources, but this water is rather unevenly distributed within the territory. About 90 per cent of the Russian rivers' flow volume 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 is concentrated, have only 10 per cent of freshwater resources.[7]

Electricity sector overview

The Russian Federation (Russia) is one of the top producers and consumers of electric power in the world.[8] Russia's Energy Strategy for the period up to 2035 assumes further increases of electric power consumption particularly in the regions with accelerating economic development such as Russian Far East, Siberia, Russian North and Caspian.[9] Russia has rich gas, oil and coal reserves; therefore, electricity is mostly generated by thermal power plants (including those fuelled by oil, gas and coal, geothermal and solar power plants), but nuclear and hydropower are also providing a significant contribution (Figure 1).

FIGURE 1

Electricity generation by source in Russia (TWh)



Source: UES System Operator,[10] Ministry of Energy (2015)[67]

The UES Group of Russia provides most of the country's electricity and exports power to neighbouring countries over the network of the United Energy System of Russia (UES). UES is the largest centrally controlled electric power system in the world stretching from east to west about 7,000 km and from north to south for over 3,000 km. It comprises about 700 power stations over 5 MW each.

As of December 2014, the total installed capacity of UES power plants was 232,451.81 MW with more than 2.5 million km of electric transmission lines and majority stakes in 69 regional power distribution companies.[10] In 2014 total net electricity generation was 1,057 TWh while the total electricity consumption was 1,038 TWh.[11]

The UES of Russia is working in parallel with the UES of Kazakhstan, Ukraine, Belarus, Estonia, Latvia, Lithuania, Georgia, Azerbaijan, etc. based on bilateral agreements (for example, the Agreement on Parallel Work of Electric Energy Systems of the Republic of Kazakhstan and Russia signed on 23 April 2010).[12,13]

Hydropower plants are one of the key UES components providing 20 per cent of the total installed capacity and over 90 per cent of the regulated power capacity reserve. There are 102 hydropower plants currently in Russia with capacity over 100 MW each. The total installed capacity of the UES grid connected hydropower plants in Russia is about 47,855.18 MW, which is the 5th highest in the world.[14] The Federal hydropower generation company, OAO RusHydro, owns the main part of the hydropower plants in Russia with 38.6 GW of installed electricity generation capacity. As of 1 January 2015, the Government of Russia owned approximately 67 per cent of RusHydro's share capital.[11]

The Federal Grid Company of UES is the owner and operator of the Unified National Electricity Grid (UNEG). The two principal types of activity conducted by the Federal Grid Company of UES are:

- Transmission of electrical power over the electrical grids;
- Provision of technological connections for electricity consumers, the power plants of generating companies and the transmission facilities of other owners to the electrical grid.

These activities are both natural monopolies and therefore regulated by the State.

The Company's assets include more than 139,000 km of transmission lines and 924 substations with more than 332 GVA of 35-750 V transformer capacity. The largest shareholder of UNEG, with a 79.6 per cent stake, is Russian Government.[15]

The country's electrification rate is 100 per cent.[16,17] 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.[18] These regions rely on the local power generation facilities and imported fuel for the power plants.[19] Yakutia is a typical example of such a region where a local company OAO SakhaEnergo is supplying electric power to the area (about 2.2 million km^2 occupied by population of 130,000) mostly by means of 117 autonomous diesel plants.[20]

There are occasional problems with access to the power supply in the areas located in the European part of Russia, e.g. Kaliningrad oblast.[21,22] These problems arise either due to an insufficient local power infrastructure or external influences since these regions are still interconnected to the former parts of the Soviet power grid which are currently located abroad.

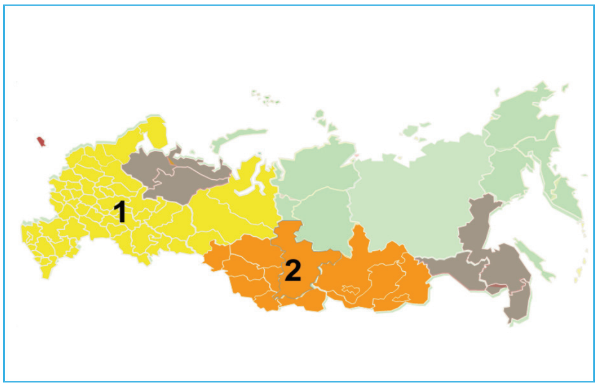
Electricity will be playing an increasing role in the future Russian energy mix. Russian electricity consumption is expected to increase by nearly 2 per cent per year.[23] The main strategic objectives for the Russian electricity industry are modernization of the existing generation capacities and implementation of new generating technologies, including an accelerated development of renewable energy capacities.

The electricity prices in Russia have been gradually liberalized and the majority of wholesale electric power is traded at non-regulated market prices.12 The reform assumes transition to a fully non-regulated electric power market in the future.

The Russian electricity generation market consists of wholesale and retail markets. However, the liberalization of the Russian electricity market currently applies only to the wholesale sector. The public tariffs are likely to remain atate-regulated for the foreseeable future. For the purpose of electricity price control, the whole country is split into pricing zones (1. European Russia-Ural and 2. Siberia), and non-pricing zones (Kaliningrad oblast, Far East, Arkhangelsk Oblast and the Komi Republic) (Figure 2).

FIGURE 2

Russian energy market pricing zones



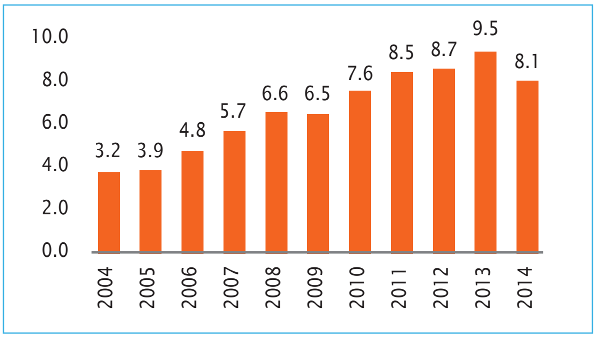
Source: Recent Regulatory and Market Developments for RES-E in Russia [24]
Note: Areas not numbered are the non-pricing electricity market zones

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. For example, as for 26 November 2015, the equilibrium price index in the European Russia-Urals region (Price Zone 1) amounted to RUB 1,179.8/MWh (approximately US$18.0/MWh) while in Siberia (Price Zone 2) it was RUB 940.1/MWh (approximately US$14.4/MWh).[25] The State regulates electricity prices in the non-pricing zones because electricity supply is totally isolated from UES in those areas. The electricity tariff for the end consumer in the retail market steadily increased over the past years (Figure 3).

The responsibility for setting regulated tariffs for electricity and capacity supplied for the residential consumers as well as tariffs for the electricity supply in the non-pricing zones lies with the Federal Anti-Monopoly Service (FAS).[27] FAS is also regulating the tariffs for the renewable energy, e.g. in case of electric power purchased in order to compensate for the grid losses.[28]

FIGURE 3

Average electricity tariff (US$) per 100 kWh for residential consumers in Russia in 2004-2014



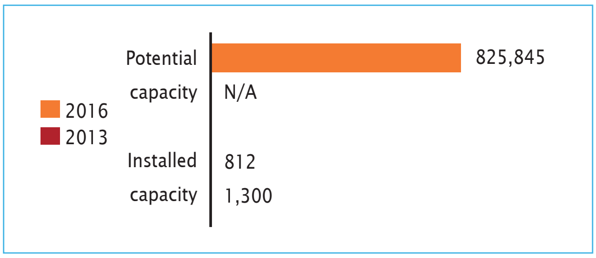
Source: Russian Federation Federal State Statistics Service[26]

Small hydropower sector potential and overview

There is no official small hydropower (SHP) definition currently in Russia. Installed capacity of SHP up to 10 MW is 214.4 MW and up to 30 MW is 811.5 MW while the technically feasible potential for SHP below 30 MW is estimated to be 825,844.6 MW, indicating that only about 0.1 per cent has been developed. The installed capacity has decreased between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016* due to more accurate data becoming available (Figure 4).[29]

FIGURE 4

SHP capacities 2013-2016 in Russia (MW)



Sources: Moscow State University,[29] *WSHPDR 2013*[30]
Note: SHP up to 30 MW
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*

TABLE 1

Overview of SHP plants operating in Russia

Federal District	Estimated potential capacity, MW (SHP < 30 MW)			SHP < 10 MW			SHP < 30 MW		
	Theoretically available	Technically feasible	Economically feasible	Number of SHP plants	Total installed capacity, MW	% Technically feasible capacity	Number of SHP plants	Total installed capacity, MW	% Technically feasible capacity
Central	18,688.9	6,466.7	3,488.9	24	45.8	0.7	26	104.6	1.6
Far Eastern	1,003,777.8	324,000.0	178,000.0	4	5.4	0.0	4	48.6	0.0
North Caucasian	35,111,1	10,666.7	5,555.6	24	55.2	0.5	33	223.7	2.1
North-Western	121,222,2	33,377.8	19,755.6	24	39.5	0.1	33	274.8	0.8
Siberian	966,800,0	301,777.8	166,222.2	6	7.8	0.0	6	7.8	0.0
Southern	100,444,4	30,666.7	17,111.1	7	41.5	0.1	8	63.5	0.2
Ural	300,000,0	93,555.6	51,400.0	5	12.0	0.0	5	12.0	0.0
Volga	77,777,8	25,333.3	14,000.0	16	7.2	0.0	19	76.5	0.3
Total	**2,623,822.2**	**825,844.6**	**455,533.4**	**110.0**	**214.4**	**0.0**	**134.0**	**811.5**	**0.1**

Sources: Various[29,42,43,44,46,47,48,49]

Small rivers are prevalent in the hydrographical network of Russia; the share of small rivers shorter than 100 km in the total length of the hydrographical network is 95 per cent while their total flow constitutes an average of about 50 per cent of the total flow of the Russian rivers.[31] The potential technically feasible capacity of the small rivers in Russia for producing hydropower is estimated at approximately 372 GWh per year.[32]

SHP plants in Russia were initially defined in the Soviet period by regulation SNiP 2.06.01-86, which classified plants with installed capacity up to 30 MW and a turbine wheel up to 3 m as SHP.[33] The latest revision of this regulation, SP 58.13330.2012 introduced on 1 January 2013, does not contain a definition of SHP plant installed capacity. However, the threshold of 30 MW can still be found in the publications about Russian SHP.

The State regulation and strategic planning of the Russian energy industry are primarily concerned with power plants over 25 MW.[34,35] There are special State support measures for electric power plants with installed capacity less than 25 MW that are officially qualified as renewable energy sources.[36] Consequently, the 25 MW threshold is assumed in many publications regarding SHP in Russia.

The current report is considering SHP plants with an installed capacity up to 10 MW, but information about Russian SHP plants with an installed capacity of 25-30 MW is also referenced. The numbers of SHP plants operating in Russia published in Russian sources vary from 60-70 to 200-300, with the higher values found in the earlier reports.[37] In order to clarify this discrepancy, an array of information about SHP plants in Russia was summarized utilizing the datasets from the GIS Renewable Energy Sources of Russia and other publicly available data sources (Table 1).[38,29]

A review of these sources revealed that the number of operating SHP plants of installed capacity below 30 MW each has declined from over three hundred (value quoted in *WSHPDR 2013*) in 2002 to just over a hundred due to the lack of maintenance of many old SHP plants and relatively low numbers of newly built installations.

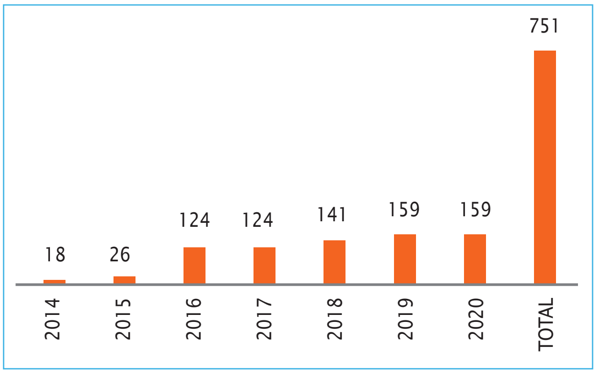
SHP plants have a long history in the country. The first hydropower plant (0.18 MW) was constructed in the Altai region in 1882 for powering water pumps at the Zyryanovsky mine. There is a unique example, an SHP plant named *'Porogy'* (1.45 MW) constructed in the Chelyabinsk region in 1910, which is still operating.[39] 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 when over 6,500 SHP plants were operating in Russia.[40] The State energy policy was changed later in favour of major hydropower plants. Therefore, production of SHP equipment was closed down and the majority of SHP plants were taken out of operation and consequently ruined. Surveys have been carried out proving that restoration of some of these SHP plants can be economically feasible.[41]

The SHP energy sector is reviving in the country. Russia possesses a variety of SHP technologies and produces equipment for SHP plants.[40] The majority of currently operating SHP plants is located in the North Caucasian region and the Republic of Karelia (Table 1).

There are several SHP development plans. The Resolution of the Government of Russia No. 861-r from 28 May 2013 established the following targets for development of SHP installed capacity in 2014-2020 (Figure 5).

FIGURE 5

Russian targets for development of SHP installed capacity in 2014-2020 (MW)



Source: Government of Russia[52]
Note: These targets are for SHP plants with installed capacity < 25 MW.

The plans for SHP plant construction are usually developed at the regional level. For example, the regional authorities of the Adygeya Republic are planning to erect a cascade of SHP plants with a total installed capacity 39 MW.[50] A concept of SHP development was prepared in the Altai region including construction of 35 SHP plants with a total installed capacity of 105 MW (two of these plants are already operating).[51]

RusHydro and NordHydro are the major developers of SHP plants in Russia. RusHydro's development programme includes the construction of SHP plants with a total installed capacity of 850 MW by 2025.[53] NordHydro concluded an agreement in 2015 for an international joint investment project for constructing two SHP plants of below 30 MW each in the Republic of Karelia.[54] The company is currently preparing designs for the reconstruction of 36 SHP plants and construction of 10 new SHP plants in the company property and their strategic plan for the period up to 2025 includes construction of SHP plants in 21 regions of Russia.[55]

There are manifold possibilities to gain financial support for SHP projects. The responsibility for developing SHP in Russia lies with the regional (municipal) authorities and private investors. The regional authorities interested in the development of SHP are capable of financing studies of the hydropower potential in the region, but further implementation usually depends on the private investors. For example, one of the main investors in the SHP projects in Russia, NordHydro, has concluded Agreements for cooperation in development of SHP plants with the regional authorities in five Federal Districts of Russia: North-Eastern, Central, Volga, Ural, and Siberian.[44]

The use of renewable energy sources (including SHP) is considered in the Russia as part of the broader concept of energy efficiency. The main guarantee to the renewable energy investors is provided under the Federal Energy Efficiency Law regarding the determination of the special tariffs for energy efficiency investments including renewable energy projects.[59] Those entities that invested into the 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.

Russia's Law on Electric Power Energy provides a number of mechanisms for supporting the development of renewable energy in Russia.[57] Special State auctions are held each year selecting renewable energy investment projects (wind, solar and SHP). Agreements for the Delivery of Capacity are concluded between renewable energy investors and wholesale market consumers. By signing these Agreements, investors commit to construct a certain type of production installation of a certain capacity, and at a certain location. They also guarantee availability of their installations for electricity production. In return, investors are remunerated at regulated tariffs. The tariffs are estimated according to the 'Rules of tariff estimation for the renewable power generating entities' approved by the Russian Federation Government Decree No. 449 from 28 May 2013. The tariff is established individually for each renewable energy operator following the method set out in the Decree No. 449. The tariff is calculated based on the bid capital costs that investors submitted for participation in the competitive selection of renewable energy projects, and it is applicable for 15 years.[65,66]

SHP plants with an installed capacity of below 25 MW that participate in the retail electric power market can 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 renewable energy sources;
- Establishment of feed-in tariffs (FITs) for renewable energy that account for a certain return on the investment (currently at 14 per cent);
- Obligation of the grid companies to buy renewable energy despite the difference in tariffs (i.e., renewable energy tariffs are now 3.5 times higher than those for conventional energy generators).[58]

Apart from utilizing the investment support mechanisms available in Russia, investors can benefit from international incentives. For example, the mechanism of "joint projects with third countries" allow EU Member States to support the construction of renewable energy installations in non-EU countries.[59] For example, this support mechanism is relevant for the renewable energy projects in the north-west of Russia since they are capable of exporting the electric power to the EU over the existing links with adjacent countries (Finland, Estonia, and Latvia).

Renewable energy policy

The renewable energy policy in Russia is defined in The Energy Strategy for the period up to year 2030 (revised for the period up to 2035 in a draft published in 2015) and The Strategy for Development of Renewable Energy, both adopted in 2009.[9,34,60,61] These documents consider accelerated development of the renewable energy sources as an important factor of the economic modernization of the country.

The share of renewable energy in the total electric power generation is currently less than 1 per cent, but The Strategy for Development of Renewable Energy set the following targets for its increase: 1.5 per cent in 2010; 2.5 per cent in 2015; and 4.5 per cent in 2020. The targets are established for the State, but not for the electric power generating companies. These targets are not legally binding, and there would be no fines for falling behind them (as has already happened).

A legal framework supporting the renewable energy sector has been under development by the Russian Government since 2009. For example, the regulation adopted in 2010 for reimbursement of owners of renewable energy generating facilities for costs related to interconnection to UES.[62]

According to Yegor Grinkevich, the Deputy Director of the Department of Electricity of the Ministry of Energy of Russia, the basic idea of the existing legal framework is that support to the renewable energy projects should be carried out primarily at the regional level, on the basis of strategic documents that should be adopted by regional authorities.[63]

The Energy Strategy of Russia is providing requirements for an advanced development of SHP technologies as well as improvements in the industrial facilities producing equipment for SHP plants.[60] The country will develop the renewable energy sector, taking into account the structure and features of the national energy industry.

An intensive utilization of renewable energy sources in Russia would bring a number of important benefits such as:

- Electric power supply for the isolated consumers, i.e. those who do not have access to the centralized electric power distribution grids;
- Reduction of the liquid fuel supplies to the remote northern areas of Russia including the Arctic region (e.g. replacing local diesel generation with renewable energy sources);
- Increased reliability of the electric power supply in areas with the centralized electric power distribution

grids, particularly those experiencing shortages of the electric power supply;

- Reduction of the air pollution resulting from the thermal power stations fuelled by coal or oil.

Russia joined the International Agency for Renewable Energy (IRENA) on 22 July 2015.[64] This membership allows Russia to participate in the development of international renewable energy standards, and adopt the best practices and advanced technologies.

Barriers to small hydropower development

The main barrier for developing renewable energy projects, including SHP, in Russia is due to the availability of vast fossil fuel resources, as well as the importance of the Russian gas, oil, coal, and nuclear industries for the country's- economy. Other significant barriers in developing SHP projects in Russia are:

- Lack of state-supported programmes for SHP development;
- Lengthy procedures of land allocation and State approvals for the projects that can sometime last for many years;
- Excessive requirements for the projects imposed by the regional grid companies for provision of the grid connection;
- Shortage of up-to-date scientifically proven data on the regional capacity for developing SHP projects;
- Lack of standard technical and methodological regulations, information technologies and software required for designing, constructing and operating renewable energy generation plants;
- Lack of specialist training and skilled professionals at the regional level;
- Insufficient state support in development of the SHP technologies;
- Natural and environmental constraints, e.g. seasonal restrictions (frost, floods), locations in environmentally sensitive areas, etc.

The Federal budget is not providing finance for SHP projects. The Russian banks are reluctant to finance SHP projects due to the long-term period of recoupment for such investments. Consequently, there are many examples in Russia when construction of SHP plants has been put on hold.

4.1.9 Slovakia

Frantisek Janicek, National Centre for Research and Application of Renewable Energy Sources

Key facts

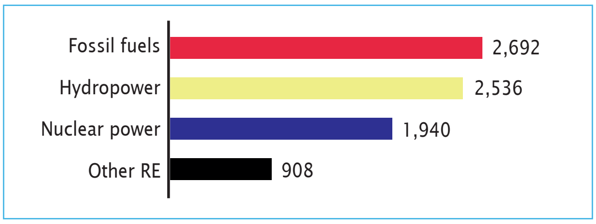
Population	5,415,949[1]
Area	49,035 km^2
Climate	The climate is moderate continental with four distinct seasons. Summers tend to range from hot to temperate, while winters are cold, cloudy and humid. The average daily temperature range is -3°C to 2°C in January and 16°C to 26°C in July. Temperatures are lower in the mountains.[2]
Topography	Mountains are found in the central and northern part of the country, while lowlands are in the south. The highest peak is Gerlachovsky Stit (2,655 m) in the High Tatras mountains along the border with Poland; the lowest point is Bodrok River (94 m) in the south-east. The capital city, Bratislava, is situated in the largest region of plains, where the Danube River forms part of the border with Hungary.[3]
Rain pattern	Precipitation in the form of rain and snow averages 500 mm in the south-west to about 2,000 mm in mountains. In winter, most of the precipitation is in the form of snow and in summer there are often storms with torrential downpours.[2]
General dissipation of rivers and other water sources	Most of the rivers flow south into the Danube, which, together with the Morava, forms the country's south-western border. The main channel of the Danube River demarcates the border between Slovakia and Hungary for about 175 km. As it leaves Bratislava, the Danube divides into two channels. The Danube proper continues southward along the border with Hungary. The smaller channel, the Little Danube, branches eastward and then south-east to meet the Váh River. The Váh continues south and converges with the Nitra and with the main branch of the Danube at Komárno. The Hron and Ipel' Rivers also flow south and enter the Danube. The eastern rivers also tend to flow to the south, eventually entering the Danube. Among them are the Hornád and the Ondava. The Poprad, also in the east, is the only sizable river that flows northward, into Poland.[4]

Electricity sector overview

Slovakia's installed capacity was 8,076 MW in 2014. However, due to some thermal conventional power plants that are in long-term shutdown, the available capacity was approximately 3,500 MW. Approximately 33 per cent of capacity came from fossil fuel-fired power plants (natural gas, lignite, coal, oil, mixed fuels), 31 per cent from hydropower, 24 per cent from nuclear and 11 per cent from other renewable sources, such as photovoltaic, biomass, biofuel and wind (Figure 1).[5]

FIGURE 1

Installed electricity capacity in Slovakia by source (MW)

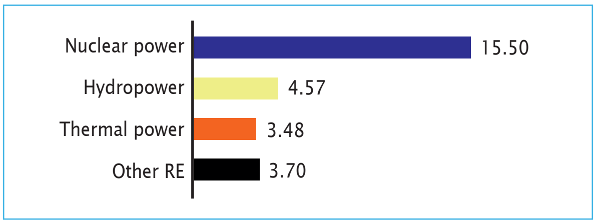


Source: National Grid Control Centre of Slovakia[5]

Distribution of sources is concentrated in the west where both Mochovce and Jaslovské Bohunice nuclear plants are located as well as the Gabcikovo, a large hydropower plant with 720 MW of installed capacity. The next most important region is Povazie on the river Vah where there are many hydropower plants collectively named Vagus's Cascade and a pumping power plant in Cierny Vah with a capacity of 735 MW. Conventional thermal power plants are located in Novaky, near lignite mines, and in Vojany, where hard coal is imported from the east.[7]

FIGURE 2

Electricity generation in Slovakia by source (TWh)



Source: National Grid Control Centre of Slovakia[5]

In 2014 total net electricity generation was 27.25 TWh and consumption was 28.36 TWh. Approximately 57 per cent of net generation came from nuclear power, 17 per cent from hydropower, 13 per cent from thermal power plants and 14 per cent from other renewable energy sources (Figure 2).[5] Slovakia has 100 per cent electrification rate. Slovakia is close to balancing consumption and production of electricity. In 2014 Slovakia was a mild importer of electricity due to the fact that it was more economical to import electricity than to produce it. This was largely a result of the preceding years, which had lower than expected rainfall.[6]

While real GDP is growing (2.4 per cent in 2014), consumption of electrical energy is stagnating.[1] Between 2001 and 2011, total energy consumption decreased by 12 per cent. This was due to a greater efficiency of electrical products, the use of modern production technologies and the economization caused by the deregulation of energy prices.[6] The Ministry of Economy is expecting slow growth in electricity consumption and the country is finishing two new blocks of the Mochovce nuclear plant. Once operational, Slovakia is expected to be a net exporter of electricity.[6]

The entire electricity transmission network is owned by the state-owned company Slovenská elektrizacná prenosová sústava, a.s. (SEPS). There are also 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).[5]

Generation and wholesale activities were liberalized in January 2005. The main player in the Slovak electricity generation market is Slovenské elektrárne, a.s. (SE), a joint stock company of which 66 per cent is owned by Enel, the Italian based multinational group, with the other 34 per cent owned by the State.[5] Slovenské elektrárne is the biggest electricity provider in Slovakia with 82 per cent of the country's generation market.[1]

As the Slovak Republic is a member of the European Union (EU), it is obliged to adhere to EU policies. One of the main objectives is the gradual transition to a low carbon economy. By 2020, Slovakia has an obligation to achieve a 14 per cent share of renewable energy in gross final energy consumption. By 2030 this rises to 20 per cent. Slovakia is also a member of the Union for the Coordination of Transmission of Electricity (UCTE).[6] Slovakia is part of the CENTREL area which also includes Poland, Hungary and Czechia.

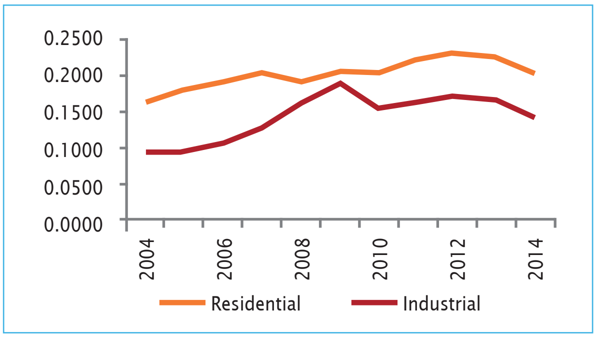
As of the first quarter of 2014, the average electricity price for medium-sized households, including all taxes and levies, was EUR 0.1507 (US$0.2007) per kWh which was slightly below the EU average. The average cost for medium-sized industrial consumers, not including taxes, during the same period was EUR 0.1107 (US$0.1475) per kWh which was slightly higher than the average rate across the EU (Figure 3).[10]

Small hydropower sector overview and potential

Slovakia defines small hydropower (SHP) as plants less than 10 MW installed capacity. Total SHP installed capacity is 81.6 MW with an estimated potential of 241.4 MW indicating that approximately one third of the total potential has been developed. Compared to data from the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, both installed capacity and estimated additional potential capacity has increased (Figure 4).

FIGURE 3

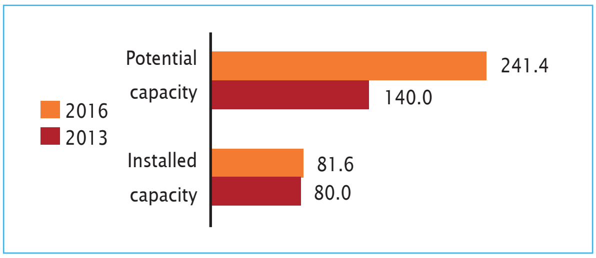
Annual average electricity cost to consumer 2004-2014 (US$/kWh)



Source: Eurostats[10]

FIGURE 4

SHP capacities 2013-2016 in Slovakia (MW)



Sources: Atlas of Renewable Energy Sources,[8] *WSHPDR* 2013[14]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

There are currently 217 SHP plants in operation generating 281.8 GWh (Table 1). This contributes 6 per cent of the total electricity generated from hydropower and 1 per cent of the country's total generation.

TABLE 1

SHP in Slovakia

Power rating	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**	**81.64**	**281.8**

Source: Atlas of Renewable Energy Sources[8]

Hydropower potential of large rivers for large hydropower plants in Slovakia is almost completely developed. However, SHP potential still exists.[7] Based on the gradual transition to a carbon-free economy and on the Plan for Hydroenergy Power Utilization in Slovakia up to 2030 there are plans to build up to 368 SHP plants (Table 2).

TABLE 2

Planned SHP plants

River basin	Number	Installed capacity (MW)	Generation (GWh)
Dunaj	19	10.281	69.286
Vagus	121	64.91	316.857
Hron	129	57.171	272.725
Bodrog and Hornad	99	27.507	138.381
Total	**368**	**159.87**	**797.25**

Source: *Atlas of Renewable Energy Sources*[8]

The total installed capacity of these plants is 160 MW with an annual production of approximately 797 GWh or 3 per cent of total electricity consumption.[10] The total technical potential of rivers is 392,344 MW, with an annual production of 1,713.76 GWh of electricity. Many rivers, however, are located in protected areas preventing construction. Many of the new projects are planned for construction on the River Orava, where a stretch of 24.6 km has a planned production of 107.5 GWh. However, there are efforts to declare this stretch of river as a protected area. The most promising river for the construction of hydropower is considered to be the River Hron. There are 24 proposed hydropower plants, for which 3 already own permits.[9]

Renewable energy policy

The objectives of the Slovak Energy Policy are to ensure an affordable, environmentally sensitive and reliable supply of electricity for all consumers. In line with the EU energy policy, there is a support system for renewable energy systems set in place in order to achieve a target 24 per cent share of total electricity generated and 14 per cent share of total energy consumption (including heat and transport) from renewable energy sources by 2020. Renewable energy sources have priority connection to the electricity system, are eligible for feed-in tariffs (FITs) and can receive investment support during construction.

Legislation on small hydropower

SHP plant owners enjoy additional payment for electricity supplied within the period of 15 years from putting the facility into operation or from the year of reconstruction or upgrade of a technological part of the facility. The energy price resulting from additional payment is calculated as a percentage of the base price announced by the Regulatory Office of Network Industries (URSO). The typical value of the base price is EUR 0.06-0.11/ kWh depending on plant capacity. URSO establishes the price individually for each facility based on the submitted proposal, taking into account various factors, including time passed since the re-commissioning and investment assistance have been granted. The support is granted in full value for power plants with capacity up to 10 MW. In case of higher capacities, the additional payment is granted for electricity production from the 10 MW.

Barriers to small hydropower development

Administrative and environmental barriers are discouraging private investors. Other renewable energy sources, such as biomass, biogas and photovoltaic, have a shorter payback period as compared to SHP plants. Construction of SHP plants in Slovakia is also difficult due to the long bureaucratic process. When private developers identify a suitable location for the plant, the permission procedure to comply with the Slovak Building Act is as follows:

- Compiling zoning planning references and zoning planning documentation;
- Compiling documentation necessary for zoning permits;
- Having building plans compiled as a prerequisite to the building permit.

Investors then require permission according to the Slovak Water Act and approval from various environmental organizations. Some of the required references are: environmental requirements, terms and requirements of the national water management authority, hydrological data, topographic references, geological references, local reference data, and other reference documentation.

The construction of SHP must be organized by an authorized person. The construction project amounts to a comprehensive technical, economic, environmental and architectonic solution. An important part of the project is evaluating its viability in order to determine whether it has a favourable payback time for investors.

Although the building of SHP plants is a very complex matter, it is necessary to obtain extensive experience with its construction. In addition to technical issues, it is very important to be familiar with legislation and local laws. After identifying suitable sites, issues of ownership of the land need to be resolved. Following that is undergoing the process of obtaining a building permit under the Building Code. Moreover, hydropower plants must be in accordance with the Water Act and the Environmental Impact Assessment. On the basis of these laws it is necessary to submit a number of documents addressing all the organizations, which is very challenging. Projects in these structures may be developed only by authorized civil engineers.[8]

Large hydropower potential of rivers in Slovakia is almost fully exploited. However, potential for SHP plants in most of Slovakia remains largely untapped. In regards to the construction of SHP, there is a broad mistrust from the general public and environmental activists. There is little activity amongst investors because of fears of a long return on investment, and of the complex permitting process. Government bodies may show reluctance to develop a large number of SHP plants, because of the difficulties in controlling its output; this is not a difficulty when compared to a smaller number of large hydropower plants.

4.1.10 Ukraine

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Key facts

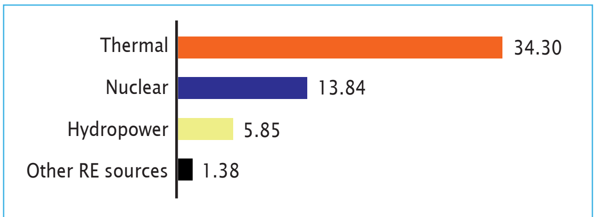
Population	45,426,269[1]
Area	603,550 km[2]
Climate	The climate is mostly temperate continental, with the southern coast being Mediterranean. Winter months, between November and March, are warmer along the Black Sea but colder further inland. Summer months between May and September are warm across the greater part of the country but hotter in the south. The average temperature in January is between –8°C in the north-east and the Carpathian highlands and 4°C in the southernmost parts of the country. In July the temperatures range between 17°C in the north-west, 19°C in the Carpathians and 23°C in the south.[1]
Topography	The majority of Ukraine consists of fertile plains (steppes) and plateaus. Mountains are found only in the west (the Carpathians) and in the Crimean Peninsula in the extreme south. Mount Hoverla, which is part of the Carpathians, is the highest point in Ukraine at 2,061 m.[1]
Rain pattern	Rainfall is disproportionately distributed across the country. The average annual rainfall ranges from 600 mm to 650 mm in the west and north-west to 300 mm in the south and south-east. Maximum rainfall occurs in the Crimean Mountains (1,000-1,200 mm) and the Carpathians (1,500 mm).[2]
General dissipation of rivers and other water sources	There are 63,119 rivers and streams in Ukraine, 93 per cent of which are shorter than 10 km in length. The longest river is the Dnieper (approximately 2,201 km in length), the fourth longest river in Europe. Generally, rivers in Ukraine flow from north to south and drain into the Black Sea.[2]

Electricity sector overview

In 2014 the total installed capacity of power plants in Ukraine was 55.37 GW.[3,6] The majority, approximately 62 per cent, is derived from thermal power while approximately 25 per cent is from nuclear power, 11 per cent from hydropower plants including pumped-storage hydropower and the remainder from other renewable energies (Figure 1 and Table 1).[3,6]

FIGURE 1

Installed electricity capacity in Ukraine by source (GW)



Sources: Ukrenergo,[3] State Agency on Energy Efficiency and Energy Saving of Ukraine[6]

Hydropower plants (over 10 MW) are located on the Dnieper (3,940 MW), the Dniester (744 MW), the Tereblya (27 MW) and the Southern Bug (11 MW). Three pumped-storage hydropower plants have been commissioned: Kiev (235 MW), Dniester (648 MW) and the first stage units of Tashlyk (302 MW) power station. Total capacity of pumped-storage hydropower plants is expected to achieve 4,074 MW.[13] Total annual electricity generation in 2014 was 182.4 TWh. The main producers were nuclear (48 per cent) and thermal (41 per cent) power stations. Hydropower and renewable energy sources generated only 5 per cent and 1 per cent of the total energy respectively (Figure 2).[4]

TABLE 1

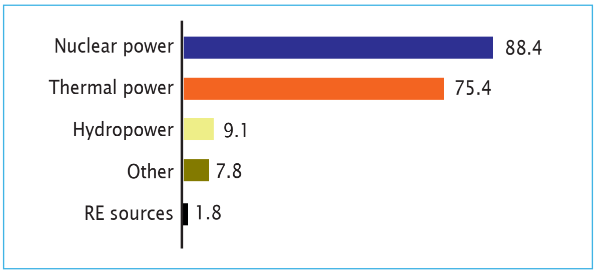
Renewable energy sources in Ukraine (excluding large hydropower)

Renewable energy type	Total number of facilities	Installed capacity (MW)	Electricity generation (TWh)	Electricity generation (%)
Wind energy	21.0	513.9	1,171.5	58.3
Solar power	102.0	824.7	485.2	24.2
Small hydropower	105.0	81.4	250.7	12.5
Biomass	5.0	35.2	60.9	3.0
Biogas	9.0	13.9	39.3	2.0
Total	**242**	**1,462.17**	**2,007.6**	**100**

Source: STAPEEU[6]

FIGURE 2

Annual electricity generation in Ukraine by source (TWh)



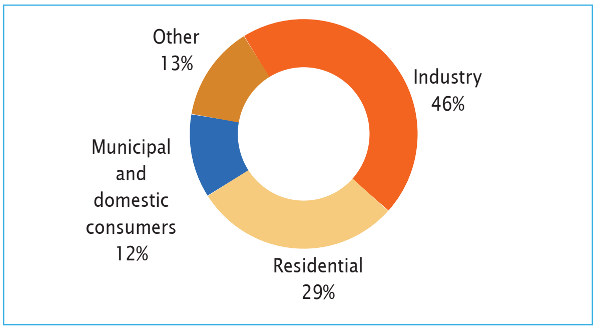
Sources: STAPEEU[4]

Hydropower plants cover peak loads, control frequency and power; and provide mobile emergency reserves of power in the Integrated Power System of Ukraine.[14] The total hydropower potential of Ukraine is over 44 TWh while the cost-effective undeveloped potential is approximately 6.5 TWh.[12,13]

The electrification rate in Ukraine is 100 per cent.[26] The industrial sector is the biggest consumer of electricity with approximately 45 per cent of consumption, more than half of which is consumed by the metallurgy sector (Figure 3).[4,5]

FIGURE 3

Electricity consumption in Ukraine (%)



Sources: STAPEEU,[4] Ministry of Energy and Coal Mining of Ukraine[5]

The Ukrainian energy market consists of:

- State regulators including: the Verkhovna Rada of Ukraine, the Cabinet of Ministers of Ukraine, and the National Commission for State Energy and Public Utilities Regulation. They establish the authority of state agencies, basic rights and obligations of electricity market participants, electricity prices and tariffs.
- Power producers (both state-owned and private).
- Power network operators with operative and technological control of the IPS, electricity transmission, distribution and supply.
- Wholesale electricity market that purchases all the electricity produced at power plants and sells it at wholesale prices.

The Integrated Power System (IPS) of Ukraine is central to the country's electric power industry. The IPS is a technical system consisting of power plants, trunk/main power transmission networks and distribution networks (which are combined by a common mode of electricity generation), transmission and distribution according to the centralized control of the state-owned enterprise National Power Company Ukrenergo (NPC Ukrenergo). There are eight regional power systems: Dniprovska Power System (Dnipro PS), Donbaska PS (Donbass PS), Zakhidna PS (Western PS), Krymska PS (Crimean PS), Pivdenna PS (South PS), Pivdenno-Zakhidna PS (South-West PS), Pivnichna PS (North PS), Tsentralna PS (Central PS). They are connected by high-voltage power lines of 220 kV, 330 kV, 400 kV, 500 kV and 750 kV.

Centralized electricity generation is provided by: the state enterprise National Nuclear Energy Generating Company Energoatom (NNEGC Energoatom) which operates nuclear plants, the state-owned Public Joint-Stock Company Ukrhydroenergo which operates large hydropower and pumped-storage plants, and six private power generation companies (Dniproenergo, Zahidenergo, Shidenergo, Donbassenergo, Centrenergo, Kyivenergo) operating thermal power plants. According to the *Law of Ukraine on Privatization,* nuclear power stations, large hydropower plants, pumped-storage plants and main transmission power networks cannot be privatized. There are 24 private regional power distribution companies that carry electricity to individual consumers.

The state-owned company Ukrenergo provides electricity through its main power transmission networks from power generation companies to power distribution companies.

The state-owned company Energorynok is the only buyer in the wholesale electricity market purchasing electricity from all producers and selling to all suppliers at a single wholesale market price. The wholesale market price is formed monthly by the National Commission for State Energy and Public Utilities Regulation. The level of wholesale market price depends on changes in nuclear fuel, coal, natural gas and oil prices as Ukraine is importing 100 per cent of its nuclear fuel and 75 per cent of its gas.

In May 2015 the cost for 1 kWh of power was set at EUR 0.032 (US$0.024) for thermal power plants and EUR 0.017 (US$0.023) for nuclear power plants.[7,8] Hydropower has a two-part tariff, which consists of payments for electricity and fees for installed capacity. In 2015, the rate of payment for electricity was set at EUR 0.01/kWh (US$0.01) and the rate of payment for installed capacity was set at EUR 0.044/kWh (US$0.059).[9] For producers of electricity from renewable energy sources, there are legally-adopted Green feed-in tariffs (FITs) that will be valid up to 2030.[10] The tariff depends on the type of energy, its capacity and the date the power plant was commissioned. In May 2015, the tariff rate for small hydropower (SHP) stations with capacities between 200 kW and 1,000 kW was equal to EUR 0.16/kWh (US$0.21).[11] During the year, retail electricity tariffs for the population are fixed and identical across all regions.

Small hydropower sector overview and potential

Ukraine defines SHP as less than 10 MW (Table 2).[10] Installed capacity is approximately 81 MW with a total potential capacity estimated at 1,140 MW, thus indicating that only 7.1 per cent has been developed. In the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, potential capacity was unknown. However, between these reports, installed capacity has decreased by approximately 20 per cent (Figure 4).[25] This is largely due to introduction of a green tariff (see below) which reduced the definition of SHP plants from less than 30 MW to less 10 MW.

TABLE 2

Small, mini and micro-hydropower classifications

Type	Classification
Micro hydropower	Less than 200 kW
Mini hydropower	200 kW-1 MW
Small hydropower	1 MW-10 MW

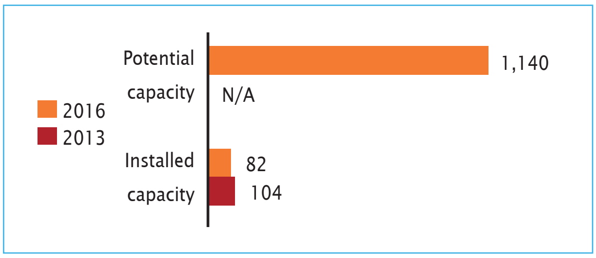
Source: The Verkhovna Rada of Ukraine[10]

The approximate SHP capacity of 81 MW comprises 105 SHP plants with an average annual electricity production of 250 GWh. The majority of stations are situated in the Vinnitsa region where the total capacity is 22.45 MW, followed by the Kirovograd, Ternopil and Transcarpathian regions.[27]

According to the *Energy Strategy of Ukraine for the Period until 2030* SHP potential capacity is estimated at 1,140 MW with an annual electricity production of 3.34 TWh/year.[13] The greatest potential is concentrated in the Zakarpattya, Lviv, Ivano-Frankivsk, Chernivtsi, Zhytomyr and Poltava regions. Currently, there are state administration programmes in the Carpathian region for the construction of SHP plants on the upper section of the Dniester and construction of low-head and high-head derivative power stations on the Upper Tisza and its tributaries. It is possible to construct around 300 SHP plants in the Transcarpathia region, 20 in the Lviv region, and 150 in the Ivano-Frankivsk and Chernivtsi regions.[15] The total investment required to fully develop this SHP potential is estimated at EUR 2 billion (US$2.7 billion).

FIGURE 4

SHP capacities 2013-2016 in Ukraine (MW)



Sources: STAPEEU,[6] Cabinet of Ministers of Ukraine,[13] *WSHPDR 2013*[25]
Notes:
a. SHP definition in Ukraine in 2013 was < 30 MW; in 2016 it is < 10 MW, which accounts for part of the decrease in installed capacity.
b. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Renewable energy policy

The Green Tariff is applied to almost all renewable energy sources (except for electricity produced by large

TABLE 3

Minimum Green tariffs for plants commissioned from 1 January 2015 to 31 December 2019

Type of renewable energy sources	Capacity of power stations and other mitigating factors	Retail price (EUR (US$) per kW)	Green tariff coefficient	Peak factor	Rate tariff (EUR (US$) per kW)
Wind	Up to 600 kW inclusive	0.054 (0.072)	1.08	1	0.058 (0.077)
	More than 600 but not exceeding 2,000 kW	0.054 (0.072)	1.26	1	0.068 (0.090)
	More than 2,000 kW	0.054 (0.072)	1.89	1	0.102 (0.136)
Solar energy	Power on the ground	0.054 (0.072)	3.15	1.8	0.305 (0.407)
	Power on the roofs and / or facades of houses with a capacity exceeding 100 kW	0.054 (0.072)	3.24	1.8	0.314 (0.418)
	Power on the roofs and / or facades of houses with a capacity of up to 100 kW inclusive	0.054 (0.072)	3.33	1.8	0.323 (0.430)
	Power on the roofs and or facades of private households with up to 10 kW inclusive	0.054 (0.072)	3.33	1.8	0.323 (0.430)
Biomass and biogas	Waste	0.054 (0.072)	2.07	1	0.111 (0.148)
Hydropower plants	Micro-hydropower	0.054 (0.072)	1.8	1.8	0.174 (0.232)
	Mini-hydropower	0.054 (0.072)	1.4	1.8	0.140 (0.186)
	Small hydropower	0.054 (0.072)	1.1	1.8	0.105 (0.139)

Source: The Verkhovna Rada of Ukraine[10] hydropower plants). It is set for each company by the National Commission for State Energy and Public Utilities Regulation. The tariff takes into account construction costs, maintenance and rate of return for the electricity producer. Rate tariffs cannot be lower than the guaranteed minimum Green Tariff (Table 3). A fixed minimum size of the Green tariff is set through the conversion of Euros ito the national currency. The rate tariff is formed as the product of the retail electricity tariff as of January 2009, the coefficient tariff for each type of energy source and the coefficient of peak hours. Thus, fixing the size of the Green tariffs converted into Euro as of January 2009 protects investors against possible inflation.[10]

The Green tariff scheme is in place until January 1, 2030. The size of the Green tariff coefficient for electricity generated by power plants which will be commissioned or significantly upgraded after 2014, 2020 and 2024, is set to be reduced by 10 per cent, 20 per cent and 30 per cent respectively (Table 4). The state guarantees the purchase of electricity and its full payment.

For projects using the Green tariff, the law establishes mandatory requirements for the procurement of settings and services of Ukrainian origin. The share of Ukrainian materials, equipment, services and works depends on the date of commissioning the facility and the type of renewable energy source. Ukrainian origin of materials and works is confirmed by certificates provided by the Ukrainian Chamber of Commerce and Industry or regional Chambers of Commerce. This requirement, however, does not apply to micro, mini and small hydropower plants.[10]

Legislation on small hydropower

State incentives for SHP generation include: the privatization of SHP plants, the Green Tariff, tax benefits and preferential access to the electricity network. According to the existing legislation, SHP plants have to be privately owned or leased (large hydropower plants are not subject to privatization).[10,16] There are a number of tax incentives to encourage electricity generation with SHP plants:

- Exemption from income tax for 10 years, beginning from 1 January 2011 (the current tax rate is equal to 21 per cent). The amount of tax-exempted funds may only be used to increase production, upgrading of logistics, introduction of new technologies, repayment of loans and its interest payments
- Exemption from value added tax and customs duties on importing of facilities for the period until 1 January 2021
- Exemption from tax liabilities in the form of special surcharge for electricity production (3 per cent of the electricity produced)
- 75 per cent reduction in land tax for land used for power plants
- Restrictions on the rent for land that is state or municipal property

There are a number of national laws and programmes for the protection, conservation and use of natural resources, as well as international treaties, conventions and protocols. The main regulatory documents include:

TABLE 4

Green tariff coefficients for commissioned facilities 2013-2029

Type of alternative energy sources	Capacity of power stations and other relevant factors	Up to 31 Mar 2013 inclusive	1 Apr 2013 to 31 Dec 2014	1 Jan 2015 to 31 Dec 2019	1 Jan 2020 to 31 Dec 2024	1 Jan 2025 to 31 Dec 2029
Wind	Up to 600 kW inclusive	1.2	1.2	1.08	0.96	0.84
	More than 600 but not exceeding 2,000 kW	1.4	1.4	1.26	1.12	0.98
	More than 2,000 kW	2.1	2.1	1.89	1.68	1.47
Solar energy	Power on the ground	4.8	3.5	3.15	2.8	2.45
	Power on the roofs and / or facades of houses with a capacity exceeding 100 kW	4.6	3.6	3.24	2.88	2.52
	Power on the roofs and / or facades of houses with a capacity of up to 100 kW inclusive	4.4	3.7	3.33	2.96	2.59
	Power on the roofs and or facades of private households with up to 10 kW inclusive	—	3.7	3.33	2.96	2.59
Biomass and biogas	Waste	2.3	2.3	2.07	1.84	1.61
Hydropower plants	Micro-hydropower	1.2	2.0	1.8	1.6	1.4
	Mini-hydropower	1.2	1.6	1.44	1.3	1.1
	Small hydropower	1.2	1.2	1.08	1.0	0.8

Source: The Verkhovna Rada of Ukraine[10]

The Law of Ukraine On Environmental Protection (2012 edition), The Water Code (2014 edition), The Land Code (2014 edition), The Forest Code (2014 edition), Convention on the Conservation of European Wildlife and Natural Habitats (1979, introduced in 1982), The European Landscape Convention (2006), The Framework Convention on the Protection and Sustainable Development of the Carpathians (2003) and The Protocol on Conservation and Sustainable Use of Biological and Landscape Diversity to the Framework Convention. All these documents should be considered in detail when developing the Environmental Impact Assessment (EIA) of a SHP plant project.[17,18,19,20,21,22]

With the development and implementation of programmes for the construction of SHP plants, the environmental provisions of the international document Guiding Principles on Sustainable Hydropower Development should also be considered.[23] This was adopted in June 2013 at a high-level meeting of the International Commission for the Protection of the Danube River.

Barriers to small hydropower development

The current regulatory framework of the country provides good opportunities for the development of SHP even though some Government acts may prolong construction and cost. Green electricity, for example, can be sold to the energy market or directly to end consumers. However, These consumers have no economic and regulatory incentives for the purchase of electricity at the higher rates of green tariffs. In addition to that, though SHP plants are exempt from value added tax and customs duties on the import of equipment, the list of this equipment is set by the Cabinet of Ministers of Ukraine and this privilege is granted only by a special procedure following Government agreement. To do this, it is necessary to receive the correct conclusions from the Ministry keeping in mind how this privilege is granted is not defined thus eliminating transparency.[24] Lastly, the financial system of Ukraine has no loans with low interest rates for SHP development.

4.2 Northern Europe

Egidijus Kasiulis, Aleksandras Stulginskis University

Introduction to the region

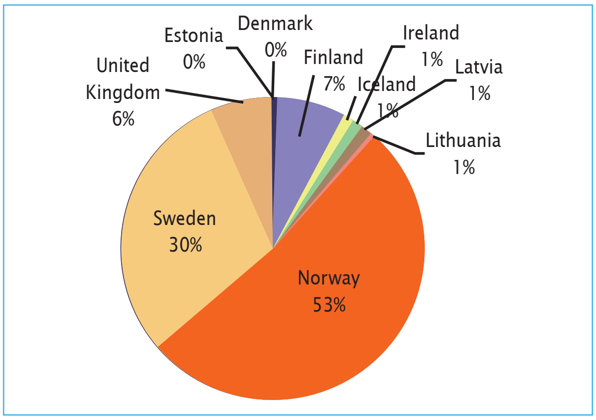
There are 10 countries in the region. As 8 of the 10 countries are in the European Union, renewable energy policy in the region is shaped according to the EU Directives. One of the main EU goals is to constantly increase electricity production from renewable energy sources. Consequently, this means that in all countries the installed hydropower capacity is gradually increasing despite the strict environmental restrictions. Northern Europe is fully electrified.

The temperate climate of Northern Europe is influenced by the presence of the Gulf Stream, the North Sea and the Baltic Sea. The climate is characterized by moderate summers and winters in the southern part of the region and central parts of the region with subarctic climatic zone patterns in the northern part. The precipitation rate is usually sufficient. Northern Europe can be described as a lowland territory with the exception of the mountain ranges in Norway, United Kingdom (Scotland) and Iceland. The region has abundant water resources with numerous rivers and lakes. The longest rivers are the Daugava (Latvia, length 1,020 km, average discharge 678 m³/s), Neman (Lithuania, 914 km, 616 m³/s) and Glomma (Norway, 621 km, 720 m³/s). An overview of the countries in Northern Europe is presented in Table 1.

Norway and Sweden together account for 83 per cent of the regional share of small hydropower (SHP) (Figure 1). Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed SHP capacity has increased by 17.5 per cent from 3,643.3 MW to 4,281.25 MW mainly due to development in Norway and Sweden (Figure 2).

FIGURE 1

Share of regional installed capacity of SHP by country



Source: *WSHPDR 2016*[17]

Small hydropower definition

In all countries with the exception of Ireland, the definition of SHP is up to 10 MW. The definition of SHP in Ireland is up to 5 MW (Table 2). In Sweden, some legislation uses the older categorization of SHP up to 1.5 MW.

TABLE 1

Overview of countries in Northern Europe (+ % change from 2013)

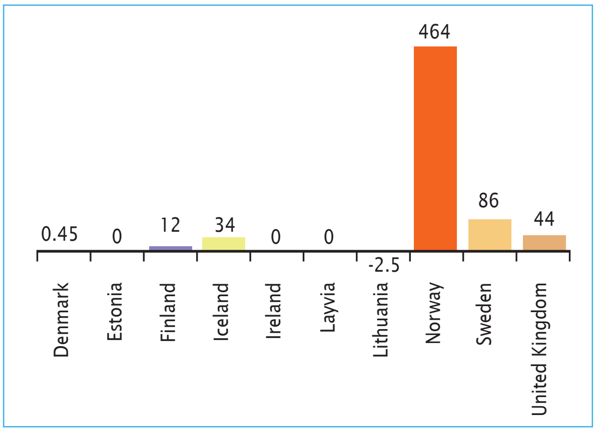
Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Denmark[1,2,3,5]	5.64 (+1.8%)	12 (-1%)	100	13,550 (+9.9%)	34,747 (-11.6%)	9.8 (+5.1%)	21 (0%)
Estonia[1,2,5]	1.32 (+3.2%)	32 (+1%)	100	2,713 (+20.2%)	10,900 (-15.9%)	8.0 (-2.4%)	26 (-15.4%)
Finland[1,2,4]	5.46 (+3.7%)	16 (+1%)	100	16,947 (+3.5%)	65,400 (-27.0%)	3,151 (+1.6%)	12,700 (-0.5%)
Iceland[1,2,4,6]	0.33 (+6.0%)	6 (-1%)	100	2,760 (+7.0%)	18,120 (+6.2%)	1,986 (+5.4%)	12,872 (+4.8%)
Ireland[1,2,7,8]	4.61 (-2.4%)	37 (-1%)	100	7,383 (-19.1%)	24,405 (-10.5%)	229 (-8.0%)	580 (-20.0%)
Latvia[1,2,9]	2.03 (-7.6%)	32 (0%)	100	3,000 (+21.5%)	5,561 (+55.8%)	1,590 (+6.0%)	1,993 (-43.4%)
Lithuania[1,2,10]	2.92 (-17.3%)	34 (+1%)	100	4,304 (+12.9%)	4,398 (-64.2%)	128 (-0.8%)	394 (-1.5%)
Norway[1,2,4,11]	5.17 (+5.7%)	20 (-1%)	100	32,500 (+3.4%)	142,400 (+14.5%)	30,900 (+3.1%)	136,600 (+15.9%)
Sweden[1,2,12,13]	9.75 (+7.1%)	14 (-1%)	100	38,273 (+7.2%)	149,000 (+15.1%)	16,155 (-0.3%)	60,900 (-6.7%)
UK[1,2,4,14]	64.60 (+2.5%)	18 (-2%)	100	85,000 (-5.8%)	336,000 (-2.9%)	1,551 (-5.9%)	5,900 (+3.6%)
Total	**101.83 (+2%)**	—	—	**206,430 (+0.06%)**	**790,931 (-0.5%)**	**55,707.8 (+1.8%)**	**231,986 (+6.1%)**

Sources: Various[1,2,3,4,5,6,7,8,9,10,11,12,13,14,19]

Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for Northern Europe



Sources: *WSHPDR 2013*,[18] *WSHPDR 2016*[17]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.

TABLE 2

Classification of SHP in Northern Europe

Country	Small (MW)	Mini (MW)	Micro (kW)	Pico (kW)
Denmark	Up to 10	—	—	—
Estonia	Up to 10	—	—	—
Finland	Up to 10	0.1-1.0	10-100	> 10
Iceland	Up to 10	0.1-0.3	> 100	—
Ireland	Up to 5	—	> 6	—
Latvia	Up to 10	—	—	—
Lithuania	Up to 10	—	—	—
Norway	Up to 10	0.1-1.0	> 100	—
Sweden	Up to 10	—	—	—
United Kingdom	Up to 10	—	—	—
EC [15]	1-10	0.1-1.0	5-100	> 5

Sources: European Commision,[15] *WSHPDR 2013*,[18] *WSHPDR 2016*[17]

Regional SHP overview and renewable energy policy

In Northern European countries the distribution of installed capacity and potential varies dramatically—from values of over 1,000 MW in Norway and Sweden to under 10 MW in Denmark and Estonia (Table 3).

The goal for the energy sector in Denmark by 2050 is 100 per cent power generation from renewable energy sources. Unfortunately, this comes from a country that is topographically unsuited for hydropower, which is well reflected in the country's hydropower potential. All installed hydropower capacity in Denmark comes from SHP plants and it is noted that no development of SHP is planned.

Estonia is another country in the region in which all hydropower capacity comes only from SHP plants. It is also a country with one of the lowest hydropower potentials in the region. In addition to this fact, a list of 112 rivers and their reaches were recently introduced as protected areas for fish populations, resulting in a reduction of the hydropower potential from 30 MW to 10 MW. Therefore, this indicates that SHP in the future will play a marginal role amongst other renewable energy sources.

Finland could increase its installed SHP capacity by tapping one fifth of all technically feasible hydropower potential on unprotected rivers. Still, the development of SHP in this country in recent years was slowed by low electricity prices as well as long and costly licensing procedures.

Iceland has access to large amounts of renewable energy sources, which means not only does the country have one of the cheapest prices of electricity in Europe, but also having this amount of untapped renewable energy means none of the renewable sources are given priority for grid connection or special subsidies. This makes SHP development questionable, because the priority will be given for medium or large hydropower plants since they could be more profitable.

In Ireland, there are approximately 600 old mill sites that could be restored and up to 10 potential high-head sites suitable for hydropower. Adding these to the sites that are viable commercially or domestically in different counties, the development of all these sites could almost double the installed capacity of hydropower in Ireland. A low level of public awareness concerning development of hydropower is one of the main setbacks.

Taking into account environmental restrictions, it is estimated that in Latvia the untapped SHP potential is up to 300 GWh. Still, the development of SHP in Latvia is limited due to legislative requirements and a negative social stigma for hydropower. The situation is very similar in Lithuania. Although the public opinion concerning SHP in Lithuania is more positive, the development of the hydropower sector is very unlikely due to the exceptionally strict environmental legislation.

About 96 per cent of generated electricity in Norway comes from hydropower and there is still a large interest in developing the remaining substantial potential. New SHP plants in Norway and Sweden are supported by a joint green electricity certificate scheme. However, in Sweden the development of SHP is limited by environmental requirements and increasing capacity is possible mainly through the refurbishment of old power plants.

Recent studies revealed that there is a considerable amount of undeveloped financially feasible SHP sites in the United Kingdom of Great Britain and Northern Ireland. However, the development of SHP is slow due to environmental requirements and low feed-in-tariffs (FITs).

TABLE 3

SHP up to 10 MW in Northern Europe (+ % change from 2013)

Country	Potential (MW)	Planned (MW)	Installed capacity (MW)	Annual generation (GWh)
Denmark	9.75 (+4.8%)	N/A	9.75 (+4.8%)	28 (0%)
Estonia	10.0 (+11.1%)	N/A	8.0 (0%)	26 (-13.3%)
Finland	590 (+ 93.4%)	N/A	314 (+4.0%)	1,992 (+51.6%)
Iceland	N/A	1	69.9 (+179.6%)	N/A
Ireland	60 (0%)	N/A	42 (0%)	160 (0%)
Latvia	75 (+114.3%)	N/A	26 (0%)	68 (-1.5%)
Lithuania	40 (0%)	N/A	26.5 (-8.6%)	100 (+7.5%)
Norway	7,676	1,941	2,242 (+20.7%)	9,100 (+19.7%)
Sweden	1,280 (+4.1%)	N/A	1,280 (+7.2%)	5,041 (+10.3%)
United Kingdom	1,179 (+237%)	N/A	274 (+19.1%)	530 (-33.8%)
Total	**10,919.75 (+184.3%)**	**1,942**	**4,292.15 (+17.8%)**	—

Sources: *WSHPDR 2016*,[17] *WSHPDR 2013*,[18] HYDI[16]

Barriers to small hydropower development

The governments of the Northern European countries have introduced renewable energy policies supporting electricity generation from renewable energy sources, including support mechanisms for SHP and goals to increase the share of renewable energy by 2020. Nevertheless, the development of SHP in the region has been significantly slowed by the environmental requirements and legislation. Another barrier that emerged in recent years and has derailed or postponed a number of SHP projects is the low price or electricity, which has in some cases extended the payback period for SHP and RE investments.

4.2.1 Denmark

Mikael Togeby, Energy Analyses

Key facts

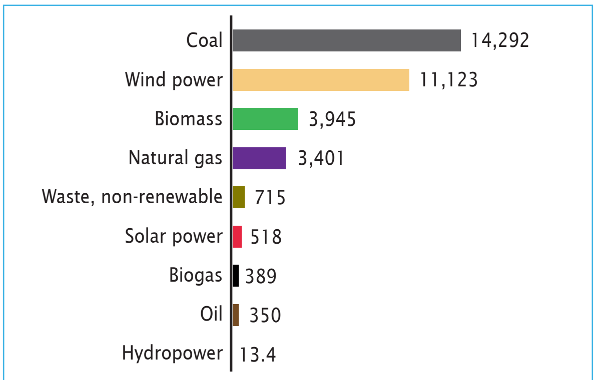
Population	5,639,565[1]
Area	43,094 km^2
Climate	Denmark's climate is temperate, mostly humid and overcast with mild and windy winters and cool summers.[1] The average annual temperature for the entire country is 7.7°C (average of 1961-1990), ranging from 7.4°C in central Jutland to 8.4°C at some coasts. The average land temperature has increased significantly during recent decades. DMI statistics show that average mean temperature since 1990 has been approximately 8.5°C.[2]
Topography	Most of the country is low and flat to gently rolling plains.[1] The highest natural peak (without man-made mounds of earth, etc.) is Møllehøj at 171 m.[4]
Rain pattern	The average annual precipitation over land is 712 mm but varies greatly from year to year and from place to place. On average, it rains most in the central parts of Jutland, with over 900 mm, and least in the Kattegat and Bornholm, with about 500 mm.[3]
General dissipation of rivers and other water sources	The longest river in Denmark is Gudenaaen at 160 km. Although Denmark is relatively rich in water resources, for the most part it consists of flat lands with very little elevation, resulting in low flow rates in its rivers.

Electricity sector overview

In 2013, the total electricity capacity was 13,550 MW. The total net electricity generation was 34,747 GWh (Figure 1).[5] About 46 per cent (15,988.8 GWh) of the electricity generation comes from renewable energy sources with wind being the most important in Denmark. In 2014, the Danish wind turbines delivered what is equivalent to 39.1 per cent of the Danish electricity consumption. This was a new record.[6] Many central and de-central thermal power plants are combined heat and power (CHP) and provide heat to district heating networks (i.e. 73 per cent of district heating is produced by CHP plants).[5] The electricity rate is 100 per cent. In 2013 total electricity consumption was 31,207.[4] GWh (Figure 2).

FIGURE 1

Electricity generation by source in Denmark (GWh)

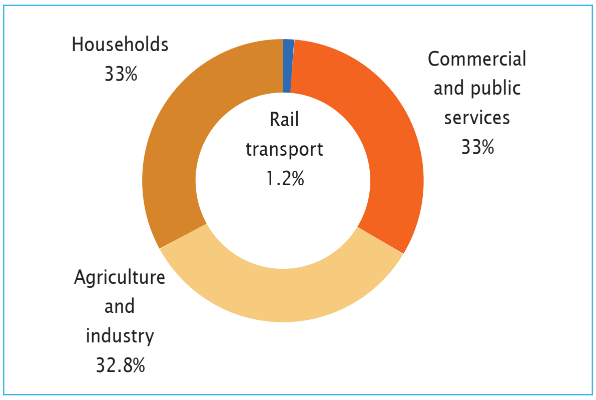


Source: Danish Energy Agency[5]

For general consumption the average electricity tariff in 2015 was DKK 0.96/KWh (approximately US$0.145/KWh).[7] Denmark is also a member of the largest market for electrical energy, the Nord Pool Spot market, which offers both day ahead and intraday markets.

FIGURE 2

Electricity consumption in Denmark (GWh)



Source: Danish Energy Agency[5]

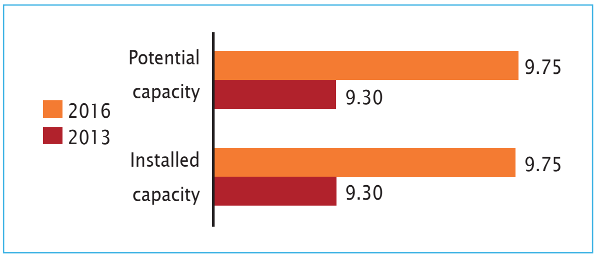
Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Denmark is up to 10 MW. Installed capacity of SHP is 9.75 MW while the hydropower potential is estimated to be 9.75 MW indicating that 100 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*)

2013 and *WSHPDR 2016*, both installed capacity and potential have increased by approximately 4.8 per cent (Figure 3).

FIGURE 3

SHP capacities 2013-2016 in Denmark (MW)



Sources: *WSHPDR 2013*,[15] ESHAIEE[9]

In 2013, Denmark had 42 SHP plants with a total installed capacity of 9.75 MW (13.4 GWh/year).[5] The biggest hydropower plant in Denmark is Tangeværket with a total capacity of 3.9 MW. Defining SHP as less than 10 MW, Denmark, by that definition has no large hydropower plants.[8] Due to the flat nature of the country and to environmental constraints, no further hydropower development is expected.[9]

Renewable energy policy

The Government's goal is a Danish society based on 100 per cent renewable energy in the energy and transport sectors by 2050. In its work to achieve the goal the Government focuses its climate and energy policies on three areas: climate action, energy security and green growth.[10]

In March 2012, the Danish Government entered into a historically broad energy agreement with ambitious energy policy initiatives for the period 2012-2020. The agreement provides 12 per cent reduction of the gross energy consumption in 2020 compared to 2006, over 35 per cent renewable in 2020, and just under 50 per cent wind in the Danish electricity consumption in 2020. The agreement is thus an important milestone in the process of converting all of the energy supply (electricity, heating, industry and transport) to renewable energy by 2050. Among other things the agreement includes the following:[11]

- Energy companies' energy saving efforts be doubled from 2015.
- Develop a comprehensive strategy for energy renovation of existing buildings.
- Establish 1,500 MW of wind capacity in the sea around Denmark.
- Establish 1,800 MW onshore wind turbines, including replacement of 1,300 MW of old mills.
- Support for the development and use of other technologies (solar, wave, etc.).
- Increased incentives to switch from coal to biomass district heating plants.
- Phasing out oil boilers in existing buildings.
- Draw up a smart grid strategy.
- Better frameworks for biogas.
- Support for biogas used for CHP increased significantly.
- Support for the use of biogas in the natural gas grid to process and transport.
- Electricity and biomass in the transport sector.
- Strategy for the promotion of energy-efficient vehicles.
- There is full financing of all new initiatives.
- Energy saving initiatives financed by the company tariffs.
- Support for the expansion of renewable energy financed by PSO.

Legislation on small hydropower

There is support available for hydropower stations of less than 10 MW through the Promotion of Renewable Energy Act.[12] The economic support scheme for SHP is the feed-in-tariff (FIT) of approximately EUR 0.08/kWh for the first 2.5 GWh.[13]

Barriers to small hydropower development

Residual flow requirements are judged individually for each project.[9] However, the main constraints are natural barriers because of the flat nature of the country and environmental constraints.

4.2.2 Estonia

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Key facts

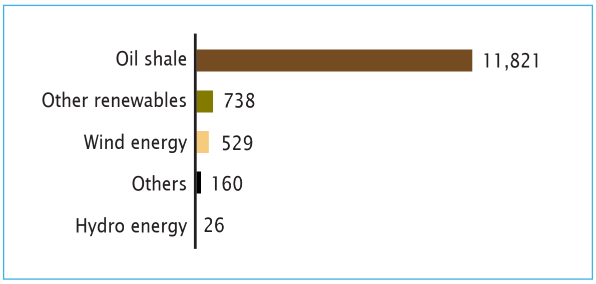
Population	1,315,212[1]
Area	45,227 km²
Climate	Estonia has temperate climate in the transition zone between maritime and continental climates. It has four seasons of near equal length. Winters are moderate and summers are cool. The average annual temperature is 5.2°C. The average temperature is –5.7°C in February and 16.4°C in July.[3]
Topography	Estonia has a flat territory, where highlands and plateau-like areas alternate with lowlands, depressions and valleys. The bases of the highlands are usually between 75 m and 100 m above sea level. The highest point is Suur Munamägi Hill at 317 m. The west Estonian lowland is a swampy plateau, with up to 20-m high limestone hills. Off the Estonian coast, there are 1,521 islands. Estonia is a green land with forests covering 55 per cent of the country.[4]
Rain pattern	Estonia has a humid climate. The annual average precipitation varies between 550 and 800 mm. The coastal zone receives less rainfall than the inland areas. The highest recorded total annual rainfall is 1,157 mm, with a highest recorded monthly rainfall of 351 mm and a highest recorded daily rainfall of 148 mm. The average duration of snow cover during winter is between 75 and 135 days.[3]
General dissipation of rivers and other water sources	There are over 7,000 rivers and streams in Estonia but most of them are short with little water. Approximately 420 rivers are over 10 km in length and only 10 of them have a length over 100 km. Fewer than 50 rivers have an average discharge of greater than 2 m^3/sec and only 14 rivers at over 10 m^3/sec. The largest rivers are: the Narva River, with an average discharge of about 400 m^3/sec; Emajogi, at 72 m^3/sec; Pärnu, at 64 m^3/sec; Kasari, at 27.6 m^3/sec; Navesti, at 27.2 m^3/sec; and Pedja, at 25.4 m^3/sec. The drainage is divided between four basins: Lake Peipsi, the Gulf of Finland, the Gulf of Riga and the islands of west Estonia.[5,6]

Electricity sector overview

Installed electricity generation capacity in Estonia was 2,713 MW in 2014. However, actual net generation capacity is lower as it depends on repairs to the equipment and variable electricity generation from wind and hydropower plants.[7] In 2014, total net electricity generation was 10.9 GWh (13.3 GWh in 2013). Electricity generation is predominantly from oil shale (89.1 per cent in 2013, Figure 1). The total electricity consumption in 2014 was 8.121 GWh. In 2014, 12.4 per cent of gross consumption of the country was supplied by renewable energy.[8] The national electrification rate in Estonia is 100 per cent.

FIGURE 1

Electricity generation in Estonia in 2013 (MWh)



Source: Statistics Estonia[9]

Electricity tariffs in 2014 were EUR 0.0794/kWh for medium size industries and EUR 0.1307/kWh for medium size households (US\$0.09 and 0.15 respectively).[16] The Estonian electricity system forms part of a large synchronous area that consists of the electricity systems of Latvia, Lithuania, Russia and Belarus. Estonia both imports electricity from and exports it to Latvia, Lithuania and Finland. The electricity market became entirely open for all consumers on 1 January 2013 and now the price is determined by the Nord Pool Spot market system.[10]

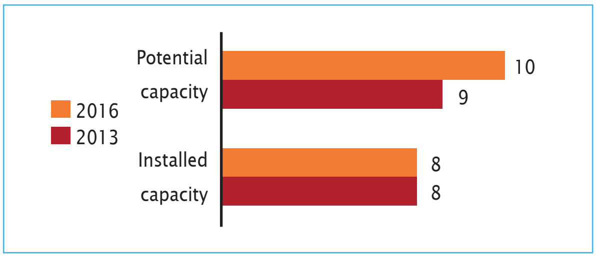
Access to the electricity grid for electricity from renewable energy sources is granted based on the principle of non-discrimination. The grid operator is obliged to develop the grid to guarantee grid services for all electricity producers and to be able to connect further electricity plants to the grid. Additionally, there are a number of investment support schemes available to promote the development, installation and use of renewable energy sources (RES) installations.[13]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Estonia is up to 10 MW. Installed capacity of SHP is 8 MW while the potential is estimated to be 10 MW indicating that nearly 80 per cent has been developed.[6,9] Between *World Small Hydropower Development Report (WSHPDR) 2013* and *WSHPDR 2016*, installed capacity has not increased while estimated potential has increased by approximately 11 per cent (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Estonia (MW)



Sources: Statistics Estonia,[9] *WSHPDR 2013*[17]

In 2011, 47 mostly privately owned SHP plants, ranging from 4 kW to 2 MW, were connected to Estonian national grid.[11] In 2013, their total installed capacity was 8 MW, available capacity was 7 MW and total production was 26 MWh.[9] The country's terrain is relatively flat so rivers have small average slopes and the energy potential of water-courses is rather moderate. Nevertheless there are a number of suitable SHP sites.

Technically feasible potential is less than 30 MW. However, due to restrictions designed to protect fish populations, the current economically feasible potential is considered to be approximately 10 MW.[6] This resource is distributed across four drainage basins: Lake Peipsi (38 per cent), the Gulf of Finland (21 per cent, excluding the Narva River), the Gulf of Riga (32 per cent) and the islands of west Estonia (9 per cent).[5]

There are more than two hundred former water mill sites suitable for SHP but, due to the above mentioned restrictions for protecting fish populations and public concern for the environment, they may not be developed.[6] After 2020 no future growth of hydropower engineering is intended.[11] The only prospective large hydropower site is Omuti, on the border the Narva River, with a possible capacity up to 30 MW.[6]

In line with the European Union Water Framework Directive, a list of 112 rivers (or their reaches) with dams that are preventing the migration of fish has been introduced. This will affect SHP potential. With regard to environmental impact mitigation measures, the conventional measures are fish passage construction for migrating fish watercourses.

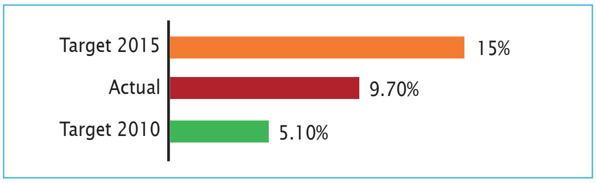
Renewable energy policy

The Electricity Market Act defines renewable sources as hydropower, wind, solar, waves, tidal energy, geothermal energy, landfill gas, sewage treatment plant gas, biogas and biomass.[12] As a member of the European Union, Estonia has prioritised increasing the share of renewable energy in both production and consumption in order to reduce environmental pollution and cut greenhouse gas emissions. Use of renewable energy could also promote energy saving, more efficient production and consumption, energy security, innovation in power engineering and technological development. The Development Plan for the Estonian electricity sector outlines the following:

- The need to reduce environmental emissions from power generation.
- In line with the obligation as a member of the European Union, Estonia will cut CO_2 emissions from the oil shale power plants in Narva between 2012 and 2016.
- The need for more sustainable use of oil shale reserves.
- The aim of making Estonian electricity prices more competitive through carbon emissions trading.[13]
- There are set targets in the Development Plan for the country's renewable energy share from total consumption. In 2010 the target of 5.1 per cent was exceeded by an additional 4.6 per cent. The current target is for 15 per cent by the end of 2015 (Figure 3).

FIGURE 3

Share of the renewable electricity from total gross consumption



Source: Elering[13]

Legislation on small hydropower

In Estonia, electricity from renewable energy sources is mainly promoted through a higher tariff. In addition, investment supports are available for specific types of renewable energy production technologies.[14] Subsidies are paid for electricity that is generated from renewable sources, from biomass in Cogeneration of Heat and Power (CHP) mode or in efficient CHP mode as stated in the Electricity Market Act.[12] The cost of financing the subsidy is passed on to consumers in proportion to their consumption of network services and the amount of electricity consumed through direct lines. A subsidy of EUR 0.0537/kWh (US$0.06/kWh) is paid for electricity produced from biomass in CHP mode and from hydropower, wind, solar, landfill gas, sewage treatment plant gas and biogas and a subsidy of EUR 0.032/kWh (US$0.04/kWh) is paid for electricity produced in efficient CHP mode from waste, as defined in The Waste Act, as well as peat or oil shale retort gas.[13]

Wind power and bio energy-based combined heat and power generation has the greatest potential for renewable energy in Estonia whilst SHP plays a relatively marginal role.

Barriers to small hydropower development

- 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 [15]
- Public support and social acceptance of SHP have been negative lately

4.2.3 Finland

K. Takala, Finnish Energy Industries

Key facts

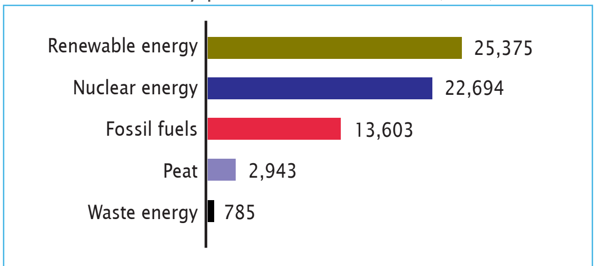
Population	5,463,596[1]
Area	390,905 km[2]
Climate	The temperature is cold, potentially subarctic, but comparatively mild because of the moderating influence of the North Atlantic Current, the Baltic Sea and more than 60,000 lakes.[3] Between 2000 and 2014, the average high temperature was 31.8°C and average low was -39.9°C. Snow cover is usually thickest in mid-March, and often as late as April in Lapland.[2]
Topography	The terrain is mostly low, with flat to rolling plains interspersed with lakes and low hills.[3] The highest point is the Halti mountain in Lapland, at 1,328 m.[5]
Rain pattern	The annual rainfall in 2014 was between 400 mm and 750 mm, depending on the region.[2]
General dissipation of rivers and other water sources	The total length of rivers wider than 20 m is 14,550 km. The longest river route, Poroeno-Lätäseno-Muonionjok-i-Tornionjoki, from the Norwegian border to the Gulf of Bothnia, is 550 km. Most Finnish rivers are relatively short (shorter than 100 km in length). Lakes divide many rivers into several stretches, so some rivers could be called lakes.[4]

Electricity sector overview

The electricity production in 2014 in Finland was 65,400 GWh and the net electricity imports reached 18,000 GWh. In 2014, approximately 74 per cent of total generated power was from greenhouse gas emissions free or carbon neutral sources (including both renewable energy and nuclear power). The share of renewable energy sources was 39 per cent of all electricity production while fossil fuels share was 20.8 per cent (Figure 1).[6]

FIGURE 1

Electricity production in Finland (GWh)

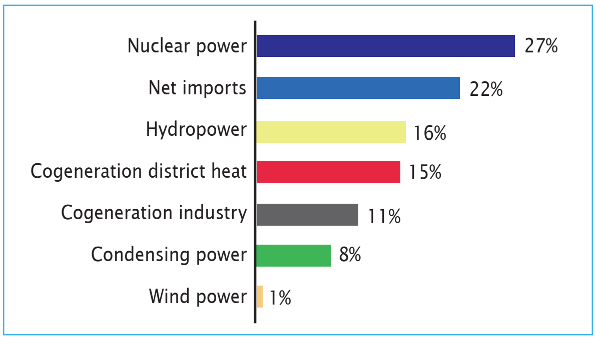


Source: Finnish Energy (2015)[6]

Electricity Consumption in Finland was 83,300 GWh in 2014. Distribution of the electricity supply in Finland in 2014 was as follows: hydropower 15.8 per cent, wind power 1.3 per cent, nuclear power 27.2 per cent, cogeneration 11 per cent, cogeneration district heat 15.1 per cent, condensing power 8 per cent, net imports 21.6 per cent (Figure 2).[6] The industrial sector had the largest share of consumption at 47.2 per cent, largely from the forest and metal industries.[6] All consumers have access to the electricity network.

FIGURE 2

Distribution of electricity supply in Finland (%)



Source: Finnish Energy (2015)[6]

The energy industry has been the largest recipient of investment for many years. All industrial investments in 2014 were estimated to be approximately EUR 5.3 billion (US$5.9 billion), based on the investment survey published in 2014 by the Confederation of Finnish Industries energy investments alone were estimated to be EUR 1.7 billion (US$1.9 billion).[11] However, the low electricity market price has put many investment plans concerning power production on hold.[6]

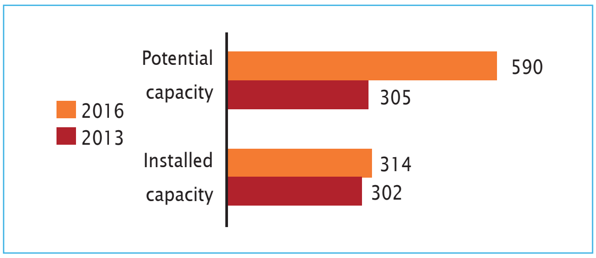
Finland has a deregulated electricity market and is part of the Nordic-Baltic power exchange (Nord Pool Spot), but has its own area price. Electricity users are free to acquire their electricity from the supplier of their choice. Total roll-out of smart metering has been completed and 97 per cent of metering points utilize smart metering. In 2013 slightly over 10 per cent of electricity users switched their electricity supplier. The wholesale electricity prices remained at a low level in the Nordic market in 2014, the same level as in 2007. The prices were held back by the low prices of the European Union (EU), CO_2 emission allowances and the relatively weak demand resulting from the challenging economic situation. The average market electricity price in Finland in 2014 was EUR 0.036/kWh (US$0.04/kWh), approximately 12 per cent lower than the average in 2013. The consumer price is higher, because it includes price for distribution and taxes in addition to the cost of electricity. For example for a detached house owner with no electric heating, (consumption 5,000 kWh/a) the average price in 2014 was EUR 0.152/kWh (US$0.17/kWh).[5]

Small hydropower sector overview and potential

The classification for small hydropower (SHP) plants in Finland is a total capacity of no more than 10 MW. Installed capacity of SHP in Finland is 314 MW and the technical potential is estimated to be approximately 590 MW, indicating that 53 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased only marginally by 4 per (Figure 3).[9,10]

FIGURE 3

SHP capacities 2013-2016 in Finland (MW)



Sources: Ministry of Trade and Industry and Finnish Energy Association,[8] Vesirakentaja Oy,[12] *WSHPDR 2013*[10]

In total, there are approximately 220 hydropower plants in Finland from which 160 are SHP and about half of them are below 1 MW. The average size is 2 MW and average annual production 8 GWh.[12] Additional technical potential is estimated to be up to approximately 710 MW, but 434 MW is in rivers protected by legislation or in border rivers, and this potential cannot be developed.[8] In 2007, it was estimated that technically feasible additional potential in unprotected rivers for SHP is only 63 MW.[9] New SHP in many cases is not commercially viable, therefore there is not a significant amount of new SHP expected to be built in the next few years. In addition, the licensing procedure is long and often costly.

Legislation on small hydropower

The investment support scheme for renewable energy also covers SHP. In 2014, between 15 per cent and 20 per cent of eligible investment costs could be covered by government support.[13] During recent years, it has also been made easier by new rules and recommendations for SHP and other distributed small scale power generation to connect to the grid. Many electricity suppliers also purchase the produced electricity.

Renewable energy policy

Finland has a target as European Union (EU) member country to reach 38 per cent renewable energy sources (RES) of final energy consumption by 2020. A major part of the required addition to RES production is planned to be covered by forest biomass and wind power. In addition, energy efficiency will be significantly improved, which reduces the final consumption. For hydropower the additional production target is 500 GWh/year by 2020 compared to 2005. Finnish Energy has estimated that 70 per cent of the hydropower target will be met, mainly due to refurbishments. Finland has also approved a new national climate act, which sets the greenhouse gas (GHG) reduction target of 80 per cent by 2050 compared to the 1990 level. There is no special price for renewable energy as such. However, some suppliers do offer consumers electricity produced by renewable energy sources.

Barriers to small hydropower development

Due to the low price of electricity most SHP projects are not commercially viable. In addition the permitting procedure is long and requires significant amount of work.

4.2.4 Iceland

Marcis Galauska, International Center on Small Hydro Power

Key facts

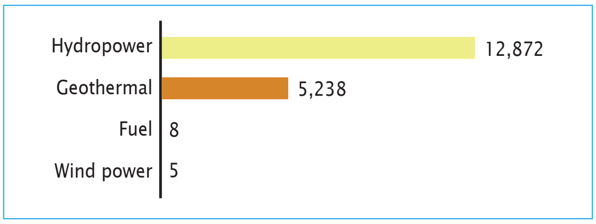
Population	327,589[1]
Area	103,000 km[2]
Climate	Iceland has sub-arctic maritime climate with cool temperatures throughout the year. Summer is between June and August when the weather becomes very mild and sunny with a peak temperature of 13°C. Autumn (September to October) is cool and wet; the average temperature drops to 10°C and 7°C. The winter months, from November to March, are chilly, dark and damp. January is the coldest month, with an average high of 2°C and an average low of -3°C. Spring (April to May) is relatively dry and bright.[30]
Topography	The terrain is mostly plateau interspersed with mountain peaks and ice fields. Its coast is deeply indented by bays and fiords. The highest peak is Hvannadalshnuku at 2,110 m.[2]
Rain pattern	Annual rainfall ranges from 300 to 700 mm in the north, 1,270 to 2,030 mm in the south and up to 4,570 mm in the mountains.[4]
General dissipation of rivers and other water sources	Most of the larger rivers arise from glaciers. Their flow volume is much greater in summer than in winter. Because of the heavy rainfall, Iceland has plenty of rivers and they are relatively large. Thjorsa, the longest, has a length of 237 km and an average discharge of 380 m³/s, while Olfusaa has the greatest flow rate at 440 m³/s. The second-longest river, Jokulsa a Fjollum, is 206 km in length. Other big rivers include Skjalfandafljot, Jokulsa a Bru, Lagarfljot, Skeidara and Kudafljot.[5]

Electricity sector overview

In 2014 electricity generation in Iceland was 18,120 GWh: hydropower produced 12,872 GWh, geothermal 5,238 GWh, fuel 8 GWh, wind 5 GWh (Figure 1).[6] Installed capacity was approximately 2,760 MW and the overall electrification rate was 100 per cent.

FIGURE 1

Electricity generation in Iceland (GWh)



Source: Orkustofnun[6]

Iceland is a scarcely populated country, though the whole country is connected to the power grid, which is rated as one of the most reliable in the world.[7] Orkustofnun is a government agency under the Ministry of Industries and Innovation. Its main responsibilities are mainly: to advise the Government of Iceland on energy issues and related topics, license and monitor the development and exploitation of energy and mineral resources, regulate the operation of the electrical transmission and distribution system and promote energy research. A license issued by Orkustofnun is required to construct and operate an electric power plant, including hydropower. Orkustofnun is responsible for monitoring as well as to regulate the compliance of companies operating under issued licences.[8]

As a result of rapid expansion in energy intensive industries, the demand for electricity has increased considerably. About 71 per cent of overall electricity generation is consumed by the aluminium industry.[9] The National Power Company (Landsvirkjun) is the largest producer of electricity, whose production amounts to 12,469 GWh or 75 per cent of the total, followed by Reykjavik Energy, with 2,138 GWh or 12 per cent of the total. The third company, HS Orka, produces 1,431 GWh corresponding to 9 per cent of the total national production.[9]

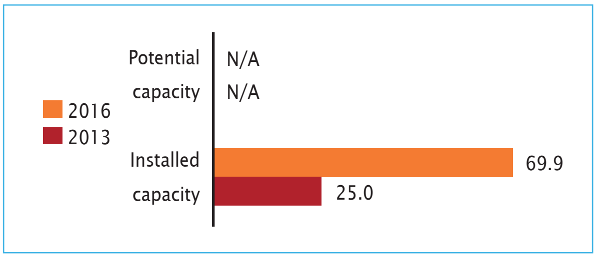
The price of electricity in Iceland is one of the cheapest in Europe at US$0.054/kWh; the costs of generating large amounts of clean electricity in Iceland are low and the end-user markets are near generation locales.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Iceland is up to 10 MW. Installed capacity of SHP is 69.9 MW while the potential is unknown. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has significantly increased (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Iceland (MW)



Sources: *WSHPDR 2013*,[16] Iceland Energy Portal[17]

Much of the precipitation is stored in ice caps and groundwater, and dissipated by evaporation, groundwater flow and glacier flow, with a cumulative energy potential of 220 TWh/year. There are approximately 39 small hydro plants in operation, totalling 69.9 MW (Table 1). However, there is no information about potential SHP capacity.[10]

Since Iceland is already 100 per cent carbon free in heat and electricity production, the renewable energy produced is competitive with all energy sources, without special subsidies.[11]

Renewable energy policy

In Iceland, the generation of electricity from renewable energy sources is promoted by subsidies granted for the design and construction of original tools, equipment for research purposes, the exploitation of energy resources, and for special projects in the field of economical energy use. Access of renewable energy plants to the grid is subject to the general legislation on energy. As 100 per cent of electricity consumption in Iceland is generated from renewable energy sources, RES are not given priority grid connection.[15]

The Icelandic Master Plan for Nature Protection and Energy utilization is an instrument to reconcile the often-competing interests of nature conservation and energy utilization on a national scale and at the earliest planning stages. The idea to create such a plan has been around since the 1980s but work on it didn't begin in earnest until 1999. The Master Plan is currently in its third phase, which is due to be completed in 2017.[12] The previous two phases were Phase 1 from 1999 to 2003 and Phase 2 from 2004 to 2010.

The first phase (1999-2003) evaluated and ranked 20 large-scale hydropower options, mostly located in the highlands, and the same number of geothermal options in eight high-temperature areas. The second phase, 2007-2009, added some 30 to 40 major hydro and geothermal options. The second phase ranked all the options to produce the final result, which was based on the latest research and took into account stakeholders differing criteria. For instance, the second phase included an evaluation of whether some areas should be conserved completely, without any energy-harnessing activities.[13] The third phase of the Master Plan started

TABLE 1

Installed SHP in Iceland (kW)

Site name	Year	Capacity
Selárvirkjun	2007	175
Fjarðarselsvirkjun	1913	160
Bjólfsvirkjun	2008	6,400
Gúlsvirkjun	2008	3,400
Búðarárvirkjun	1930	240
Grímsárvirkjun	1958	2,800
Smyrlabjargaárvirkjun	1969	1,000
Koltunguvirkjun	1928	17
Rollulækjavirkjun	2001	40
Ljósárvirkjun	2007	904
Beinárvirkjun	2003	65
Sandárvirkjun 5	2004	295
Elliðaárvirkjun	1921	3,160
Kiðárvirkjun II	2004	400
Andakílsárvirkjun	1947	7,920
Rjúkandavirkjun	1954	840
Múlavirkjun	2005	3,228
Lindavirkjun	2007	600
Tunguárvirkjun	2002	150
Hvestuvirkjun	2004	1,465
Mjólkárvirkjun	1958	8,100
Sængurfossvirkjun	1976	720
Blævardalsárvirkjun	1975	288
Mýrarárvirkjun	1965	60
Reiðhjallavirkjun	1958	520
Botnsárvirkjun	2002	550
Tungudalsvirkjun	2006	1,000
Fossa-og Nónhornsvatnsvirkjun	1937	1,160
Þverárvirkjun	1953	2,200
Laxárvatnsvirkjun	1953	480
Gönguskarðsárvirkjun	1949	1,064
Sleitustaðir	1986	200
Skeiðsfossvirkjun	1945	4,900
Kerahnjúkavirkjun	2004	370
Djúpadalsárvirkjun	2004	3,117
Glerárvirkjun nýrri	2005	307
Systragilsvirkjun	2000	128
Árteigsvirkjun	2006	500
Köldukvíslarvirkjun	2010	2,000
Laxárvirkjun 2	1953	9,000
Total		**69,923**

Source: Iceland Energy Portal[17]

in March 2013 when a new steering committee was formed. The overarching task in the third phase is to further the evaluation of the energy options that could not be appropriately categorized in the second phase. A number of new energy options will also be evaluated and, for the first time, options in wind power will be considered.[14]

Barriers to small hydropower development

- SHP is not a priority; preference is given to medium and large hydropower plants.
- Lack of state financing means that investors will choose to build bigger plants since it will be more profitable.
- Natural conditions like cold weather and challenging terrain will limit the generation of electricity.

4.2.5 Ireland

Eoin Heaney, The National Trust for Ireland; Marcis Galauska, International Center on Small Hydro Power

Key facts

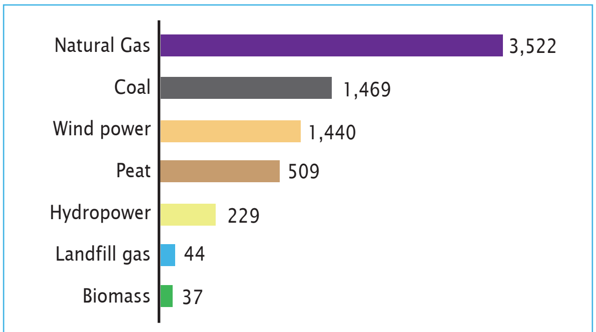
Population	4,609,600[1]
Area	70,273 km²
Climate	The climate is temperate maritime with mild winters and cool summers as well as consistently humid.[2] Mean annual temperatures range between 9°C and 10°C, reaching between 18°C and 20°C in the summer months.
Topography	The terrain is mostly level to rolling interior plains surrounded by rugged hills and low mountains, with sea cliffs on its west coast. At 1,038 m, Carrauntoohil in County Kerry is the highest point in the country.[2]
Rain pattern	Annual rainfall is heaviest in the mountains, exceeding 2,000 mm. In the west of the country, rainfall averages between 1,000 mm and 1,250 mm whereas most of the eastern half receives between 750 mm and 1,000 mm.[3]
General dissipation of rivers and other water sources	Ireland has an abundance of water resources with its more than 12,000 lakes and several hundred rivers. Being an island, it is also surrounded by the Atlantic ocean and the Celtic sea.

Electricity sector overview

Electricity in Ireland is generated from multiple sources. Whilst there is still predominant reliance on fossil fuels, renewable energy, particularly wind, is becoming increasingly important. The main fuel source is natural gas (48.5 per cent, 3,522 MW) followed by coal (20.3 per cent, 1,469 MW), wind (19.8 per cent, 1,440 MW), peat (7.2 per cent, 509 MW), hydro (3.1 per cent 229 MW), landfill gas (0.6 per cent, 44 MW), and biomass (0.5 per cent, 37 MW). Hydropower generated 580 MWh of electricity in 2013 (Figure 1).[4]

FIGURE 1

Electricity generation by source in Ireland (MW)



Source: Sustainable Energy Association of Ireland[4]

The installed deliverable capacity in Ireland in 2014 was 7,383 MW with total electricity production of 24,405 GWh.[5] System availability for the grid as a whole was 88.1 per cent in June 2015.[6] The national electrification rate is 100 per cent.[7] Ireland is ranked 17th out of 141 countries surveyed by the World Economic Forum in terms of reliability of electricity supply.[8]

Eirgrid is the Transmission System Operator in the Republic of Ireland, while further transmission and distribution functions are under the control of ESB Networks Ltd. Following the deregulation of the electricity market, the Commission for Energy Regulation (CER) is responsible for regulating the electricity market as well as other utilities. A single electricity market (SEM) is in operation on the island of Ireland facilitated by the North-South interconnector. The import and export of electricity is also facilitated between Ireland and Britain via the East-West interconnector.

The Government's strategic plan involves the reduction of greenhouse gases, as well as diversification and flexibility of supply. Approximately 60 per cent of the country's electricity already comes from gas fired generation, which adds to energy security concerns, particularly as 93 per cent of its gas supplies come from a single transit point in Scotland. In order to meet the ambitious renewable energy targets and improve the island's level of energy security, the country will need to successfully develop a range of large infrastructure projects.

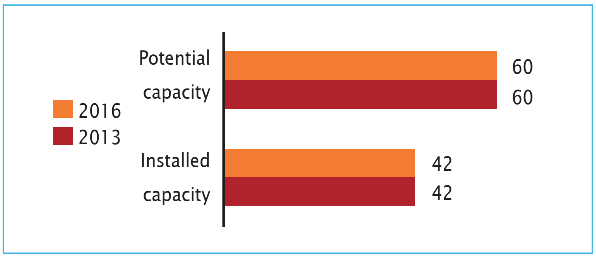
Electricity tariffs in Ireland are deregulated and open to competition. According to Eurostat statistics, the average price for electricity in 2014 was approximately US$0.1/kWh for households and US$0.056/kWh for industry. Previously, until the year 2000 a monopoly was in place operated by the Electricity Supply Board (ESB).[10] The market is regulated by the Commission for Energy Regulation.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Ireland is up to 5 MW. Installed capacity of SHP is 42 MW while the potential is estimated to be 60 MW indicating that nearly 70 per cent has already been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, the installed and estimated capacity has not increased (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Ireland (MW)



Source: Carbon trading LTD,[11] *WSHPDR 2013*[23]

According to the National Renewable Energy Action Plan, hydro and hydro project means any hydro powered electricity generating plant with an installed nameplate rating at or less than 5 MW which is connected directly to the electricity network and metered independently of any other electricity generating plant.[12] Electricity customers in Ireland who install a small generator on site are referred to as micro-generators. ESB Networks classify micro as grid connected electricity generation up to a maximum rating of 11 kW when connected to the three-phase distribution grid (400 V) or 6 kW if connected to the single-phase distribution grid (230 V). The vast majority of domestic and agricultural customers are connected at single phase.[13]

Existing SHP capacity in Ireland is about 42 MW with an estimated generation of 160 GWh per year.[14] This represents approximately 18 per cent of total hydropower. In 2010, two local authorities commissioned reports to identify the SHP potential in their counties. Twenty-seven hydro sites were assessed in County Kilkenny using a calculation tool and producing a map illustrating potential power output. The study identified the hydro resources that can be tapped by local community groups, landowners and local industries. Under the Kilkenny LEADER Partnership Rural Development Strategy 2007-2013, funding is available for the development of renewable energy resources in the county.[15] In 2010, five commercial and five domestic suitable sites were identified for hydropower generation, with a total annual electricity production potential of 1,232 MWh and 116 MWh per year respectively. A further 10 commercial and 100 domestic sites that are financially viable exist in County Clare.

The Irish Hydropower Association estimates, for example, that up to 600 old mill sites around the country could be developed into hydropower generation sites. A reasonable estimate (assuming that not all of these sites are redeveloped) is 25 MW capacity with a production of up to 130 GWh per year. Additionally, 10 more potential high-head sites (each 500 kW) could be developed.[17]

Legislation on small hydropower

The Department of Communications, Energy and Natural Resources operates the country's Renewable Energy incentive scheme Renewable Energy Feed in Tariff (REFIT). The first REFIT 64 scheme (REFIT 1) was announced in 2006 and state aid approval was obtained in September 2007. The current REFIT 2 scheme covers onshore wind, small hydro and landfill gas and was opened in March 2012. The scheme covers projects built and operational between 01 January 2010 and 31 December 2015. The Reference Price for the hydro tariff is EUR 83.81/MWh (approximately US$111.63). This price is subject to market price and a balancing payment, which could effectively increase the value by up to 30 per cent.[18] According to the available data, no significant changes have occurred since 2013. The Government of Ireland is putting more emphasis on the development of wind energy.

Renewable energy policy

Renewable energy policy is largely driven by EU obligations, making it a core element of the Government's energy policy as a whole. This policy is built around the three pillars of:

- Security of supply;
- Environmental sustainability; and
- Economic competitiveness.[19]

The policy is target driven, with a renewable energy contribution to gross electricity consumption of 40 per cent by 2020.[20] The legal framework for renewable energy in Ireland is set out in the country's National Renewable Energy Action Plan, as required by Article 4 of Directive 2009/28/EC legislation.[21]

The main incentive for the development of small-scale renewable energy is the Renewable Energy Feed-In Tariff (REFIT) scheme. The programme provides support to renewable energy projects over a 15-year period. Applicants in REFIT must have planning permission and a grid connection offer for their projects and they will then be able to contract with any licensed electricity supplier up to the notified fixed prices. The fixed price tariffs are:

- Large wind energy (over 5 MW) EUR 0.057/kWh (approximately US$0.076/kWh)

- Small wind energy (under 5 MW) EUR 0.059/kWh (approximately US$0.079/kWh)
- Biomass (landfill gas) EUR 0.07/kWh (approximately US$0.09/kWh)
- Hydro and other biomass technologies EUR 0.072/kWh (approximately US$0.096/kWh) [19]

Barriers to small hydropower development

The development of SHP in Ireland is constrained by a number of factors. It is not on the Government's policy radar, which has chosen wind energy as the most cost effective and feasible renewable energy solution. Furthermore, there is a low level of public awareness. There are also no accredited training courses for the installation of hydroelectric generators.[22]

4.2.6 Latvia

Eva Kremere, International Centre on Small Hydro Power

Key facts

Population	2,025,473[1]
Area	64,589 km[2]
Climate	Latvia has moderately cold winters, while summers are moderately hot. In summer (June to August) the average temperature is 17°C, but can occasionally reach 30°C. During spring and autumn the weather is relatively mild but variable, generally humid with an average temperature of around 10°C. Winters in Latvia usually start in mid-December and last until mid-March. The average temperature in winter is around -6°C, sometimes reaching -25°C.[3]
Topography	Latvia consists of a continental part in the east and the Kurzeme peninsula (Kurland) in the west. The continental part consists of morainic uplands that are crossed by several rivers flowing to the lowlands, of which the main ones are the Daugava, Gauja and Salaca. The highest point of the country is in the Vidzeme uplands with an altitude of almost 312 m above sea level (Gaizinkalns Hill). The continental part is separated from the peninsula in the west by the Lielupe River, which flows through the Zemgales plains. In the peninsula are the Kurzeme uplands, which are lower than the continental uplands and crossed by several rivers, of which the Venta River is the most important. The highest point in these uplands is at 184 m above sea level. About 57 per cent of the country lies below 100 m and only 2.5 per cent lies above 200 m.[4]
Rain pattern	The average annual precipitation is 667 mm.[2] Rainfall is generally higher in the hilly regions, with slopes facing moist air masses, in the western slopes of Vidzeme Upland (700-800 mm), and the western slopes of Kurzeme Upland (650-700 mm), while rainfall decreases on the eastern slopes. Much of the rain (70 per cent) falls from April to October. Maximum rainfall (> 100 mm) occurs in August. Rainfall is less in spring. Precipitation, as constant snow cover, starts around 30 December to 5 January. The thickness of the snow cover exceeds 30 cm in most of Latvia. In its eastern regions, with hilly topography, the snow cover is 40-50 cm deep.[5]
General dissipation of rivers and other water sources	There are 12,500 rivers in Latvia with total length of approximately 37,500 km². The biggest rivers are the Daugava, Lielupe, Venta, Aiviekste and Gauja.[6] Depending on physical and geographical conditions, a large part of the river discharge comes from either snow melt, groundwater or direct surface runoff. Approximately 50-55 per cent of the waters of the Daugava, Venta, Lielupe and Musa Rivers is melted snow, and 35-40 per cent in the Gauja and Amata Rivers.[5] The total renewable surface water resources are estimated at 16.5 km³/year, incoming surface water resources at 18.7 km³/year.[4]

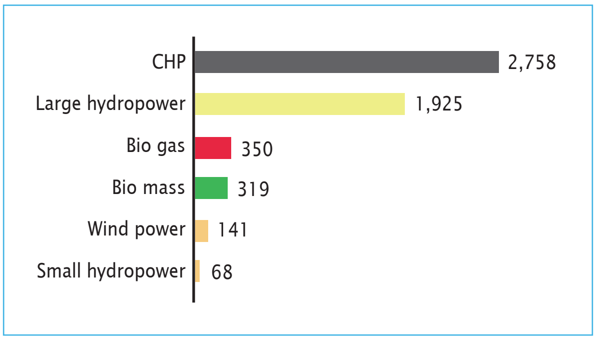
Electricity sector overview

The electricity generation in Latvia is based mostly on large hydropower (approximately 35 per cent) and combined heat and power plants, i.e. fossil fuel (approximately 50 per cent) with the balance coming from imports. In 2014, electricity generation in Latvia was 5,561.4 GWh, installed capacity 3 GW, while total consumption of electricity was 6,583 GWh (Figure 1 and Figure 2).[30,31]

In 2014 2,803 GWh of electricity was produced from Renewable Energy Sources (RES) (50 per cent of the total). However, it was 21 per cent less than in 2013. The greatest share (71 per cent) of electricity from RES was produced in hydropower plants. In 2014, hydropower plants with the capacity over 10 MW (Kegums HPP – 264 MW, Plavinas HPP – 884 MW, Riga HPP – 402 MW) produced a total of 1,925 GWh of electricity or 69 per cent of total electricity produced from RES (Figure 3).[6,32] For the first ten months of 2015, hydropower plants produced 5.1 per cent less electricity than the corresponding period in 2014.[33]

FIGURE 1

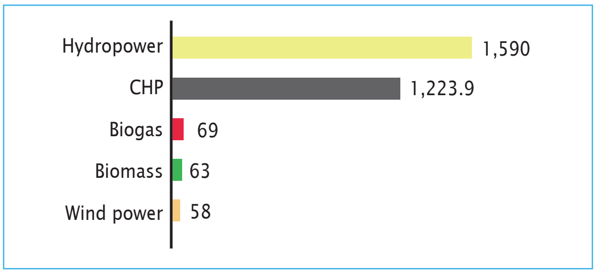
Electricity generation in Latvia (GWh)



Source: Central Statistical Bureau of Latvia[30]

FIGURE 2

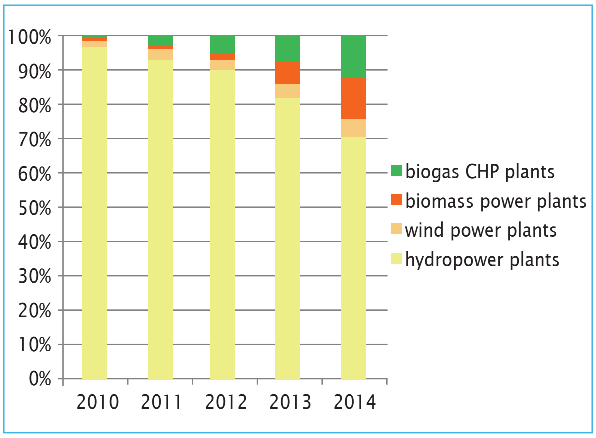
Installed electricity capacity in Latvia (MW)



Source: Central Statistical Bureau of Latvia[30]

FIGURE 3

Electricity production from renewable energy resources (%)



Source: Central Statistical Bureau of Latvia[32]

The electricity market is dominated by two state-owned companies: Latvenergo and Enefit (affiliated with the Estonian state enterprise Eesti Energia).[8] In 2014, AS Latvenergo generated approximately 90 per cent of the total electricity supply, which also ensures electric energy imports and supply to the consumers.[29] In accordance with the European Union requirements, Latvia has been moving towards an open electricity market. In 2007, the Latvian electricity sector was opened for unrestricted competition, allowing households and other non-household consumers to choose an alternative supplier of electricity.[9,10] Compared with other countries' electricity markets which are integrated into the Nord Pool Spot exchange framework, namely Lithuania, Denmark, Estonia, Finland, Sweden, Germany and Norway, Latvian total consumption accounts only for only 1.8 per cent of their total volume (approximately 425,000 GWh).[13,33]

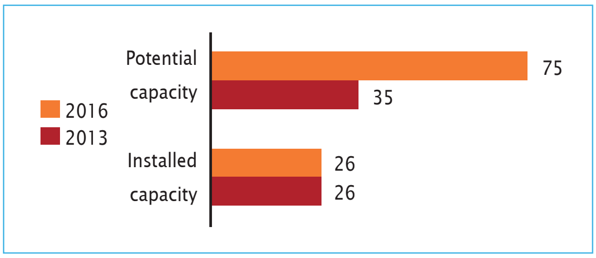
The power transmission network in Latvia is extensive. The main grid consists of 330 kV and 110 kV lines and substations (5,260 km). The distribution network basically consists of 20 kV and 0.4 kV lines, while 6-10 kV is for the cable network. The total length of the network is 94,701 km. There were 46 traders with licenses for electric energy trade. In 2014 six traders were operating actively in the electric energy market having signed contracts JSC Sadales tikls, they are: JSC Latvenergo, LLC Enefit, Ltd. Inter RAO Latvia, SIA BCG Riga, Ltd. Power Source, SIA Hansa Energy, while the public trader license was issued to JSC Latvenergo.[11,13] The Baltic region as a whole has interconnections with Russia (total capacity of 1,450 MW), Belarus (total capacity of 1,100 MW) and Finland (total capacity 350 MW).[13] Electricity prices for 2016 were between EUR 0.15 and 0.181/kWh (US$0.17 and 0.2/kWh), depending on trader and tariff plan.[34]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Latvia is up to 10 MW. Installed capacity of SHP is 26 MW while the potential is estimated to be more than 75 MW indicating that only 35 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has not increased while estimated potential has increased by approximately 37 per cent (Figure 4).

FIGURE 4

SHP capacities 2013-2016 in Latvia (MW)



Source: Latvian Renewable Energy Federation,[17] *WSHPDR 2013*[35]

In 2014 there were 146 SHP plants with a total installed capacity of 26 MW (generating 68 GWh per year).[30] In Latvia only one SHP plant exceeds an installed capacity of 1 MW. The Latvian Renewable Energy Association aims to have 180 plants with a total installed capacity of 48 MW generating 140 GWh by 2020.[12,17] It is believed that the theoretical untapped hydropower potential of small and medium-sized rivers can be estimated at approximately 1,160 GWh. Of these, 260 GWh are located on unusable parts of the Venta, Lielupe, Salaca and Gauja Rivers. Economically feasible potential was estimated between 450 and 500 GWh, but taking into account all the possible constraints and considerations, environmental hydropower potential could be approximately 250-300 GWh.[20]

In the late 19th century, Latvia had more than 700 watermills. Originally, the watermills were powered by wooden waterwheels. SHP plant construction started to expand and by the end of 1926 there were 26 hydroelectric power stations with a total installed capacity of 1.5 MW and a generating capacity of 26.1 MW. During the Soviet era, SHP started to be unprofitable and from 1963 to 1977 all plants were eliminated, even plants which were still working efficiently. All installations were dismantled and scrapped.[6] The Latvian Small Hydropower Association believes that using old watermill locations for SHP development is the best opportunity for development.[20]

TABLE 1

Potential for renewable energy sources in 2020

Type of RES	Installed capacity (MW)	Electricity produced (GWh)	Potential capacity (MW)	Potential electricity (GWh)
Biomass	56	195	150	760
Biogas	50	214	90	720
Wind	75	126	500	1,500
SHP	48	140	75	220
Total	**229**	**675**	**815**	**3,200**
Large hydro	1,522	3,000	1,522	3,000
Total	**1,751**	**3,675**	**2,337**	**6,200**

Source: Latvian Renewable Energy Federation[17]

There has been negative public outlook toward SHP due to the fact that electricity produced by small hydroelectric power plants was relatively expensive due to the FIT tariff.[20]

Renewable energy policy

Renewable energy represents 30-35 per cent of the country's energy mix. Directive 2009/28/EC establishes an obligation for Latvia to increase its share of RES in the gross final energy consumption up to 40 per cent by 2020.[7,22,23,24] In order to help to reach this target the Latvian Renewable Energy Federation has estimated feasible development of RE sources for 2020 (Table 1).

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, small hydro, biomass, biogas, solar). According to this regulation producers can sell their electricity within compulsory procurement with fixed purchase prices (feed-in tariff or FIT system), if the installed electrical capacity exceeds 1 MW.

Legislation on small hydropower

On 1 January 2014, contested amendments to the Natural Resources Tax Law came into force. The contradictory provision in the Natural Resources Tax Law states that owners of hydropower plants with total capacity of the hydroelectric station installed under 2 megawatts have to pay the natural resources tax. The tax rate is EUR 0.00853 per 100 cubic meters of the water that has flown through the hydrotechnical structure. Another provision contested by the claimants deal with the Cabinet of Ministers regulation on the procedure for calculating the amount of water that flows through a given plant. Before that, the natural resources tax did not apply to SHP plants. On 25 March 2015 the Constitutional Court ruled that amendments are not against the Constitution, therefore are in force. Moreover they found that said provisions were not only meant to ensure more efficient and responsible use of natural resources, but also to increase budget revenue that, in turn, could be used to finance environmental protection measures.[16,25,26,27,28]

Latvian SHP development is also limited due to legislative requirements, including the Cabinet of Ministers Regulations No. 27, which protects fishery resources and forbids SHP to build dams.[15,18,19]

Barriers to small hydropower development

Lately there have been several developments that could limit future SHP development:

- In 2011 a moratorium was held to halt new support for SHP through 2013. In 2012 the halt was extended to 2016.
- In 2013 the obligation to fulfil new requests (CHP and RES) for subsidized energy tax amounted to 5-15 per cent of FIT.[23]
- In 2014 a new tax imposed for the water that has flown through the hydrotechnical structure is applied to SHP.[28]

Despite some efforts made by SHP promoters, there has not been any simplification of the administrative procedures for SHP development. Some arguments have been made that previous terms for SHP development were too generous and have harmed the environment.

4.2.7 Lithuania

Egidijus Kasiulis, Aleksandras Stulginskis University

Key facts

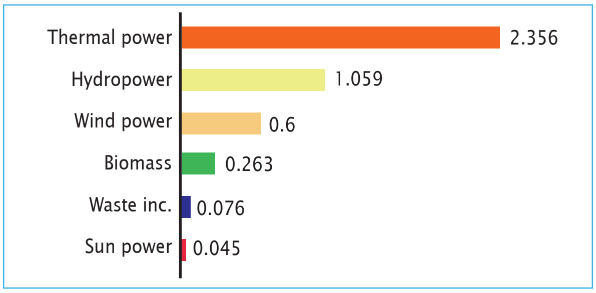
Population	2,919,306[1]
Area	65,300 km^2
Climate	The climate is transitional between marine and continental, with moderate winters and summers, and mostly wet. The average temperature in January is –5°C and in July is 16°C.[3]
Topography	The terrain is mostly lowlands and plains, with the highest peak reaching 293.8 m above sea level. More than a third of the country is covered in forest, with more than half being arable land. Four per cent of the country's territory is covered with water: it has 22,200 rivers and 2,830 lakes. Its coastline extends 100 km along the Baltic Sea on the western side of the country.[2]
Rain pattern	Precipitation patterns are mostly conditioned by the relief. Therefore the average annual precipitation rate in Lithuania varies from 800 mm to 900 mm in 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 summer.[4]
General dissipation of rivers and other water sources	The average density of Lithuanian rivers is 1.18 km/km^2. The highest density of rivers is in central Lithuania at 1.45 km/km^2, while the lowest is in the south-east at 0.45 km/km^2. The highest number of lakes in Lithuania can be found in the north-east of the country. There are 340 artificial ponds in the country that are larger than 50 ha together and few canals, but they are distributed quite equally throughout the country.[5]

Electricity sector overview

After the closure of the Ignalina nuclear power plant in 2009, Lithuania changed from an electricity exporting country to an electricity importing country. In the last few years there has been no noticeable growth in electricity consumption; the average annual amount of consumed electricity between 2012 and 2014 was 9.6 billion kWh, while the average total generated electricity during the same period was 4.4 billion kWh (Figure 1). Consequently it means that 66 per cent of consumed electricity is imported. On the other hand, there is constant growth in the amount of electricity produced from renewable energy sources. The contribution of each source is shown in Figure 1. Total installed capacity of all power plants in the Lithuanian power system in 2014 was 4,304 MW.[6]

FIGURE 1

Electricity generation by source in Lithuania (TWh)



Source: Litgrid[6] (2013)

In accordance with the European Union (EU) directive 2009/72/EC concerning common rules for the internal market in electricity, the electricity sector in Lithuania was liberalized and separate public sector companies were established that are now responsible for the production, transmission and distribution of electricity. The three largest power plants in Lithuania, which are generating approximately 50 per cent of all produced electricity in the country, are the Kaunas hydro power plant, the Kruonis pumped storage power plant and the Lithuanian power plant (thermal power plant in Elektrėnai), and all are state-owned. Other power plants are owned by municipalities or are private. All small renewable energy power plants are owned by the private sector. The electricity consumer is free to choose the provider.[7] Lithuania is fully electrified.

After gaining independence, Lithuania inherited a strong dependence on Russian gas imports as well as the joint electricity network from the Soviet era. Energy independence and security are two ongoing strategic objectives and are being carried out through two major projects, namely creating international electricity interconnections with Sweden and Poland.[7] One project of this type is already finished—the liquefied natural gas terminal in Klaipeda Seaport was opened in 2014.[8] In 2012. Lithuania also became a member of the Nord Pool Spot electric energy market.

The supervision of the state energy sector in Lithuania is carried out by the National Commission for Energy Control and Prices (NCC). NCC is an independent national regulatory authority (according to the European Union law) regulating activities of entities in the field of energy. Every month NCC declares the average market price of electricity. In April 2015, this price was EUR 0.0363/kWh (US$0.04/kWh) without VAT, which is 23.4 per cent less than during the same period in 2014. The monthly average market price of electricity is applied to the producers of electricity from the renewable energy sources via the support mechanism through Public Service Obligations (PSO), i.e. from the budget of PSO the producer gets paid the difference from the fixed feed-in-tariffs (FITs) for electricity from renewable energy sources and the price of sold electricity. However, the fixed FIT for electricity from hydropower plants with installed capacity of below 10 MW has been fixed since 2009 and is EUR 0.078/kWh (US$0.09/kWh).[9]

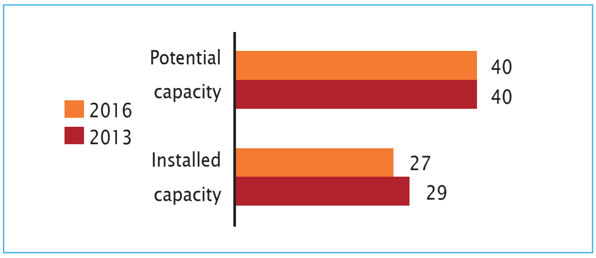
The electricity network that Lithuania inherited from the Soviet Union was modern and able to provide electricity to all consumers even during the case of an accident.[10] During the Lithuanian nuclear power referendum in 2012, the majority of citizens voted against the construction of new nuclear power plants in Lithuania. As a result, although this idea was not totally excluded, no new large energy power projects are planned in the near future. Still, the main challenge in the country in the coming years will stay the same—the pursuit of energy independence and security.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Lithuania is up to 10 MW. Installed capacity of SHP is 26.5 MW while the potential is estimated to be 40 MW indicating that nearly 66 per cent has been developed (Figure 2).

FIGURE 2

SHP capacities 2013-2016 in Lithuania (MW)



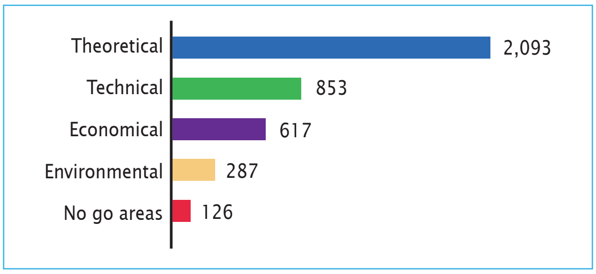
Sources: Litgrid,[6] *WSHPDR 2013*[17]

According to Litgrid, there were 96 SHP in operation in Lithuania with a total installed capacity of 26.5 MW in 2015.[6] Annual generation of electricity from SHP is approximately 100,000 MWh, or 1.6 per cent of the total electricity production in Lithuania.[11] The theoretical, technical and economical capacities for SHP in Lithuania are shown in Figure 3.

Although general opinion concerning SHP in Lithuania has been positive and up to 10 per cent of all generated electricity in Lithuania could come from SHP,[12] in 2004, an amendment to the Water Law was adopted creating no-go areas (in environmentally and culturally valuable rivers) for hydropower (Figure 3) leaving only around 30 rivers suitable for SHP development (which is no more than 5 per cent of the available capacity). As can be seen from Figure 3, the limitations of these no-go areas exceed the environmentally restricted areas for SHP development. As a result, from 2007 the development of hydropower almost stopped in Lithuania. Additionally, the New Renewable Energy Resources Law (adopted in 2011) is promoting dam-less hydrokinetic technologies as less environmentally harmful than conventional SHP.

FIGURE 3

SHP potential capacities in Lithuania (GWh)



Source: Lithuanian Hydropower Association[12]

Subsidies and public support actions are very limited in Lithuania, thus most funding of SHP was accomplished by the private sector.[13] For example, in 2013, from all the investment channelled into the renewable energy sector, 47.3 per cent were loans from banks and only 2.4 per cent was support from the EU and 0.2 per cent from regional and governmental subsidies.[14] There is a possibility to get funding from EU structural funds if heritage sites such as old watermills are refurbished. Still, if the mill is on one of the environmentally and culturally valuable rivers, there is no possibility to rebuild the old watermill's dam. So far, the most popular funding source for SHP is also long-term loans from commercial banks.[13]

Legislation on small hydropower

Strict environmental laws in Lithuania are limiting the development of hydropower. The Law on Environmental Protection of 1992 (amended in 2010 as No XI-858) requires environmental impact assessments to be carried out for any projects that may have an effect on the environment. Likewise, several Resolutions and nine Orders were issued in 2003 and 2004 regarding the use of water sources in the country. As a result, since 2007 only 14 new SHP plants were commissioned, or roughly 1.6 plants per year.

Although, there is a possibility to get EU support to refurbish old water mill sites, rarely is there a possibility to rebuild an old mill's dam.

Renewable energy policy

Renewable energy policy in Lithuania is shaped according to two EU directives: Directive 2006/32/EC on energy end-use efficiency and energy services and Directive 2009/28/EC on the promotion of the use of energy from renewable sources. The main documents governing the development of the renewable sources in Lithuanian are: the Renewable Energy Resources Law, National Energy Strategy and National Renewable Energy Strategy together with its Action Plans.[15]

In 2013, according to Eurostat, Lithuania reached its 2020 goal of 23 per cent share of renewable energy in gross final energy consumption.[16] This intermediate result indicates that Lithuanian renewable energy policy has been successful. Clarification can be found in the National Commission for Energy Control and Prices annual report to the EU concerning the national electricity and natural gas markets in 2013.[14] In 2013, there were 7.2 times more permissions issued to generate electricity from renewable energy sources than in 2012.

Electricity generation from all renewable energy sources are supported via FITs. As it was mentioned above, the FIT for SHP is EUR 0.078/kWh (US$0.09/kWh). For other small renewable energy plants (< 10 MW) they are as follows: wind – EUR 0.078/kWh, biomass – EUR 0.081/kWh, waste incineration – EUR 0.113/kWh, solar – EUR 0.156/kWh (US$0.09, US$0.09, US$0.13, and US$0.17/kWh respectively).[9] Also, there are discounts for connections to the electricity network, no balancing responsibility and other support measures. Unfortunately, in the same *National Commission for Energy Control and Prices Annual Report* to the EU there is a note that the development of the electricity generation from renewable sources will be balanced by reducing the electricity purchasing tariffs and revising the authorization procedures.[14]

Two important strategies were passed by the Lithuanian Parliament in 2012: (a) the National Climate Control Policy Strategy, and (b) the National Energy Independence Strategy. In the first document, the support to renewable energy is declared, and as a goal the same 23 per cent share of renewable energy in gross final energy consumption was repeated. Both documents state that tapping the hydropower potential of the country is a priority. Still, in the National Energy Independence Strategy there is a specification that only the hydropower potential that does not adversely affect the environment should be developed and the values stated earlier in the Renewable Energy Resources Law are repeated. The goal for hydropower is to reach the potential of 141 MW of installed capacity by 2020.

According to intermediate statistics, the Lithuanian renewable energy policy was successful and the share of renewable energy in the gross final energy consumption in 2013 was exactly the same as the goal set for 2020. Still, although tapping the hydropower potential is a priority, Lithuania has some of the strictest environmental regulations for hydropower development in the EU.

Barriers to small hydropower development

Lithuania is a lowland country and the hydropower resources are not abundant. However, the majority of it is still untapped. More than 100 years of operational hydropower in Lithuania has proved to be a reliable, efficient and safe source of electricity. The grand barrier to SHP development in Lithuania is the legislative package regulating environmental constraints, which is stricter than EU adopted directives on this matter.

4.2.8 Norway

Fredrik Arnesen, Seming H. Skau and David E. Weir, Norwegian Water Resources and Energy Directorate

Key facts

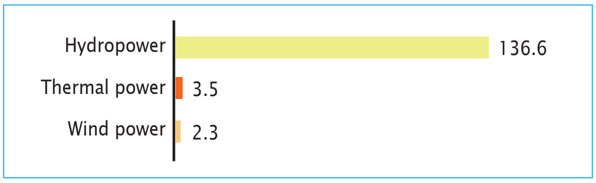
Population	5,165,802[1]
Area	323,772 km^2 [2]
Climate	Norway covers 13 degrees of latitude and therefore has a large variety in climate and temperature. Temperatures are generally warmer along the south-west coast and colder further inland. The winter period lasts between December and February when mean 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]
Topography	The terrain is rugged and mountainous, with the Scandes Mountains stretching the length of the country. The highest mountains are in the south with many summits over 2,000 m above sea level. In many areas the mountains have characteristic steep sides and flat or rounded tops. This is especially true 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 m.[3]
Rain pattern	There are large differences in the normal annual precipitation in Norway. West Norway experiences the largest amounts, in excess of 4,000 mm annually. In these areas frontal and orographic precipitation dominates, and most of the precipitation is received during the autumn and winter months (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, the driest.[3]
General dissipation of rivers and other water sources	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, at 604 km, and the largest lake is Mjøsa, which is 362 km^2.[3]

Electricity sector overview

As of 1 January 2015, the installed capacity in Norway was approximately 32,500 MW. In 2014 the total generation in Norway was approximately 142.4 TWh. 136.6 TWh, or 96 per cent, was generated from hydropower with a combination of wind and thermal power generating the remainder (Figure 1).

FIGURE 1

Generation by source in Norway 2014 (TWh)

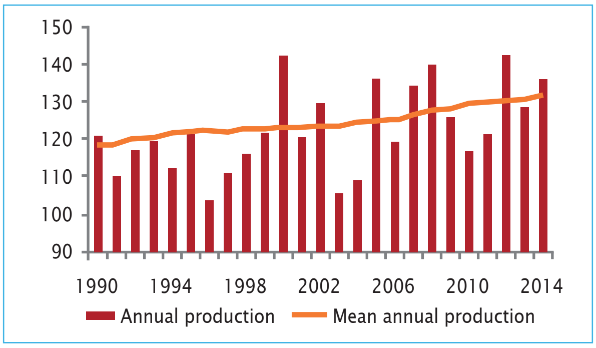


Source: Statistics Norway[6]

Due to the huge share of hydropower, the exploitable inflow is the most important input factor in the Norwegian power system. Exploitable inflow is the total amount of the inflow each year that can be utilized for power production.[4] The mean annual hydropower production of all the hydropower plants installed before the beginning of 2015 was 131.9 TWh. However, there is a significant inter-annual variation in exploitable inflow for hydropower production around 20 per cent, affecting the output of the plants (Figure 2).

FIGURE 2

Annual hydropower generation 1990-2014 (TWh)



Source: Statistics Norway[6]

In Norway, both power production and power consumption peak during January. The inflow, however, peaks during between April and May. About half of Europe's total hydropower reservoir capacity, approximately 84 to 85 TWh, is located in Norway.[5] Much of this reservoir capacity is used to capture inflow from the summer season for power production during the winter season, in order to meet the variability of the demand.

The electrification rate is 100 per cent. The last three years the average net electricity consumption has been 116 TWh.[6] Forecasts predict an increased population, higher private consumption and a greater proportion of urban residents. About one third of the electricity consumption is energy intensive industry and this sector is dependent on the world marked, policy and electricity prices. A 2012 energy report estimates that by 2030 electricity consumption could increase to between 63 TWh and 185 TWh compared to figures from 2009.

All grid owners are obliged to give a connection to the grid to all new production units. The obligation to connect applies to the existing grid. In an area with many new producers but limited available capacity, the first 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.[7]

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.[4] Since then the Norwegian power market has opened to competition and today Nord Pool Spot organizes the Nordic marketplace for trading electricity with a share of 84 per cent of total power consumption in 2004.7 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.[8]

The Government regulates the transmission and distribution tariffs based on regulations laid down in accordance with the Energy Act. The Norwegian Water Resources and Energy Directorate (NVE) determines annual revenue caps for each individual license 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 given effective operation, utilization and development of the network.[9] The average price of electricity for households in the first quarter of 2015, excluding taxes and grid rent, was NOK 31.3 (US$3.79) per kWh. This is 0.6 per cent lower compared to the same quarter in 2014 (Table 1).[10]

Small hydropower sector overview and potential

In Norway, power plants with a total capacity of 10 MW or less are classified as small hydropower (SHP) plants. SHP installed capacity in 2015 was approximately 2,242

TABLE 1

Tariff rates Q1 2015

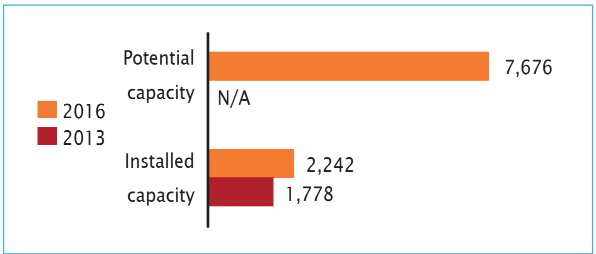
Tariff type	Tariff (Norwegian Krone/kWh)	Change in last 3 months (%)	Change in last 12 months (%)
Households			
Total price of electricity, grid rent and taxes	86.4	1.5	1.9
Electricity price	31.3	-1.3	-0.6
Grid rent	26.3	1.2	1.2
Taxes	28.8	5.1	5.5
Households (Electricity price by type of contract. Exclusive of taxes)			
New fixed-price contracts 1 year or less*	33.6	0.3	0.6
New fixed-price contracts- year or more*	32.1	-1.2	-10.3
All other fixed-price contracts	33.4	-2.6	-7.7
Contracts tied to spot price	29.1	-4.3	-0.7
Variable price (not tied to spot price)	36	3.7	0.6
Business activity (Electricity price. Exclusive of taxes)			
Services	29.1	-4.6	-2.7
Manufacturing excl. energy-intensive manufacturing	28.9	-0.7	1.8
Energy-intensive manufacturing	30	1	2.4

Source: Statistics Norway[12]
*New fixed-price contracts are entered into the last 3 months before the measuring period, and older fixed-price contracts are entered earlier.

MW with an estimated additional technical potential of 5,434 MW of which approximately 1,941 MW (35 per cent) is calculated from known projects that are under construction, have been given licences or have applied for licences.[5] This indicates that over 50 per cent of the known potential and approximately 30 per cent of the technical potential has been developed.

FIGURE 3

SHP capacities 2013-2016 in Norway (MW)

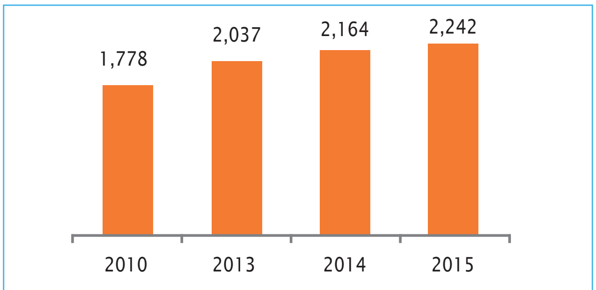


Sources: Ministry of Petroleum and Energy,[16] *WSHPDR 2013*[11]
Note: The figure compares data reported in *WSHPDR 2013* and *WSHPDR 2013*.[6] The range of data covers 2010 and 2015.

According to data from the NVE, in 2013 installed SHP capacity was 2,037 MW indicating an increase of approximately 10 per cent by 2015. Compared with *World Small Hydropower Development Report (WSHPDR) 2013*, the installed capacity was 26 per cent higher than earlier reported (Figure 3).

FIGURE 4

SHP installed capacity development (2010-2015) (MW)



Source: Various[11,16]

In 2015 there were approximately 1,510 hydropower plants in the country, 1,175 (78 per cent) of which are SHP plants. Approximately 70 per cent of these are run-of-river. Combined, they contribute approximately 7 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 SHP plants were closed down due to the interconnected net grid and economic viability of new power stations. After the deregulation of the electricity market in 1991 there was more or less stagnation in construction of new hydropower plants due to overcapacity and low prices on electricity. This has, however, changed in the last decades, which have seen an increase in the development of new SHP projects. 721 out of the 1,175 (61 per cent) SHP plants in Norway were built during the period from 2000 to 2014.

There is still considerable interest in developing new SHP plants in Norway. At the beginning of 2015, 651 licence applications for new SHP plants were under consideration by the authorities (Ministry of Petroleum and Energy and Norwegian Water Resource and Energy Directorate). In addition, there were 443 licensed projects which had not yet expired or been realized. The potential capacity from known projects that are under construction, have been given licences or have applied for licences is estimated at 1,941 MW. While there is a technical potential for an additional 3,493 MW this figure may be misleading as a large share of these sites are unlikely to be granted a license.

TABLE 2

Operational hydropower stations by size and mean annual production

Plant size	Numbers of plants	Installed capacity (MW)	Generated capacity (TWh)
<1 MW	554	175	0.8
1-10 MW	587	1,989	8.3
10-100 MW	255	9,523	43
> 100 MW	80	19,273	79.5
Total	**1,476**	**30,960**	**132**

Source: Ministry of Petroleum and Energy[16]
Note: Data as of 1 January 2014.

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 rural areas. Many local developers of SHP plants were not familiar with the process of establishing and operating a new power plant. 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.[12] It is based upon the Swedish electricity certificate scheme, which has been in place since 2003. The goal is to increase the annual renewable electricity production in both countries combined by 26.4 TWh by the end of 2020. This represents approximately 10 per cent of the current electricity production of the two countries. Norway and Sweden are each responsible for financing half of the new production in the certificate system, regardless of where the new production capacity is established. The electricity certificate scheme will contribute to the achievement of the countries' goals under the EU's Renewable Energy Directive. The common electricity certificate market is due to continue till the end of 2035. Within the electricity certificate scheme, approved power plants receive one certificate for each megawatt hour (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 2012-2015, Norwegian producers entitled to certificates received an average of approximately EUR 20/MWh produced (based on the average spot price of certificates). The demand for certificates is created by a requirement under the act that all electricity users purchase certificates equivalent to a certain proportion of their electricity use, known as their quota obligation.

This support scheme is technology neutral, which means that all energy sources defined as renewable energy qualify for participation in the electricity certificate market.[13] As of July 2015 about 120 SHP plants in Norway have been granted the right to participate in the electricity certificate market which is included in the goal of 26.4 TWh.[14] To be eligible for the market the hydropower plant must be built in accordance with the license and commissioned after 1 January 2012. In addition, new hydropower plants commissioned after 1 January 2004 can be certified. However, they are not included in the goal of 26.4 TWh.[15] In Norway it is assumed that most of the new production developments motivated by electricity certificates will be hydro and wind power.

Barriers to small hydropower development

The price in the electricity certificate market adds approximately NOK 0.15/kWh (US$0.02/kWh) to the energy price. Between 2012 and 2015 the electricity price has been low compared with previous years. The consequence is that many projects with a valid licence are not built so far. Furthermore there are areas in Norway which have problems with access to the grid; both from the local grid and from the central transmission system.

At the beginning of 2015 there were 443 licensed, but yet unrealized, SHP projects. In 2014, the holders of 210 licences were interviewed and it was reported that 123 of these investments were held back either due to the project's economy, the lack of grid access or both.

4.2.9

Sweden

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Key facts

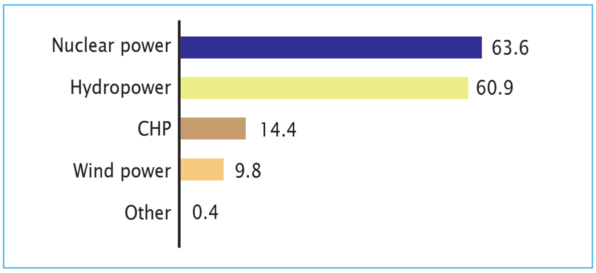
Population	9,747,355[1]
Area	450,295 km[2]
Climate	Sweden is temperate in the south, with cold, cloudy winters and cool, partly cloudy summers, and subarctic in the north. The hottest month is July, with an average temperature of 17.5 °C, while the coldest is February at -7.5 °C.[2]
Topography	The terrain is mostly flat or gently rolling lowlands with mountains in the west, slopping from the north (Norrland) to the Gulf of Bothnia. The highest point is Kebnekaise, at 2,111 m.[3]
Rain pattern	The rainiest seasons are summer and autumn, with annual rainfall typically around 500 mm to 800 mm. The mountains average 1,500 mm to 2,000 mm while the south-west areas have 1,000 mm to 1,200 mm. The small islands along the Baltic Sea and confined valleys in the mountain regions have the least rainfall, with around 400 mm per year.[2]
General dissipation of rivers and other water sources	There are plenty of streams, rivers and lakes in the Swedish landscape. The total length of rivers and streams is about 192,000 km. There are 119 main water courses that are defined as rivers that end in the sea and have a watershed area of more than 200 km.[3]

Electricity sector overview

In 2014, total installed capacity in Swedish power plants was 38,273 MW of which 16,155 MW was from hydropower.[5] In 2015, total electricity generation in Sweden was 149 TWh with approximately 42 per cent from nuclear power, 41 per cent from hydropower, 10 per cent from combined heat and power plants and 7 per cent from wind power. Other sources including solar, cold condensing power and gas turbines contributed a negligible amount.[4] Swedish carbon emissions associated to electricity are low compared to other countries, as more than 90 per cent of the electricity comes from wind, nuclear and hydropower (Figure 1).

FIGURE 1

Electricity generation by source in Sweden (TWh)



Source: SCB[4]

The electrification rate and access to the electricity grid in Sweden is effectively 100 per cent although some remote houses could still lack access to the electric grid.[6] The per capita use of electricity in 2013 was 14,500 kWh per year.

There are relatively large differences in the power and energy demands for summer (June to August) and winter seasons (December to February). High power demand during cold winter days will put the highest pressure on the power system. In 2014, hydropower contributed 41 per cent of the total installed power generating capacity. Hydropower stations are both run of river and reservoir types. The reservoir hydropower is used for short balancing the system and enables intermittent power production to be integrated into the system.

The main new renewable energy production in recent years has been from new or converted Combined Heat and Power (CHP) plants using biomass as well as new wind power capacity.

The power market is deregulated and much of the power is traded on the Nord Pool Spot market. Energy Markets Inspectorate is the industry regulator responsible for supervising compliance with laws and regulations. The price of the traded power will differ depending on operational parameters and mix of generating capacity. The system price at the spot market (Elspot) averaged to EUR 28.10 (US$37.43) per MWh in 2013.[7] The average consumer tariff in the latter half of 2014 was EUR 0.187 (US$0.249) per kWh for households and EUR 0.067 (US$0.089) per kWh for industries.[22]

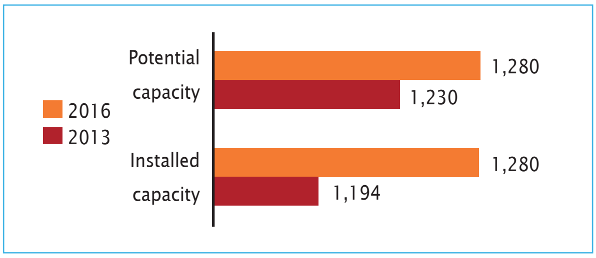
Small hydropower sector overview and potential

As part of the European Union (EU), Sweden defines small hydropower (SHP) as up to 10 MW installed capacity. However, it is not uncommon to find reference to hydropower with an installed capacity of less than 1.5 MW, which is an old categorisation. In some legislation this older categorisation is still used. Due to the high number of hydropower stations with an installed capacity below 1.5 MW it is still important to keep track of these categories within Sweden.

Installed SHP capacity (up to 10 MW) is approximately 1,280 MW. However, given the present overview of environmental conditions for operation, there is currently limited room for future development of new SHP sites.[11] There is still potential to expand installed capacity and electricity generation by improving the efficiency in already existing installations. In comparison to *World Small Hydropower Development Report* (*WSHPDR*) *2013*, installed capacity has increased by approximately 7.2 per cent. However, this increase is likely due to an underestimation in the previous report rather than an actual increase to this extent in SHP capacity in the intervening period (Figure 2).

FIGURE 2

Small hydropower capacities 2013-2016 in Sweden (MW)



Source: StreamMap,[11] *WSHPDR 2013*[21]

In Sweden, the first hydropower station was built in the mid-1880s. From the beginning of the 20th century through the beginning of the 1970s, Sweden saw a steady expansion in hydropower capacity. The industry had a secure power supply and alongside this the country was electrified. In 1975 the Government formulated a target of hydropower contributing 66 TWh to the energy balance by 1985 which was subsequently achieved.[9,10] In 2012 there were approximately 1,900 SHP plants in Sweden with a total installed capacity of about 1,280 MW, generating 4,400 GWh per year (normalized) (Table 1).[11] This accounts for 6 per cent of the hydropower production in Sweden and 4 per cent of the total installed capacity.[12] 1,700 of the SHP plants have an installed capacity of less than 1.5 MW and produce approximately 1,400 GWh. Approximately 70 per cent of total electricity generation from SHP in Sweden comes from plants with an installed capacity between 1.5 MW and 10 MW.[12] Most SHP stations are run-of-river types and hence the production is dependent on the flow in the river and there is no balancing or regulating capacity found in these power plants.

The five largest hydropower owners in Sweden produce approximately 93 per cent of the total hydropower electricity generation. SHP stations are more commonly found in the southern parts of Sweden while the large hydropower stations are more typical for the northern regions. About 40 per cent of the hydropower stations with installed capacity below 1.5 MW are privately owned.

There are three overarching goals set by the Government in relation to hydropower in Sweden. The first relates to concession rights. Water operation in Sweden should possess concessions that are in line with Swedish environmental legislation and EU regulations. The second goal relates to production where the aim is to maintain both production and balancing capacity for hydropower in Sweden. The last goal is that this should all be done efficiently.[8]

There are at present no specific government targets on increasing capacity of hydropower in Sweden. Yet, nor are there any limitations for expansion as long as projects align with environmental regulations as well as other legislation relating to dam safety and construction regulations. There is little expansion or change of the number of SHP production in Sweden. The Swedish Energy Agency has determined that the main new potential in hydropower in Sweden is found in modernizing and improving efficiency in existing hydropower plants. There has been an average increase of installed capacity in Swedish hydropower during the last 20 years of about 15 MW per year. Typically around 3 MW/year of this increase is found in the category of SHP.

The main discussion on hydropower (both small and large) in recent years has been how to align existing hydropower stations with modern legislation. In 2014 the Swedish Energy Agency and the Swedish Agency for Marine and Water Management presented a policy on how this could be done.[13] In short it sets certain guidelines and priorities for different water catchment areas. The majority of energy and regulating capacity today is found in large hydropower stations.

SHP contributes to energy production but is also part of Swedish cultural heritage. At the same time there is a documented need to improve the environmental status in many affected rivers and streams in order to satisfy the Swedish Environment Objectives[ii].[14,15] Thus, in light of the energy policy of Sweden and the Environmental Objectives, the number of SHP stations seems unlikely to rise in the next 10 years. There is a certain potential to increase the installed capacity in already existing stations but this comes with a cost.

In recent years there are a number of fauna passages or bio-channels built around SHP stations. This have the potential to reduce the fragmentation in the river that is caused by the hydropower dam construction.[24] As many of the SHP stations are old and new ecosystems have been established stakeholders linked to the owners of SHP have raised concerns about the costs and net-benefits

TABLE 1

Data on small and large hydropower in Sweden

	Installed capacity (MW)	Number of plants	Estimate of cumulated installed capacity (MW)	Estimate of share of total hydropower electricity production (%)
Small hydropower	< 0.125	~1,030	40	0.5
	0.125-1.5	~680	410	2.1
	1.5-10	187	830	3.9
Large hydropower	> 10	208	14,875	93.5

Source: StreamMap,[11] *WSHPDR 2013*,[21] Sea and water authority,[13] Kling, J.[23]

of these installations. All stakeholders acknowledge the input to the energy system that hydropower makes but due to the old permits linked to many of the existing SHP stations, environmental organizations are not actively pushing for SHP as a better alternative to large hydropower. Environmental organizations such as Naturskyddsföreningen (Swedish Society for Nature Conservation) actively support environmental improvements in existing hydropower through its eco-labelling scheme, Bra Miljöval (Good Environmental Choice) and the environmental funds generated from the purchase of the labelled products.

Renewable energy policy

In 2009, Sweden surpassed its EU Renewable Energy Directive 2020 renewable energy targets of 49 per cent share of final energy from renewable sources by 2020, achieving 50.2 per cent.[17] In 2013 the share of renewable energy was 52.1 per cent.[18] A market-based support system for renewable electricity production has been in place in the form of electricity certificates since 2003. The objective of the Swedish electricity certificate system is to increase the production of renewable electricity by 25 TWh by 2020. Since 1 January 2012, Sweden and Norway have a common electricity certificate market. Over the period until 2020, the two countries aim to increase their production of electricity from renewable energy sources by 28.4 TWh. The joint market permits trading in both Swedish and Norwegian certificates and receiving certificates for renewable electricity production in either country. There are no feed-in tariffs (FITs) or other direct support structures for SHP in Sweden.

Legislation on small hydropower

There is the potential to increase production in SHP in Sweden by improving efficiency in existing hydropower stations. Many older SHP plants are now being phased out of the Swedish green certificate support scheme. To be entitled to operate for the next 15 years, it is required that the plants must undergo total refurbishment of all essential parts. As refurbishment is very expensive and not always economically viable for smaller plants (approximately less than 100 kW), many SHP stations could face an uncertain future.[19] The green certificate market is a technology neutral instrument and there are no targets set specifically for new hydropower capacity in Sweden. From 2007 onwards, not many new plants have been built but refurbishment is being made, including upgrading larger SHP plants. But typically there is a higher cost per produced kWh as compared to large hydropower and the economic incentives are weak (especially for the large number of hydropower stations with installed capacity of less than 1.5 MW) to undertake modernizations of equipment or improve the environmental status of the affected water.

Barriers to small hydropower development

The EU Renewable Directive 2009/28/EC (by 2020) has not resulted in any changes for SHP in Sweden. The EU Water Framework Directive is implemented under Swedish Law and the effect of the directive in reality will only be known after a Swedish court ruling.

The water concessions that are linked to the hydropower stations in operation today are in most cases based on older legislation. For example 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 even older legislation.[19]

There are direct costs involved in getting new concession rights that are in line with modern legislation. Apart from putting together the application there might be requirements to alter and modify the hydropower station. In addition, another requirement might be that hydropower plants are required to spill water corresponding to 5 per cent of the total water flow resulting in reduced electricity production.[20] The motivation behind this is to improve the ecological status of rivers.

Notes

i This report is a revised and updated version based upon the 2012 report by Small Hydropower Association, Stream Map

ii There are 16 Environmental Objectives. Flourishing Lakes and Streams is one of the objectives linked to hydropower as these installations will affect biodiversity, hydro morphology and other environmental parameters in lakes and watercourses.[16]

4.2.10 United Kingdom of Great Britain and Northern Ireland

Gabrial Anandarajah, UCL Energy Institute

Key facts

Population	64,596,800[1]
Area	248,531.52 km[2]
Climate	The climate is temperate, with the Gulf Stream ensuring mild, maritime influenced weather. Temperatures range from not much lower than 0°C in the winter months between December and February and not much higher than 32°C in the summer months between June and August. The temperatures in Scotland are generally lower than that in the other parts of the country.[4]
Topography	The United Kingdom is divided into hilly regions of the north, west and south-west and low plains of the east and south-east. The eastern coast of East Anglia is very low lying, much of it lower than 5 m above sea level. All the top ten highest peaks are located in either Wales or Scotland. The highest point is Ben Nevis, reaching 1,343 m.[5]
Rain pattern	The mountains of Wales, Scotland, the Pennines in Northern England and the moors of south-west England are the wettest parts of the country. Some of these regions receive more than 4,500 mm of rainfall annually, making them some of the wettest locations in Europe. Other regions can be very dry, with the south and south-east regions receiving an annual average of less than 700 mm.[4]
General dissipation of rivers and other water sources	The longest river is the Severn (350 km), which flows through both Wales and England, and the second longest is the Thames (322 km). Other major rivers in England and Wales include the Humber, Tees, Tyne, Great Ouse, Mersey and Trent Rivers. Scotland's river system is largely separate from that of England. The two major rivers of Scotland's central lowland are the River Clyde and the River Forth. Scotland's longest river is the River Tay (188 km). As a result of its industrial history, the United Kingdom has an extensive system of canals, mostly built in the early years of the Industrial Revolution.[3,4]

Electricity sector overview

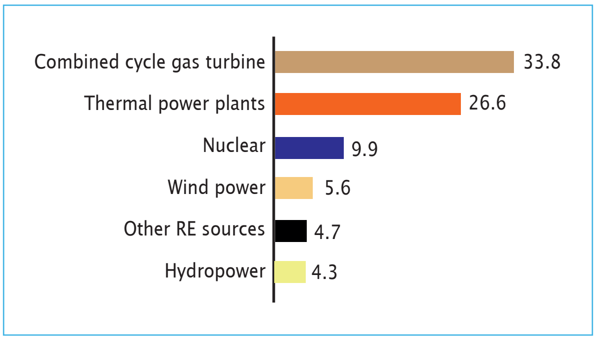
Electricity infrastructure in the United Kingdom of Great Britain and Northern Ireland is well developed with a 100 per cent electrification rate. In 2014, total installed capacity was 85 GW. Approximately 40 per cent is from combined cycle gas turbine plants, 31 per cent from conventional thermal power plants (utilizing both coal and gas), 12 per cent from nuclear plants, 7 per cent from wind power, 5 per cent from hydropower plants (including pumped storage facilities) and a further 5 per cent from other forms of renewable energy (Figure 1).[6]

In 2014, total electricity generation was 336 TWh, of which renewable energy accounted for 19 per cent. Gas and coal powered plants dominated the generation mix contributing a combined 60 per cent to total generation. Nuclear provided 19 per cent while wind, wave and photovoltaic contributed approximately 11 per cent (Figure 2). Hydropower accounted for less than 2 per cent. For electricity generated from renewable sources, wind contributed more than half.

In addition to domestic generation capacity, the United Kingdom electricity network also has four interconnectors

FIGURE 1

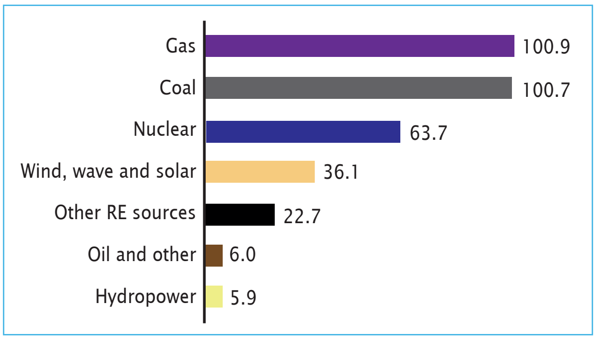
Installed capacity in UK by source (GW)



Source: DUKES[6]

FIGURE 2

Annual electricity generation in UK by source (TWh)



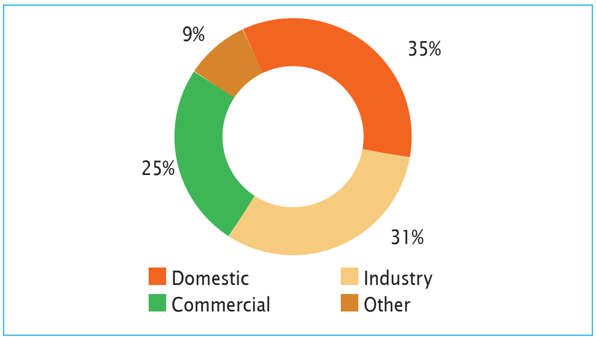
Source: DUKES[7]

totalling 4 GW of capacity connecting the grid with Ireland and mainland Europe.[9] The country was a net importer of electricity in 2014, with net imports contributing 5.7 per cent of the electricity supply.[7]

Final consumption in 2014 was 303.4 TWh with approximately 36 per cent consumed by the residential sector, 31 per cent by the industrial sector and 25 per cent by the commercial sector (Figure 3).

FIGURE 3

2014 electricity consumption by sector (%)



Source: DUKES[6,7]

Although there are many producers operating within the generation sector, it is largely dominated by six companies collectively known as the Big Six: EDF, Centrica (British Gas), E.ON, RWE nPower, Scottish Power and SEE plc. 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 United Kingdom grid. Nine Distribution Network Operators (DNO), operating in 12 separate regions, distribute electricity from the transmission network.

Full competition was introduced into the United Kingdom electricity retail market in 1999.[12] 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). 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.[13]

Electricity costs vary across suppliers and regions. In 2014 the average annual residential rate in the United Kingdom (across all payment types) was approximately GPB 0.158/kWh (US$0.248).[32] According to 2012 data, average electricity prices of the Big Six were:

- British Gas: GBP 0.151/kWh (US$0.240);
- EDF Energy: GBP 0.160/kWh (US$0.254);
- nPower: GBP 0.162.kWh (US$0.257);
- E.ON Energy: GBP 0.148/kWh (US$0.235);
- Scottish Power: GBP 0.168/kWh (US$0.267);
- SSE: GBP 0.155/kWh (US$0.246).[33]

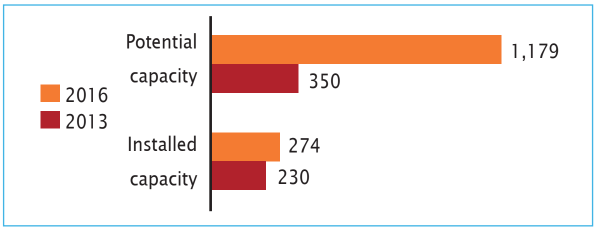
The United Kingdom faces particular challenges to ensure a continuing security of supply, to decarbonize electricity generation and to maintain affordability.[14] Electricity demand is expected to increase due to electrification of end-use sectors such as transport and heat.[15] Further, approximately a fifth of existing plants are set to close over the coming decade and will be replaced by sources which are likely to be increasingly intermittent, such as wind, or inflexible, such as nuclear.[14,15] An analysis by the Committee on Climate Change (CCC) has suggested the need for investment in 30-40 GW of low-carbon capacity between 2020 and 2030, to replace the ageing capacity currently on the system and to meet growing demand.[16] Renewable generation, especially wind, can play a greater role to meet part of the future capacity expansion requirements in the UK power sector. In recent years, investment in wind has made good progress, with the construction of 1.1 GW of onshore capacity and 0.33 GW of offshore capacity in 2013/14, leading to a total installed capacity of 11.1 GW of wind by end of 2014.[8] The Government has introduced renewable electricity policies in order to increase the share of renewable energy (wind, biomass, solar and hydro) in the UK electricity generations (see below).

Small hydropower sector overview and potential

In the United Kingdom small hydropower (SHP) is generally classed as below 10 MW.[30] As of September 2015 there was an estimated installed capacity of 274.2 MW with an estimated additional, financially viable, potential of up to 905 MW, bringing total potential to 1,179 MW.[26,27,31] This would suggest that approximately 23 per cent of SHP potential, below 10 MW, has been developed. It is worth noting, however, that the estimated potential figure is based upon studies with lower limits meaning sites with sufficiently low capacities were not included (see below). In comparison to data from *World Small Hydropower Development Report* (*WSHPDR*) *2013*, installed capacity has increased by approximately 19 per cent while estimated potential has increased by over 236 per cent.[32]

FIGURE 4

SHP capacities 2013-2016 in United Kingdom (MW)



Sources: SISTEch et al.,[26] BHA,[27,31] *WSHPDR 2013*[32]

There is an estimated 340 SHP plants in the United Kingdom with a total capacity of 274.202 MW. Sixty-five of these sites are between 1 MW and 10 MW representing more than 75 per cent of the total installed capacity (Table 1). This represents approximately 6.4 per cent of the total hydropower installed capacity and approximately 0.3 per cent of the country's total installed capacity. Almost all of the country's hydropower plants are located in Scotland and Wales.

TABLE 1

SHP plants in the United Kingdom by capacity (MW)

	1-10 MW	500-999 kW	100-499 kW	50-99 kW	25-49 kW	Less than 25 kW
Number of sites	65	46	128	39	31	31
Installed capacity (MW)	206.85	32.67	30.59	2.69	1.08	0.33

Source: BHA[31]

Due to costs and concerns about its environmental impact, further large-scale development potential is limited. However, there is scope for exploiting the country's remaining SHP resources in a sustainable way. The good quality and most financially viable sites have already been utilized or lie in protected regions of the Scottish highlands and Snowdonia, Wales. The British Hydropower Association's (BHA) England and Wales Hydropower Resource Assessment Report has identified approximately 1,692 potential sites in England and Wales. The total potential identified by this study is between 146 MW and 248 MW. Between 119 MW and 185 MW, or 75 to 80 per cent, are from potential sites located in England and between 59.33 MW and 77.51 MW, or 30 to 40 per cent, from potential sites in the north of England.[26] A separate study of SHP potential modelled 36,252 separate sites that were deemed practically and technically feasible in Scotland. 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 between 100 and 500 kW (537 sites with total potential capacity 150.4 MW).[27] Both studies however, had lower limits in terms of the potential capacity of sites which were included. For the England and Wales study, a lower limit of 25 kW was set for remote sites and for the Scottish 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 modernised to provide generated electricity. With some estimates suggesting there could be 20,000 old water mill sites in England alone there remains significant potential unaccounted for.[33]

Renewable energy policy

The Government has a target of 15 per cent of energy supply from renewable sources by 2020, in order to contribute to the European Union's (EU) overall binding target of 20 per cent of energy consumption from renewable sources by the same year.[17] The Government has indicated that it expects to meet this target with 30 per cent of electricity supplies coming from renewable sources by 2020.[19] Having achieved its own target of 31 per cent by 2013, Scotland has introduced an ambitious renewable energy target of 100 per cent by 2020.[20]

Major polices relating to renewable electricity generation include: feed-in tariffs (FITs), the Renewable Obligation (RO) and Contracts for Difference (CfD). FITs for renewable energy were announced in October 2008 as part of the Energy Act 2008 and came into effect in April 2010. The tariffs apply to electricity generated from plants of no more than 5 MW utilizing hydropower, solar photovoltaic, wind or anaerobic digestion with an eligibility period of 20 years. Micro combined heat and power (CHP) installations of 2 kW or less are also eligible. The FITs cover all energy generated, not just what is fed into the grid. However, electricity that is fed into the grid receives a small additional export tariff of GBP 0.0485 (US$0.077) per kWh as of 1 April 2015.

TABLE 2

Proposed hydropower FITs in the United Kingdom, 1 October 2015 to 31 March 2016

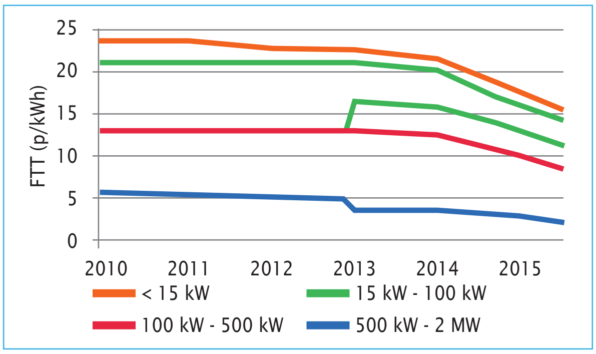
Plant capacity	Rates GBP/kWh (US$/ kWh)
< 15 kW	0.1545 (0.2455)
15 kW-100 kW	0.1443 (0.2292)
100 kW-500 kW	0.1140 (0.1811)
500 kW-2 MW	0.0891 (0.1416)
> 2 MW	0.0243 (0.0386)

Source: Ofgem[38]

As of June 2013 over 400,000 installations were part of the FIT scheme with a total capacity over 2.1 GW.[37] Since their introduction the FITs have been slowly reduced at regular intervals with FITs for hydropower being reduced by an average of 25 per cent while those specifically for plants above 2 MW reduced by almost 50 per cent (Figure 5).

FIGURE 5

FITs for hydropower in the United Kingdom by capacity 2010-2016



Source: Ofgem[38]

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 the 2013/2014 period 62.8 million ROCS were issued by the Government, the highest number on record, with each ROC worth GBP 47.72 (US$75.83). Suppliers in England, Wales and Scotland were required to present 0.206 ROCs per MWh of electricity supplied while suppliers in Northern Ireland required 0.097 ROCS per MWh. All suppliers met their obligations in this period with 60.8 million ROCS presented for compliance and GBP 42.4 million (US$67 million) paid into the buy-out fund. Total supplier obligation was 61.9 million ROCs meaning 98.2 per cent of obligations were complied with via ROCs, the highest proportion since the introduction of the scheme.[34] The RO scheme is currently being phased out in favour of a new scheme, Contracts for Difference (CfD) and will close to new generating capacity in 2017.

The CfD scheme was introduced in 2013 and constitutes a contract between a low carbon electricity generator and the government-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.[35]

Legislation on small hydropower

All hydropower projects must obtain three permissions prior to construction and operation: an environmental license 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. FITs for hydropower from 1 October 2015 to 31 March 2016 are given in Table 1. FITs are available only for plants with an installed capacity less than 5 MW (see below). As of 2015 there were 421 accredited hydropower plants on the Central FIT Register with a combined total capacity of 43 MW.[24]

Barriers to small hydropower development

Investment in new SHP plants is limited despite the renewable policies. The FITs had only had a small impact on hydropower with only 2 per cent of the total capacity of plants registered for FITs coming from hydropower. Lowering of the FIT tariffs may further deter potential investors.

In addition, investors and operators must consider environmental issues including additional features which may impact costs.[28] Developers must not only have the initial financial outlay for the build, but also for feasibility studies on the economic viability and environmental impact of a potential site and detailed analysis and expensive hardware to prevent adverse effects on fishing. They also have to counter a range of perceived conflicts with river-based leisure interests and prove that there will be no impacts to the river bed, river banks, flora and fauna, land drainage or the ability to remove flood waters.[29]

4.3 Southern Europe

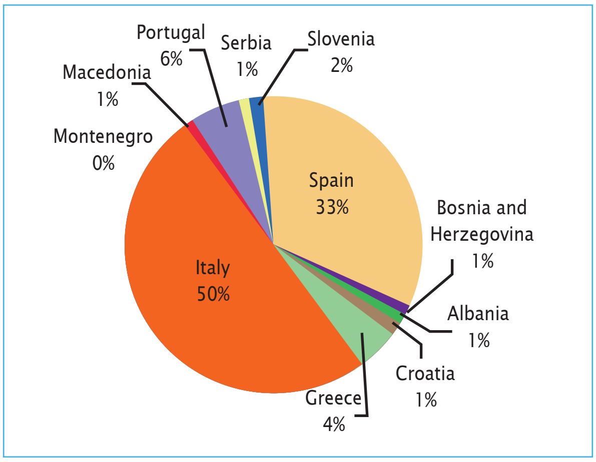
Paulo Alexandre Diogo, New University of Lisbon

Introduction to the region

Southern Europe comprises 16 countries and territories. This report covers 11 of them that use small hydropower (SHP): Albania, Bosnia and Herzegovina, Croatia, Greece, Italy, The Former Yugoslav Republic of Macedonia (Macedonia), Montenegro, Portugal, Serbia, Slovenia and Spain. The overview of these countries is given in Table 1.

FIGURE 1

Share of regional installed capacity of SHP by country



Source: *WSHPDR 2016*[1]

Six of these countries (Croatia, Greece, Italy, Portugal, Slovenia and Spain) are European Union (EU) member states. Four other countries (Albania, Macedonia, Montenegro and Serbia) are recognized candidates for EU membership and Bosnia and Herzegovina is a potential candidate. As a result, all countries of the region have their national policies aligned in accordance with the EU initiative on renewable energy.

Climate and resource endowments vary from country to country. However, most countries experience the same regional energy-related challenges, namely heavy dependence on imported fossil fuels, underdeveloped grid infrastructure and climate change causing temperature increase and desertification. Due to the region's high dependence on imported energy, it is exposed to geopolitical tensions and commodity price volatility. In order to strengthen their energy security, the countries aim to reduce the share of fossil fuels in electricity production and diversify energy sources, in particular, through development of domestic renewable energy. However, the economic downturn experienced by the region since 2008 has heavily affected national economies and drove down investments in the energy sector, including renewable energy sources.

The main renewable energy sources developed in the region are hydropower, wind power and solar power. With the long history of hydropower exploitation and the total

TABLE 1

Overview of countries in Southern Europe (+/– % change from 2013)

Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Albania	2.82 (-6%)	44 (-8pp)	100	1,823 (+17%)	4,724 (-38%)	1,725 (+18%)	4,724 (-11%)
Bosnia and Herzegovina	3.79 (-2%)	60	100	3,989 (-7%)	15,030 (+7%)	2,085 (-12%)	5,821 (-6%)
Croatia	4.24 (-5%)	41 (-1pp)	100	4,017 (+1%)	13,431 (-8%)	2,141 (+1%)	8,106 (+6)
Greece	10.90 (+1%)	22 (-)	100	19,604 (+27%)	50,300 (-3%)	3,241 (+7%)	3,800 (-37%)
Italy	61.34 (+0.1%)	31 (-1pp)	100	121,762 (+10%)	269,148 (-7%)	21,979 (+24%)	59,575 (+30%)
Macedonia, FYR	2.08 (+1%)	43	100	2,011 (+33%)	4,980 (-22%)	663 (+26%)	1,200 (-45%)
Montenegro	0.63 (-2%)	36	100	867 (0%)	3,105 (+16%)	657 (-0.2%)	1,686 (-39%)
Portugal	10.37 (-4%)	37 (-2pp)	100	17,404 (-3%)	48,999 (-9%)	5,335 (+7%)	16,412 (+1%)
Serbia	7.13 (-2%)	45 (-3pp)	100	8,350 (-0.1%)	36,832 (+3%)	2,800 (-0.7%)	11,472 (-8%)
Slovenia	2.06 (+3%)	50 (0pp)	100	3,453 (+13%)	17,437 (+34%)	1,295 (+53%)	6,366 (+81%)
Spain	46.4 (-1%)	21	100	108,299 (+14%)	268,057 (-3%)	20,778 (+12%)	31,396 (+37%)
Total	**151.76 (-0.9%)**	—	**100**	**291,576 (+11%)**	**732,043 (-4%)**	**62,699 (+14%)**	**150,558 (+15%)**

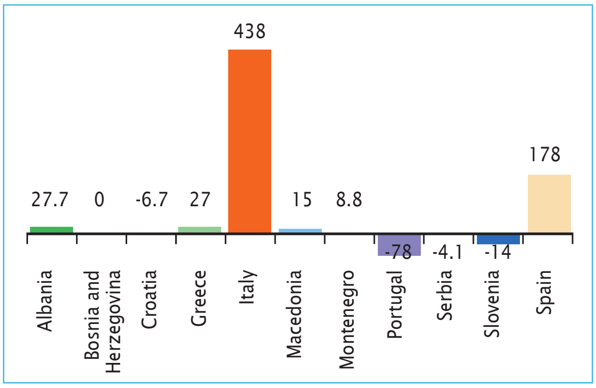
Sources: Various[1,3,4,5,6,7]

Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

installed capacity of approximately 61 GW, hydropower remains critical for Southern Europe. Thus, Italy is the fourth-largest producer of electricity from hydropower in Europe, whereas Croatia and Macedonia produce more than half of their electricity from hydropower, and Albania depends completely on hydropower. The potential of hydropower remains largely untapped in the region, especially in the Balkan countries. High solar radiation also creates very good potential for solar energy development, with Italy and Spain being the second and third major solar power contributors in the EU.[8]

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for Southern Europe



Sources: *WSHPDR 2013*,[2] *WSHPDR 2016* [1]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.

Small hydropower definition

SHP is defined as up to 10 MW by most countries of the region, except Albania and Greece, which have an upper limit of 15 MW, and Serbia, with 30 MW (Table 2). Serbia extended its definition of SHP from 10 MW up to 30 MW in January 2013.

TABLE 2

Classification of small hydropower in Southern Europe

Country	Small (MW)
Albania	Up to 15
Bosnia and Herzegovina	Up to 10
Croatia	Up to 10
Greece	Up to 15
Italy	Up to 10
Macedonia, FYR	Up to 10
Montenegro	Up to 10
Portugal	Up to 10
Serbia	Up to 30
Slovenia	Up to 10
Spain	Up to 10

Source: *WSHPDR 2016*[1]

Regional SHP overview and renewable energy policy

As of 2016, the region's total installed SHP capacity amounts to 6,286 MW, with the countries' installed SHP capacities ranging from 18 MW in Montenegro to 3,173 MW in Italy (Table 3). Italy is also the regional leader in terms of SHP potential. The total SHP potential of Southern Europe is at least 16 GW, with a significant number of projects awaiting implementation. However, the exact regional potential is unknown because many countries do not have accurate data or have never performed any studies of their SHP potential.

TABLE 3

Small hydropower* in Southern Europe (+/– % change from 2013)

Country	Installed capacity (MW)	Potential capacity (MW)
Albania	65.1 (+74%)	1,963 (-)
Bosnia and Herzegovina	36.0 (0%)	1,000 (0%)
Croatia	32.9 (-17%)	100 (+150%)
Greece	223.0 (+14%)	2,000 (0%)
Italy	3,173.0 (+16%)	7,073 (+0.1%)
Macedonia, FYR	60.0 (+33%)	260 (+4%)
Montenegro	17.8 (+98%)	97.5 (-59%)
Portugal	372.0 (-17%)	750 (0%)
Serbia	45.5 (-8%)	409 (0%)
Slovenia	157.0 (+34%)	475 (+147%)
Spain	2,104.0 (+9%)	2,185 (0%)
Total	**6,286 (+11%)**	**16,313 (+15%)**

Sources: *WSHPDR 2013*,[2] *WSHPDR 2016*[1]
Notes:
a. The comparison is between data *WSHPDR 2013* and *WSHPDR 2016*. A large difference or a negative change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.
b. Data is for up to 10 MW with the exception of Greece which is up to 15 MW.

In Southern Europe, SHP, with its significant untapped potential, plays an increasingly important role in the growth of renewable energy, which is one of the main priorities for the countries' energy development in accordance with EU policies. All countries in Southern Europe that are members of the EU follow EU Directive 2009/28/CE, which sets the target of a 20 per cent share of renewable energy sources in the EU gross final energy consumption to be achieved by 2020. The target distribution among the countries of Southern Europe is as follows: Croatia, 20 per cent; Greece, 18 per cent; Italy, 17 per cent; Portugal, 31 per cent; Slovenia, 25 per cent; Spain, 20 per cent. According to the progress reports submitted by the countries in 2013, the following percentages had already been achieved: Croatia, 18 per cent; Greece, 15 per cent; Italy, 16.7 per cent; Portugal, 25.7 per cent; Slovenia, 21.5 per cent; and Spain, 15.4 per cent.[9]

As candidates for EU membership, the other five countries aim to align their energy policies with the EU and have implemented Directive 2009/28/CE as well. Their shares were calculated based on the same methodology for the EU member states and reflect an equal level of ambition. The national targets set for them are as follows: Albania, 38 per cent; Bosnia and Herzegovina, 40 per cent; Macedonia, 28 per cent; Moldova, 17 per cent; Montenegro, 33 per cent; and Serbia, 27 per cent.[7]

In order to promote the development of renewable energy, all countries of the region have implemented economic incentives, which have also driven the growth of SHP. Thus, suppliers of electricity from renewable sources have received a range of benefits, which include feed-in tariffs (FIT), priority connection to the grid, guaranteed purchase of electricity, preferential access to the network and subsidies. However, in Portugal, the incentives are considered insufficient because of a reduction of the FIT in 2005, whereas Spain in 2012 temporarily suspended FIT pre-allocation and removed economic incentives for new power generation, including renewable energy sources, because of the tariff deficit caused by these incentives.

Barriers to small hydropower development

Although Southern Europe has a significant SHP potential, its further development is hampered by a number of barriers.

One of the most common barriers is the long and complicated authorization and licensing process—a problem reported to be experienced by developers in Greece, Italy, Montenegro, Portugal, Serbia and Spain. Other institutional and regulatory barriers include corruption, disagreement between local and national regulations and institutions. In Bosnia and Herzegovina frequent changes in regulations have caused problems for developers, and other regulatory issues are mentioned as relevant to Albania, Greece, Macedonia, Montenegro and Portugal.

Bosnia and Herzegovina, Croatia, Slovenia, Greece and Montenegro have issues related to water management, with Greece and Montenegro lacking strategic water management documents. In Croatia and Serbia, finding the required initial capital investment can be problematic.

Moreover, missing or weak distribution networks complicate SHP development in Macedonia and Montenegro as their sites with the highest SHP potential are located in remote areas. Development of potential SHP sites is also limited in Croatia due to legal protection of the country's cultural heritage and landscapes. Italy experiences pressure on the part of social movements that do not approve of hydropower plants, whereas in Serbia there is a generally low awareness of the advantages of SHP among the public as well as professionals. In Albania, power losses reaching above 30 per cent is a significant problem.

Finally, a number of countries, including Croatia, Macedonia, Serbia, Slovenia and Spain, lack accurate hydrological data, which hinders further SHP development.

4.3.1 Albania

Arian Hoxha

Key facts

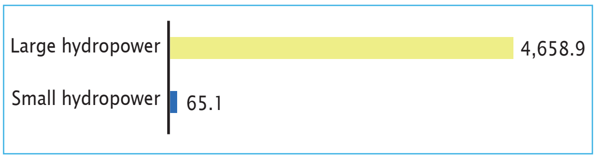
Population	2,894,475[1]
Area	28,748 km[2]
Climate	Albania is situated in a transition zone between the Mediterranean climate and the moderate continental climate. Winters are cool, cloudy and wet and summers are hot, clear and dry on the coastal plain. In the mountainous interior part of the country, rainfall in summer is more common and winters are cooler. The average annual temperature is 15°C, the minimum average temperature 1.6°C and the maximum average temperature 20.9°C.[2]
Topography	Mostly mountainous terrain with small plains along the coast and river valleys. The highest peak is Mount Korab at 2,751 metres above sea level, situated in the east, at the border with Macedonia.[2]
Rain pattern	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 rainfall occurs from November to March.[2]
General dissipation of rivers and other water sources	Albania has 11 major rivers with their 150 tributaries. The longest river in Albania is the Seman, which is 281 km long and divides into the Devoll and Osum. The River Vjosa, 272 km long and, originating from Smolika mountain, is the most torrential in Albania.[11] The average altitude of the hydrographical territory is about 700 metres above sea level. The total average flow of the rivers is approximately 1,245 m^3/sec.[3]

Electricity sector overview

The main power producer is the Albanian Power Corporation S.A (KESH); it is 100 per cent owned by the State. The total installed capacity in 2014 was 1,823 MW, with the installed capacity of hydropower at 1,725 MW. The thermal power plant (TPP) in Vlora has an installed capacity of 98 MW.[10] However, as of 2014, the Vlora TPP was not used due to issues with its cooling system.[16] The total generated electricity in 2014 was 4,724 GWh (Figure 1), with 3,408 GWh from KESH and 1,318 GWh from other producers.[12]

FIGURE 1

Electricity generation by sources in Albania (GWh)



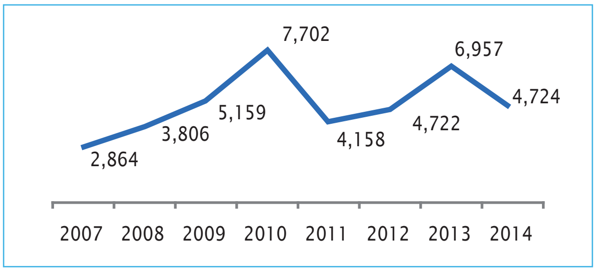
Source: Ministry of Energy and Industry[10]

It should be noted that the significant difference between the highest and lowest electricity generated volumes due to changing water flows highlights the risk of the power security and stability (Figure 2). Electricity consumption is steadily increasing, with 7,793 GWh reached in 2014 (Figure 3). In 2014 2,814 GWh of electricity was imported.[16]

The thermal power plant at Vlora was meant to start operating in 2011, but due to technical problems in 2014 it was still idle. The KESH S.A was in the process of resolving all related legal disputes with the contractor.

FIGURE 2

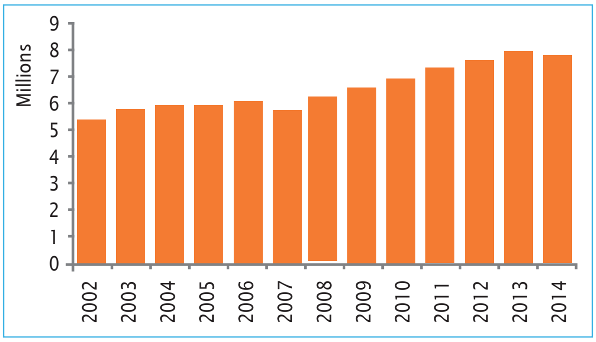
Generation of electricity in Albania 2007-2014 (GWh)



Source: Energy Regulatory Body[12]

FIGURE 3

Electricity consumption in Albania 2002-2014 (MWh)



Source: Energy Regulatory Body[12]

Meanwhile a pre-feasibility study for using Liquid Natural Gas (LNG) as a primary source for energy instead of oil was under preparation.[20]

The transmission system of Albania comprises 400 kV, 220 kV, 110 kV lines and interconnected substations that serve transmission and international interconnectivity. The latter includes: 220 kV lines from Albania to Kosovo and from Albania to Montenegro, 400 kV lines from Albania to Greece and from Albania to Montenegro, 150 kV lines from Albania to Greece. The public entity responsible is the Transmission System Operator.

The Distribution System Operator (OSHEE) is now a 100-per-cent public-owned company. Recent initiatives and reforms have achieved a positive impact on the reduction of electricity losses (both technical and non-technical) and increased the collection rate of unpaid bills. The level of electricity losses was reduced from 45 per cent in 2013 to 37.8 per cent in 2014. The reduction of the losses in the distribution grid has continuously increased in the first months of 2015. The losses in January, February and March 2014 were 47 per cent, 42 per cent and 42.8 per cent, respectively, whereas in 2015 they were 36.6 per cent, 31.8 per cent and 33.4 per cent, respectively. The annual collection improved from ALL 38.5 billion (US$302.65 million) in 2013 to ALL 49.1 billion (US$386 million) in 2014 (Table 1). The first months of 2015 also recorded a significant improvement in collection compared with the revised targets.[12]

TABLE 1

Electricity tariffs in Albania for 2015

Activity		Approved tariff (ALL (US$) per kWh)
Production KESH		1.45 (~ 0.01)
Wholesale public supplier		3.0 (~0.02)
Transmission OST		0.65 (~0.005)
Users of distribution grid 35 kV		1.5 (~0.01)
Users of distribution grid		4.79 (~0.038)
Private small and large HPP		7.636 (~0.06)
Distribution retail prices	**Off-peak**	**Peak**
Consumers 35 kV	9.5 (~ 0.075)	10.93 (~ 0.086)
Consumers 20/10/6 kV	11 (~ 0.086)	12.65 (~ 0.1)
Consumers 0.4 kV	14 (~ 0.11)	16.1 (~ 0.127)
Households	9.5 (~ 0.075)	9.5 (~ 0.075)

Source: Energy Regulatory Body[5]

There have been a number of changes in the sector, which relate to an overall reform process across all areas including legislative and strategic aspects. The country's generating capacity still remains insufficient for meeting its demand. However, the overall production has increased. The transmission system should soon benefit from the investment projects including the 400 kV interconnection lines with Kosovo in addition to the South Ring line, which is being finalized. The key event in the distribution sector was the resolution of the dispute between the formerly licensed operator and the Government of Albania.

Until 2015, the electricity market was based on the Transitory Market Model established by the Government Decree No. 539 dated 12 August 2004.[21] The decree defined the actors, roles and responsibilities for addressing all related issues and challenges and also ensuring cooperation in terms of legislation compatibility with the European Union directives. On 30 April 2015 the Albanian Parliament adopted the new Law on Energy Sector compliant with the Third Energy Package. The law has fully transposed Directive 2009/72/EC. It includes:

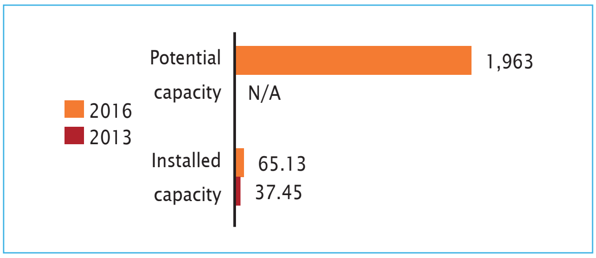
- Liberalization, organization, participation and functioning of a competitive electricity market;
- Authorizations and licensing procedures in the electricity sector;
- Consumer protection, security of supply and competitive structures in place within the sector;
- Integration of the Albanian electricity market into the regional and European electricity market.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) used in Albania is up to 15 MW.[22] Installed capacity of SHP plants up to 10 MW in Albania is 65.13 MW while the potential is estimated to be 1,963 MW, indicating that nearly 3.5 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has almost doubled (Figure 4).[14]

FIGURE 4

Small hydropower capacities 2013-2016 in Albania (MW)



Due to its topography, Albania is quite rich in rivers, with more than 150 rivers and torrents forming eight main big rivers. They have a south-east to north-west flow, mainly oriented towards the Adriatic coast. The most important rivers are the Drin (340 m^3/sec), Vjosa (210 m^3/sec), Seman (101 m^3/sec), Mat (74 m^3/sec), and Shkumbin (60 m^3/sec) revers. Although they have small flows, their considerable inclination makes these rivers important for hydropower development. Consequently, Albania is seen as a country rich in water reserves and its hydropower potential can play an important role in the development of the country. Considering the current power supply situation as well as the potential demand for power, the Government has set the development of the energy sector among its priorities, focusing on the development of renewable energy resources and, in particular, hydropower plants. There is a large hydropower potential and currently only 35.4 per cent of it is being used. The total hydropower reserves could enable the installation of a 4,500-MW power network and its annual electricity power production could reach up to 16 TWh. Based on studies carried out by international consultants, the main potential areas for installation of hydropower plants are the Drin River, the Osum River, the Vjosa River and the Erzen River.[3]

There are no new SHP projects planned or carried out currently.

Legislation on small hydropower

Established by the Power Sector Law (Law No. 9072), the Energy Regulatory Body (ERE) has the authority to regulate electricity pricing for existing hydropower stations under 10 MW and for new installations of up to 15 MW, and only these SHP installations may receive feed-in tariffs with power purchase agreements with the ERE.[17]

Moreover, the ERE is responsible for granting licenses to power producers with separate licenses for generation, transmission and distribution of electricity. Under its Rules of Practice and Procedure (Decision No. 21 dated 18 March 2009), the ERE guarantees equal treatment in issuing licenses and resolving disputes between parties.[5] More specifically, under the Rules and Procedures on Certification of Electricity from renewable sources, the ERE has outlined the procedures for generators to apply for green certificates and approval of project implementation.

The criteria for authorization of new electricity generating capacity without concessions are duly transposed by the Power Sector Law, whereas tendering for new capacity is not treated in the Power Sector Law but indirectly governed by the Law on Concessions. This has helped to increase the participation of independent power producers (IPP) in the development of SHP installations or the rehabilitation of existing mini grid systems, such as the successfully implemented New Arras SHP plant.[18]

In addition to the new Power Sector Law of 2015, the Government is drafting new laws on renewable energy and on energy efficiency, as well as regulatory acts of those laws, which are likely to further liberalize the sector. Meanwhile the Government has removed the VAT on imported machinery, which will facilitate foreign investment and SHP development.[19]

Renewable energy policy

Under Directive 2009/28/EC, Albania has committed to a binding 38 per cent target of energy from renewable sources in gross final energy consumption in 2020, compared with 31.2 per cent in 2009. The network operators have to increase transparency regarding connection and access to the grids. In 2015 the Energy Regulatory Body was working on the preparation of a system that would certify renewable sources of energy based on guarantees of the origin. Also the Ministry of Energy and Industry is finalizing the Energy Efficiency Law to be sent to the Parliament for approval. It would be essential for further development of the legislative framework and for the implementation of corresponding measures foreseen for the achievement of energy efficiency targets.

Barriers to small hydropower development

While SHP installed capacity has risen considerably in recent years, the progress of SHP development in Albania is slower than expected due to the delay in the approval of the law on Renewable Energy which will establish mechanisms of support and incentive schemes for developers. The main obstacles to SHP development are related, but not limited to the lack of financing.

4.3.2 Bosnia and Herzegovina

Armin Hadzialic, Higracon d.o.o. Sarajevo

Key facts

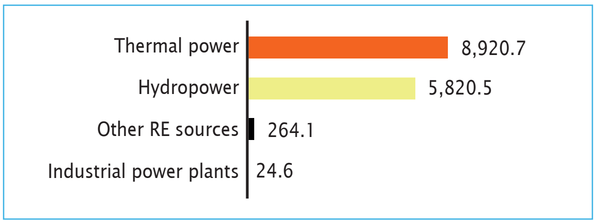
Population	3,791,662[1]
Area	51,209 km²
Climate	Bosnia and Herzegovina has three climatic zones: a moderate continental climate in the north, a mountainous climate in the centre and a Mediterranean climate in the south-west. Overall mean annual temperatures are between 9.5°C and 14.6°C. Mean temperatures in January are around 0°C while in July the mean temperatures are between 18.7°C and 22.6°C. Absolute minimum temperatures can dip below –27°C in the mountainous regions; absolute maximum temperatures can reach 45°C.[2]
Topography	The territory of Bosnia and Herzegovina can be divided into three geographic zones: high plains and plateaus along the northern border with Croatia, low mountains in the centre and the higher Dinaric Alps covering the rest of the country. The highest mountain is Maglic at 2,386 metres above sea level. Approximately 50 per cent of the country is covered by forests.[3]
Rain pattern	In the northern continental climate zone average annual precipitation ranges from 700 mm in the east to 1,300 mm in the west. In the southern Mediterranean zone annual average precipitation ranges from 1,000 mm to 1,800 mm. The highest levels of precipitation occur in the colder part of the year—between December and February, while between June and August the precipitation is relatively low. During this time of year drought periods are possible.[1]
General dissipation of rivers and other water sources	Rivers and lakes of Bosnia and Herzegovina are part of the hydrographical basin of the Black Sea and the Adriatic Sea. The Sava is the most prominent river that flows into the Black Sea and runs 345 km in Bosnia and Herzegovina, along the northern border with Croatia. All the major rivers in Bosnia and Herzegovina flow into the Sava River, which is the largest tributary of the Danube: the Una, the Vrbas, the Bosna and the Drina Rivers. The only river that flows into the Adriatic Sea is the Neretva in Herzegovina. In Herzegovina there is a massive karst area (more than 4,000 m²) below which flow a number of underground rivers and streams.[4]

Electricity sector overview

In 2014, total electricity generation of Bosnia and Herzegovina was 15,030 GWh. Approximately 59 per cent came from thermal power plants, 39 per cent from hydropower and less than 2 per cent from other renewable sources and industrial power plants combined (Figure 1).[5]

FIGURE 1

Annual electricity generation in Bosnia and Herzegovina by source (GWh)

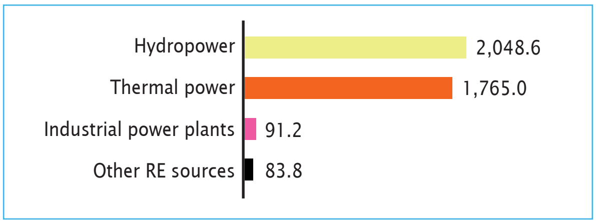


Source: State Electricity Regulatory Commission[5]

Total installed capacity in 2014 was 3,988.58 MW, with 2,048.6 MW (51.3 per cent) from large hydropower, 1,765 MW (44.3 per cent) from thermal power plants, 91.23 MW (2.3 per cent) from industrial power plants and 83.75 MW (2.1 per cent) from small hydropower (SHP), wind and solar power plants combined (Figure 2).

FIGURE 2

Installed electricity capacity in Bosnia and Herzegovina by source (MW)



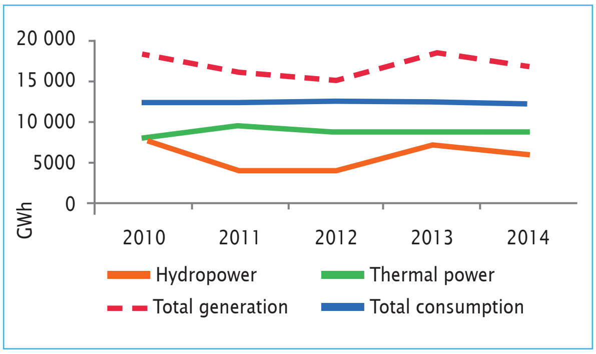
Source: State Electricity Regulatory Commission[5]

Unfavourable hydrological conditions in 2014 reduced the amount of electricity generated by hydropower plants by approximately 18 per cent compared to 2013. Figure 3 shows variations in hydropower generation and its relationship to the overall electricity generation mix.[5] Nonetheless, despite annual variations, the country is a net exporter of electricity with consumption remaining significantly below generation since 2010. Overall consumption in 2014 was 12,209.72 GWh and the country has an electrification rate of 100 per cent.

The electricity market in Bosnia and Herzegovina is structurally underdeveloped despite its potential and the commercial activities of the industry. Due to the country's unique political structure, there are multiple energy regulatory bodies, which makes their work complicated and less efficient. As established by the 1995 Dayton Agreement, there is a national government, as well as second-tier governments of the Federation of Bosnia and Herzegovina (FBiH) and the Republika Srpska (RS). Following this political structure, the regulatory structure includes three regulators—one at the national level and two entity-level regulators.

FIGURE 3

Annual generation in Bosnia and Herzegovina 2010-2014 (GWh)



Source: State Electricity Regulatory Commission[5]

At the national level, the Ministry of Foreign Trade and Economic Relations of Bosnia and Herzegovina (MOFTER) has primary responsibility over the energy sector. The State Electricity Regulatory Commission (SERC) is in charge of regulatory implementation with regards to electricity transmission, transmission system operation and international trade.

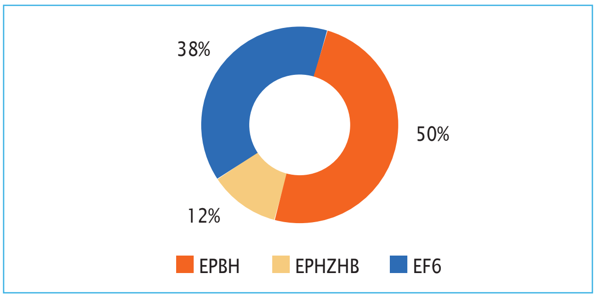
At the entity level, the energy sector is regulated by the Ministry of Energy, Mining and Industry of the Federation of Bosnia and Herzegovina (FMEMI); and the Ministry of Industry, Energy and Mining of the Republika Srpska (MIEMRS). The Federation of Bosnia and Herzegovina Electricity Regulatory Commission (FERK) and the Republika Srpska Energy Regulatory Commission (RERS) implement regulation of electricity generation, distribution and supply within each entity respectively.

The participants of the electricity market are: the Independent System Operator in Bosnia and Herzegovina (ISO BiH) (which began operations in July 2005), the transmission company, Elektroprenos Bosne I Hercegovine(which began operations in February 2006), three separate vertically integrated utilities engaged in generation, distribution and supply (each of which are entity-owned), traders, and eligible customers. The three s utilities are Elektroprivreda BIH Sarajevo (EP BIH), Elektroprivreda HZHB Mostar (EP HZHB) and Elektroprivreda RS Trebinje (ERS). They operate in their regions, while in the Brcko District distribution and supply are carried out by a separate entity (Komunalno Brcko) and owned by the local government. In 2014 EP BIH contributed approximately 50 per cent of the overall electricity generation, ERS 38 per cent and EP HZHB 12 per cent (Figure 4).[5]

The transmission network in Bosnia and Herzegovina consists of 110 kV (cable), 110 kV, 220 kV and 400 kV facilities. The total number of overhead lines is 297, with an interconnection number of 32 and a length of 6,341.48 km. The total number of substations is 145 + 5 (MV), with installed power (MVA) of 12,387.5 + 189.5 (MV), number of transformers 255 + 33 (MV) and transformers installed power (MVA) of 12,387.5 + 189.5 (MV).[7]

FIGURE 4

Annual generation in Bosnia and Herzegovina by generation company



Source: State Electricity Regulatory Commission[5]

Total price for electricity covers: the cost of electricity production and purchase of electricity from renewable energy sources, the supplier's service cost, and the fee for renewable energy sources, which was introduced in accordance with the Regulation of the Government of the Federation of Bosnia and Herzegovina on Renewable Energy Sources and Cogeneration. According to this regulation, each supplier is obliged to submit an invoice to a customer highlighting the amount of total compensation for the promotion of renewable energy sources.

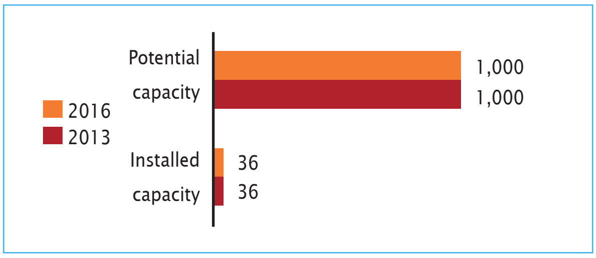
Current winter tariffs (October – April) for unqualified (tariff) customers are approximately EUR 0.640/kWh (US$0.852). Summer tariffs (April – October) are approximately EUR 0.492/kWh (US$0.655).[8] For electricity generation from renewable sources (and for efficient cogeneration) suppliers receive a number of benefits including: priority connection to the grid, preferential access to the network (dispatch), compulsory purchase of electricity, a guaranteed repurchase price (feed-in tariff) and the right to a premium for the consumption of electricity for their own use or sold on the market.[9]

Small hydropower sector overview and potential

SHP is defined as less than 10 MW with subcategories for mini-hydropower (less than 1 MW) and micro-hydropower (less than 100 kW).[12]

The total installed capacity of SHP plants is 36 MW with a total potential capacity of 1,000 MW. This indicates that approximately 3.6 per cent of SHP potential in the country has currently been developed.[13] This data has remained unchanged since *World Small Hydropower Development Report* (*WSHPDR*) *2013* (Figure 5).[14]

FIGURE 5
Small hydropower capacities 2013-2016 in Bosnia and Herzegovina (MW)



77

Significant activity in the SHP industry began when EP BIH launched a study of hydropower potential on medium and small rivers. Based on this study a public call for concessions was announced between 2005 and 2006 with over 70 concessions for SHP awarded. In the RS, a 1980 study of the hydropower potential on a tributary of the Drina River was the basis for awarding 100 concessions for SHP in 2006. Currently there are 25 operational SHP plants, 10 plants are under construction and a further 135 are in the pre-approval stage.[10]

SHP accounts for approximately 1.8 per cent of total hydropower capacity and less than 1 per cent of the country's total installed capacity.[5] The country's gross theoretical hydropower potential is estimated to be 8,000 MW while the technically feasible potential is 6,800 MW and the economically feasible potential is 5,800 MW. Thus SHP potential is between 12.5 and 17.2 per cent of total hydropower potential.[10]

Electricity from renewable sources, including SHP plants, is mostly purchased by domestic energy companies. They buy electricity at much lower prices than is guaranteed with the difference paid by citizens and other consumers. In the Federation of Bosnia and Herzegovina this amounts to almost half the price and in the Republika Srpska to approximately two-thirds. This is funded by the Fund for Compensation for Renewable Sources, which is sourced from citizens and other electricity consumers. The fee is charged with each electricity bill and, depending on the energy company citizens purchase their electricity from, ranges from KM 0.29 (US$0.197) to KM 0.34 (US$0.231) per month.

In addition to the higher electricity prices, investment in SHP plants is also more cost-effective in the Republika Srpska due to the purchase guarantees lasting 15 years, as opposed to only 12 years in the Federation of Bosnia and Herzegovina. However, even in the period when electricity producers have the right to incentives, price adjustments can occur which are often detrimental to producers. Concessions are issued for a period of 30 years with the possibility of extension; and if not extended, the SHP plants are returned to state ownership. The guaranteed price for energy produced by SHP is approximately EUR 0.06/kWh (US$0.08).

Renewable energy policy

In accordance with the Energy Community Agreement, the Energy Community Ministerial Council adopted an implementation plan for Directive 2009/28/EC on promotion of the use of electricity from renewable sources in 2012. The binding target for Bosnia and Herzegovina is 40 per cent of renewable energy consumption by 2020. To achieve this, the Governments of both the Federation of Bosnia and Herzegovina and the Republika Srpska adopted plans in 2014 to encourage production from renewable energy sources.[15] On the basis of laws adopted for efficient cogeneration and the development of renewable energy sources, both entities also developed and adopted relevant by-laws.

There is still no comprehensive countrywide scheme for promotion and development of the renewable energy sector. Bosnia and Herzegovina continues to operate without a national renewable energy action plan, as required by the Energy Community Treaty and there are no competencies laid down in the relevant legislative framework. Energy laws to enforce such a plan (and the public responsibilities for ensuring that the plan is devised in such a way that the national renewable energy target is reflected in the laws) are unclear. At the same time, the improved legislative framework at the entity level, along with the incentives introduced, has resulted in ongoing promotion of renewable energy sources. In the Federation of Bosnia and Herzegovina the 40 per cent target of total generation from renewable energy has effectively been achieved, which may lead to stagnation of the sector. A smaller number of electricity generating facilities powered by renewable energy sources have been developed in the Republika Srpska, which may enable more development within the region.[11]

Barriers to small hydropower development

Hydropower potential, especially SHP potential, is not sufficiently exploited in Bosnia and Herzegovina. One of the most important factors in the lack of development is the discrepancy between regulations at the entity level and the local community or municipality levels. This means that obtaining the necessary permits may take anywhere from 18 to 36 months. Another concern is the malleability of policy for renewable energy: during construction of projects the law is liable to change with a potentially negative impact on owners and/or investors.

Potential investors may face the possibility for favouritism and corruption which can occur at any step in the construction of SHP plants, from the application for the concession and obtaining permits to the approval of connection to the electricity grid.[6]

In general, the existing model for transmission has never truly been unbundled and independent and the electricity market would benefit from being opened up in real terms, including between the entities. This would require a coordinated process for further liberalization of the supply chains and full recovery of costs, together with creation of a system for the protection of socially vulnerable customers outside price regulation.[6]

4.3.3 Croatia

Marcis Galauska and Nathan Stedman, International Center on Small Hydro Power

Key facts

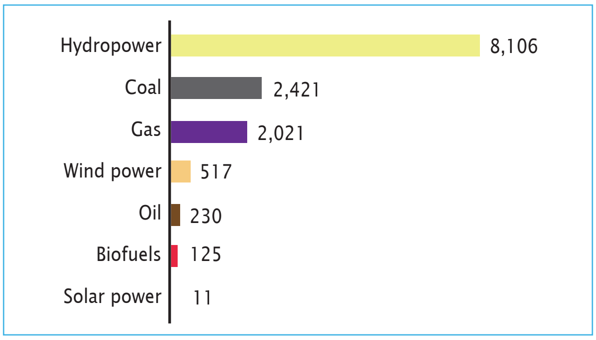
Population	4,238,389[1]
Area	56,594 km[2]
Climate	Mediterranean and continental; continental climate predominant with hot summers and cold winters; mild winters, dry summers along coast. Average temperatures are approximately 25°C during summer and 8°C during winter.[3]
Topography	The country's topography is diverse and includes flat plains along the Hungarian border and low mountains and highlands near the Adriatic coast. The territory can be divided into three geographic zones: the Pannonian and Peri-Pannonian Plains in the east and north-west, the hills and mountains in the centre and the Adriatic coast.[2]
Rain pattern	Precipitation varies across the country. The Adriatic coast enjoys abundant rainfall of 1,000-1,500 mm per year with autumn and winter being particularly rainy. However, some areas in the bays and along the coast are protected by the islands and receive about 800 mm of rain per year. Summers tend to be dry and sunny along the coast, with occasional rain or thunderstorms. Only in the northernmost zone the rains are quite frequent and abundant even in the months of July and August. In the interior parts of the country precipitation is frequent ranging from 700 to 860 mm per year.[3]
General dissipation of rivers and other water sources	About 62 per cent of the territory is covered by the branching river network that belongs to the Black Sea catchment basin. The longest Croatian rivers, the River Sava (562 km) and the River Drava (505 km) also belong to this catchment basin, as does the Danube, into which they both flow. These three rivers to a large extent form the natural borders of the country.[4]

Electricity sector overview

In 2013, overall domestic electricity supply was 17,921 GWh, electricity generation was 13,431 GWh, including hydropower (60 per cent), coal (18 per cent), gas (15 per cent), wind (4 per cent), oil (2 per cent) and biofuels (1 per cent), while solar PV produced less than 0.1 per cent; exports were 6,770 GWh and imports 11,260 GWh (Figure 1 and Figure 2).[5] Installed capacity was 4,017 MW and the electrification rate 100 per cent.

FIGURE 1

Electricity generation by source in Croatia (GWh)

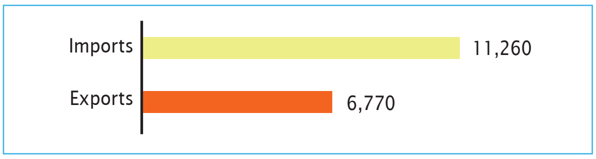


Source: IEA[5]

Croatia has four major hydroelectric plants in two main areas of the country: near the Slovenian-Hungarian border and along the Adriatic coastline. The Varazdin hydropower plant is located near the Slovenian-Hungarian border, and the three hydropower plants along the Adriatic coastline are at Senj, Obrovac and Zakucac. All of these are owned and operated by the national electricity company, Hrvatska Elektroprivreda (HEP).

FIGURE 2

Electricity supply (GWh)



Source: IEA[5]

The 486 MW Zakucac hydroelectric plant, the largest power plant in Croatia, is scheduled for renovation to improve its operability. A tender has been announced for the new 68.5 MW Ombla hydroelectric plant proposed for a site on the Rijeka Dubrovacka River. Two additional hydropower plants have also been proposed, the 106-MW Virje plant and the 42 MW Lesce plant.

The Croatian electric power transmission system is owned and operated by HEP. The electricity distribution grid has three different voltages; there are 903 kilometres of 400 kV lines, 1,224 kilometres of 220 kV lines, and 4,760 kilometres of 110 kV lines. There are also five 400 kV substations, fifteen 220/110 kV substations and 140/110 kV substations.[6]

Although the Croatian electricity market is formally open, the market activities of generation, supply and trade are mainly carried out by state-owned companies. There are 28 companies active in the generation sector. Although the majority of these (approximately 80 per cent) are privately owned, their market share is dwarfed by the generation capacities of state-owned companies, which dominate the sector. There are 18 companies that cover electricity supply. Three of these companies are state-owned and hold the majority of the market share. In 2014, companies forming part of the state-owned HEP Group held a total of 85.75 per cent of the market share. The privately owned supply companies with the highest market share in 2014 were: GEN-I (approximately 6.07 per cent), RWE Energy (former Energija 2 Sustavi with approximately 4.52 per cent) and Proenergy (approximately 2.32 per cent). In the period of September 2013 to September 2014, non-state-owned companies more than doubled their market share to approximately 14 per cent.[7]

In general, electricity tariffs vary starting from approximately US$0.02 to US$0.132 for commercial users, and from approximately US$0.05 to US$0.1 for residential users; tariffs vary depending on the amount of electricity consumed. Additionally, all customers pay a separate feed-in tariff (FIT) of HRK 0.035/kWh (approximately US$0.005/kWh), except customers who must obtain the greenhouse gas emission permit pursuant to the Ordinance of the Croatian Government.[8]

Small hydropower sector overview and potential

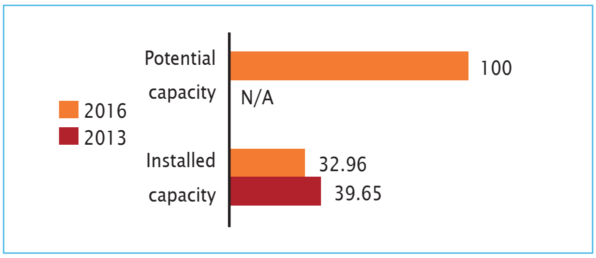
The definition of small hydropower (SHP) in Croatia is up to 10 MW. Installed capacity of SHP is 32.96 MW (Figure 3).[15] The technical potential for installed SHP is 177.1 MW with a potential generation of 567.7 GWh while the economically and environmentally feasible potential is about 100 MW and 350 GWh.11 It should be noted that feasibility studies were conducted on 63 watercourses; the potential for SHP will increase significantly after more studies are completed.

The first hydropower plant installed in Croatia was in 1895, when the 300 kVA Jaruga plant became operational. The plant was rebuilt in 1904 with an installed capacity of 5.4 MW and is still operational.[12] Since that time, installed SHP capacity has increased six-fold.

Developers of a total of eight SHP plants with a combined capacity of almost 5 MW have signed electricity offtake agreements with the market operator HROTE under the

FIGURE 3

Small hydropower capacities 2013-2016 in Croatia (MW)



Sources: *WSHPDR 2013*,[14] Energy Institute Hrvoje Pozar[11,15]
Note: The comparison is between data *WSHPDR 2013* and *WSHPDR 2016*.

country's renewable energy support scheme. As of July 2015, these projects have not yet begun commercial service. The projects are: the 1.4 MW Ilovac plant, developed by Tekonet, the 1.35 MW Prancevici plant on the Cetina River, developed by HEP-Proizvodnja, the 1.3 MW Cabranka 1 plant developed by EUCON, the 0.245 MW Letaj plant by Kapitol Grupa, the 0.155 MW Orljava plant by Mahe Hidroelektrarna, the 0.113 MW Glini plant by Najam Za VAS, the 0.150 MW Klipic plant by VIZ-Molendium, and the 0.225 MW Dabrova Dolina 1 plant by Kelemen Energija. In addition, Prancevici HEP is also planning to reconstruct two existing schemes: the 4.6 MW Fuzine and 1.7 Zeleni Vir plants.[9]

Legislation on small hydropower

Since 2001 coupled together with the adoption of the First Energy Package, the Government has transformed the energy sector by amending the Energy Act (2012) and by adopting the Electricity Market Act and the Act on the Regulation of Energy Activities (2013). In 2013, the Third Energy Package was adopted as well as a new Electricity Market Act (2013), and, in accordance with EU regulations, adopted the Energy Efficiency Act (2014). The licensing and tariff systems were updated in compliance with the new regulations.[7]

The incentive prices for SHP plants according to the Tariff System (Official Gazette No. 133/2013) are as shown on Table 1. As of 2015, only seven sites with a combined installed capacity of 1.6 MW were operating under the FIT, while the remainder did not fall under the incentive system.[15]

TABLE 1

SHP feed-in tariffs in Croatia by capacity

Installed capacity	US$/MWh
< 300 kW	154
300 kW to 2 MW	134
2 MW to 5 MW	126
5 MW to 10 MW	76

Source: Center for Monitoring Business Activities in the Energy Sector And Investments[13]

Renewable energy policy

In 2013, the Government adopted a National Action Plan for renewable energy by 2020, with a greater emphasis on biomass, biogas, cogeneration and SHP. The goal is to increase the renewable energy share from approximately 16 per cent to 20 per cent by 2020. Also by 2020 Croatia aims to have the following share from renewables in total electricity production: 79.6 per cent from large and SHP, 10.5 per cent from wind farms, 8.3 per cent from biomass, 0.9 per cent from geothermal and 0.7 from solar plants.

Renewable producers who obtain the status of eligible producers and who conclude a power purchase agreement (PPA) with HROTE are entitled to receive the FIT for a period of 14 years. The transmission and distribution system operators are obliged to ensure the offtake of all electricity produced from renewable energy sources for up to 14 years. The new tariff system imposes an additional obligation on project developers to install equipment acquired from suppliers and/or authorized representatives of suppliers based in Croatia.[9]

The Government is currently debating a new Renewable Energy Act; as of 2015, the negotiations were still ongoing.[13]

Barriers to small hydropower development

The SHP sector development needs high specific investments and faces limitations related to the environmental impact, historic-cultural heritage and landscape protection. In order to achieve the goals determined in the Energy Strategy, Croatia shall motivate the inspection of remaining watercourses to determine the exact location and potential for construction, facilitate administrative procedures to obtain the necessary permits to construct SHP plants (particularly for plants under 5 MW), and to harmonize energy legislation and other laws related to water management.[10]

4.3.4 Greece

John Kaldellis and Stelios Liaros, Piraeus University of Applied Sciences (former TEI of Piraeus)

Key facts

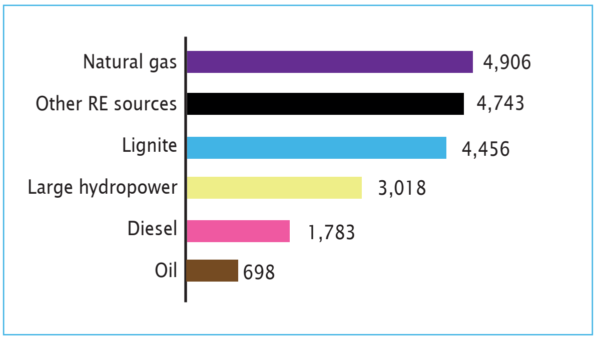
Population	10,903,704[1]
Area	131,954 km[2]
Climate	Greece has a Mediterranean temperate climate presenting mild, wet winters and hot, dry summers. The year can be divided into two main seasons: the cold and rainy period, which lasts from mid-October until the end of March, and the warm and dry season, which lasts from April to October. During the colder period, the coldest months are January and February (average minimum temperature are between 5 and 10°C in coastal areas and 0 to 5°C in inland areas). In the north part of the country the winter is much stronger with temperatures occasionally falling as low as -20°C. In the months of July and August, average maximum temperatures lie between 29 and 35°C.[2]
Topography	Greece is a peninsular country, with an archipelago (Aegean) of about 3,000 islands. The peninsular coastline measures almost 15,000 km. The Pindus mountain range lies across the centre of the country in a north-west to south-east direction, with a maximum elevation of almost 2,650 metres. Central and western Greece feature 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.[2]
Rain pattern	Rainfall in Greece even during winter does not last for many days and winter storms usually end by mid-February. Average annual precipitation varies between 500 and 1,200 mm in the north and between 380 and 800 mm in the south.[2]
General dissipation of rivers and other water sources	The most important rivers in Greece are: Evros, Nestos, Strimon, Axios, Aliakmon, Penios, Arachtos, Acheloos, Sperchios and Alfios. The Acheloos has a considerable water flow of approximately 300 m^3/sec in December, while the flow rate of the Axios is almost 230 m^3/sec in March. The flow rate of the Evros varies between 200 and 220 m^3/sec from January to March.[16] The total domestic water resources are estimated at 85 TWh/year while the annual specific theoretical hydropower potential of Greece accounts for 0.73 GWh/km^2. The technically and economically exploitable hydropower potential is estimated at an annual level of 21 TWh/year.

Electricity sector overview

In 2013, installed capacity in Greece was 19,604 MW, including natural gas (4,906 MW), renewable energy sources (RES) (4,743 MW), lignite (4,456 MW), large hydropower (3,018 MW), diesel (1,783 MW) and oil (698 MW) (Figure 1).[3]

FIGURE 1

Installed electricity capacity by in Greece by source (MW)



Source: Ministry of Environment and Energy[3]

The national Electricity Generation System (EGS) is divided into two main sectors, the interconnected system of the mainland and the autonomous power plants of the Aegean Archipelago islands. Concerning the Archipelago region, the Greek EGS is composed of approximately 40 local Autonomous Power Stations (APSs) which consume imported fuel (diesel and heavy oil).[4] The mainland's electrical grid, in addition to the 16 large hydro installations (3.02 GW), is mainly supported by thermal power stations (TPSs) with a total rated capacity of 9.5 GW, with almost half of them using indigenous lignite and 4.9 GW using imported natural gas.[9] Lignite power units contribute almost 45-50 per cent on an annual basis, while the total electricity generation in Greece (including the autonomous islands) was 50.3 TWh in 2014, which was considerably lower than in 2008.

Across the interconnected system (excluding the autonomous islands) the share of renewable energy sources (RES) (including large hydropower) reached approximately 23 per cent during 2014. Recently, the installed RES-based capacity exceeded 8 GW, although the small hydropower (SHP) contribution remains almost constant.[15] The electrification rate in Greece is 100 per cent.

The significant increase in GDP during 2000-2008 was accompanied by a corresponding increase in electricity consumption, which peaked at the level of 57 TWh during 2008. Subsequently, the economic crisis led to a significant decline in consumer activity resulting in a reduction of both GDP and electricity demand in 2014 down to the levels of 2000. Given the continuing economic uncertainty, the demand for electricity is not expected to recover any time soon.

A series of legislative reforms were attempted in order to liberalize the state monopoly. The undertaken efforts have not led to deep changes. The Public Power Corporation (PPC) maintained its dominant position in the electricity sector, while the main effect of the predefined tender system for meeting the demand for the next 24 hour period was a significant increase in imports of cheap electricity from the Balkan countries neighbouring Greece in the North. During 2014, net electricity imports exceeded 8.5 TWh, accounting for 18 per cent of the domestic energy consumption.

In recent years, the electricity sector has been characterized by several factors including the pressure of withdrawing, due to environmental and economic grounds, the old thermal units (the lignite fired plants of Megalopolis and Ptolemais and the natural gas fired plant of Lavrio); the rapid penetration of 2,500 MW of photovoltaic systems in just two years (due to the particularly high feed-in tariffs (FITs)); and the support provided for the creation of large wind farms, mainly in the Greek archipelagos islands, along with the extensive plans for subsea interconnection of the islands with the mainland.

Although the Ministry of Reconstruction of Production, Environment & Energy supported the creation of new lignite-fired power plants, the protests of environmental organizations and the unfavourable economic situation coupled with a significant decrease in demand for electric power are expected to delay the implementation of similar projects. Moreover, in the context of the European objectives for 2020, Greece will have to cover 40 per cent of its domestic electricity consumption from renewable sources. At the end of 2014, the RES contribution did not exceed the range of 20 to 23 per cent.

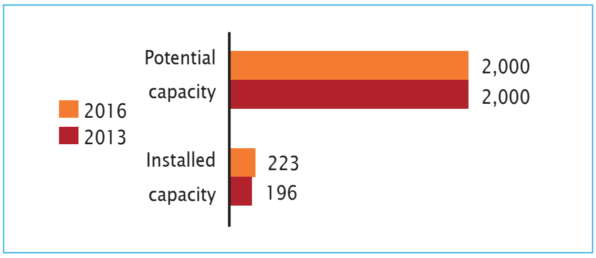
While the cost of electricity generation is based on the respective System Marginal Price, the price of electricity to consumers is controlled by the Government, which often cancels or modifies the values suggested by the competent bodies. Finally, it is worth noting, that since 1994, there has been a predetermined purchase price for electricity from RES, which is also prioritized for purchase by the electrical system unless technical constraints appear. For example, considering the case of the production by SHP plants, the relative price varies at the levels of EUR 90/MWh (US$90/MWh), adjusted every year by a ministerial decree.

Small hydropower sector overview and potential

The definition of SHP in Greece is up to 15 MW. Installed capacity of SHP is 223 MW while the economic potential is estimated to be 2,000 MW indicating that approximately 11 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 14 per cent and potential capacity has not changed.

FIGURE 2

Small hydropower capacities 2013-2016 in Greece (MW)



Sources: Ministry of Environment and Energy,[3] *WSHPDR 2013*[14]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. Data is for up to 15 MW.

In 2014, the total hydropower electricity generation accounted for about 3.8 TWh, i.e. 3.1 TWh from large and 0.7 TWh from SHP stations, contributing 7.5 per cent in the total electricity consumption. From data available, there are approximately 230 SHP plants with a total installed capacity of 223 MW, which is approximately 7.3 per cent out of total hydropower installed capacity. During 2009, installed SHP capacity was approximately 182 MW, demonstrating a limited increase in the range of 7 MW/year which corresponds to the creation of five to 10 SHP plants annually. It is worth noting that of the total installed capacity, only 95 MW correspond to projects with a nominal output of more than 5 MW while the remaining 34 MW are composed of mini and micro projects with a nominal capacity below 1 MW. Correspondingly, the annual electricity production from SHP is increasing slightly from 0.66 TWh in 2009 to 0.7 TWh in 2014, while the estimated average load factor of SHP projects varies between 35 per cent and 45 per cent, almost three times the corresponding value of large hydropower plants in the same period. The technically and economically exploitable hydropower potential is estimated at 21 TWh/year.

A large portion of water resources is concentrated in the western and northern parts of the mainland where one may find the majority of hydropower plants installed.[6] Similarly, all the SHP stations are located in the northern and western parts of the country.[7] Regarding the geographical distribution of SHP plants, the majority of them are located in Central Macedonia (exploiting the waters of the rivers from the north), Epirus (exploiting the rugged terrain of the region) and western Greece in general.[8]

With a national target for 2020 of 350 MW of SHP installed capacity, there is a significant number of projects awaiting implementation. Approximately 130 MW already have binding connection offers while 280 MW are under approval. According to the current estimates of implementation, by 2020 the total SHP capacity will be just over 250 MW.

Although SHP projects do not face significant environmental problems or social reaction as is the case with large hydroelectric plants whose development in Greece faces serious obstacles, there is no serious state encouragement for their implementation.[10] The initial development cost of an SHP plant ranges from EUR 0.8 million/MW to EUR 1.5 million/MW with the most likely value corresponding to EUR 1.2 million/MW (0.89 million, 1.67 million, 1.3 million US$/MW).[11,12] During the last decade, state subsidization of SHP projects accounted for up to 40 per cent of the initial capital for new SHP projects.[11] Even with that incentive policy, SHP projects are an economically efficient investing option, as attested to, by the investor's interest even today.

Renewable energy policy

The Greek State, since implementing the European policy for independence from imports and reduction of environmental impacts of fossil fuels, officially supports the further penetration of RES in the domestic energy balance. In this context some ambitious and often poorly rated objectives have been set up, which mainly include the massive installation of large wind farms (estimated installed capacity of 7-8 GW by 2020) and the installation of solar photovoltaic panels (estimated installed capacity by 2020 of 2.5 GW). In both cases, serious problems have been experienced, in particular the lack of electrical networks and negative social reactions to the establishment of large wind farms have limited the installed wind power at the level of 2 GW, through 2015.[9]

Correspondingly, the installed capacity of PV panels by the end of 2014 exceeded the targets of 2020, bringing the State to a position of limiting the uncontrolled dynamics of the domestic market by both dramatically reducing the electricity purchase price (which in 2012 stood at the very high for the interconnected grid value of EUR 0.5/kWh (US$0.56/kWh)) and by imposing a retroactive taxation of 30 per cent on revenue of PV stations for the years 2012 and 2013. In this context, the utilization of water resources experienced a lack of governmental interest, as large hydro faced persistent reaction of local communities and small hydro was not considered capable of significantly changing the national energy mix.

Barriers to small hydropower development

One of the major drawbacks decelerating SHP penetration in the local electrical market is the administrative bureaucracy. Despite the efforts of the Greek State, there is a substantial number of documents that one should provide in order to start the construction of a new SHP station. In fact, for obtaining the final licence an investor needs to wait for an extended period (usually up to 3 years).[12]

An additional serious obstacle for the creation of a considerable number of new SHP plants is the absence of an integrated national water management plan. This problem hinders the exploitation of potential small hydro locations of the country. In most cases examined, the water potential exploitation status is totally unclear, hence local municipalities and agricultural cooperatives raise exclusive or preferential proprietary rights on the existing water resources. Essentially, in some cases local municipalities and agricultural cooperatives exercise pressure, via their political influence, on the utilization planning of the available water potential. Thus in several cases SHP plants cannot operate continuously since the electricity production is not a priority. However, via careful and fair water potential management one may cover the parallel requirements of local communities/unions without zeroing the electricity generation from SHP plants of the area.

Taking into account the relatively small size of the installations and the corresponding limited budget, most big energy-related construction companies are not showing much interest in similar small size projects. Hence, the development of small or mini hydropower installations is realised by small private companies with limited socio-economic influence on the local and national level. These relatively small firms have neither the necessary know-how nor the technical equipment to optimize their plants. Only in case of a number of successive SHP stations along the same river one may take advantage of scale economies. The result of this situation is the remarkable construction time required and the violation of the initial budget. Additionally, in many cases, the developed SHP stations are oversized, since the subsidy amount depends only on the installed power of the station and not on the corresponding energy yield. In these cases, the existing SHP stations do not operate for a considerable period of the year due to the low water volume rate available and the operational restrictions imposed by the hydro turbines of the installation, in order to avoid increased wear and maintenance of the equipment.

4.3.5 Italy

Gianluca Lazzaro, University of Padova

Key facts

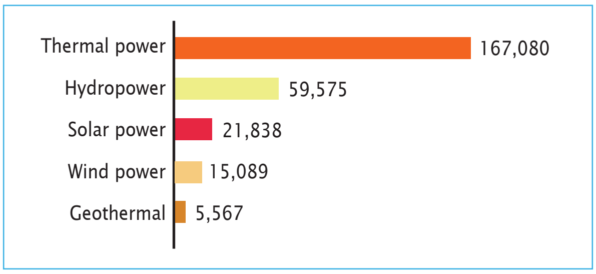
Population	61,336,387[11]
Area	301,340 km^2
Climate	Cold winter, hot and humid summer in the north; mild winter in central Italy; very hot summers and very mild winters in the south and in the islands. Average temperatures are between 3°C (north) and 14°C (south) in January and between 28°C (north) and 30°C (south) in July.[10]
Topography	The country can be divided into four topographic regions: north of the peninsula, the central region, the southern region and the islands. The territory is mostly mountainous; the Alps are the northern boundary of the country and the Apennine Mountains represent the backbone of the peninsula; the largest plain is the Po Valley (71,000 km^2); the highest peak is Monte Bianco (4,810 metres above sea level).[10]
Rain pattern	Mean annual rainfall is about 1,000 mm; highest values occur in the north-east (> 2,000 mm); in the islands and in the south, rainfall rarely exceeds 500 mm per year.[10]
General dissipation of rivers and other water sources	Rainfall is mainly lost due to evaporation (about 500 mm per year); water consumption also reduces runoff availability (385 litres per capita per day). The longest and most important river is the Po, which is located in the northern regions along with the Adige River. In the central region, the most influential are the Reno and Arno Rivers, while in the south it is the Bradano River.[10]

Electricity sector overview

In 2014 electricity generation was 269,148 GWh and satisfied about 86 per cent of the national demand (310,535 GWh).[1] Imported electricity provided the remaining fraction (43,716 GWh).[1] Renewable sources (hydropower, solar and wind) have become increasingly important since 2011 thereby reducing the use of fossil fuels (Figure 1).

FIGURE 1

Electricity generation in Italy by source (GWh)



Source: Terna [1]

Net generation capacity in 2014 was 121,762 MW (2.2 per cent less than in 2013), which includes thermal (68,417 MW), hydro (21,979 MW), solar (18,609 MW), wind (8,683 MW), other (4,074 MW). Minimum and maximum annual grid load values observed in the same year were 18.7 GW and 51.6 GW (12 June 2014).[3]

The national electricity demand in 2014 confirmed the decreasing trend (2.5 per cent less than in 2013) which was observed in the previous year (3.0 per cent less than in 2012).[1] This trend is strongly influenced by the decline of energy demand for industrial production, mainly driven by a declining economy. In 2013, the Gross Domestic Product (GDP) decreased (–1.9 per cent) for the second consecutive year (–2.5 per cent in 2012). Moreover, slight declines were also observed in tertiary (first time since 1963) and domestic consumption.[2]

In Italy, private companies manage the production, transmission and distribution of electricity. Competition in these sectors is allowed and promoted by the Authority of Electricity and Gas (AEEG, Law 481/1995). Terna S.p.A. is the Transmission System Operator and owns the whole national high-voltage transmission grid. Eleven other companies are involved in the management of low-voltage grids at regional levels. In 2013, 138 distribution companies were employed. In particular, Enel Distribuzione S.p.A. provided electricity to the largest portion of domestic and industrial users (86 per cent).[2]

Approximately 6.3 per cent of the produced electricity was lost along transmission and distribution networks (19,451 GWh).[1] Moreover, several connection lines are now insufficient and often suffer congestion. Therefore, investments are needed to improve the aging energy infrastructure in order to increase the efficiency of networks and guarantee power supply for new users. The electrification rate is 100 per cent.

The Government's plans mainly involve the reduction of fossil fuels for electricity production and the safety of power supply, which has been recently imperilled by conflicts in Libya and Ukraine. Consequently, the diversification of sources for energy production and the promotion of renewable energy (RE) are objectives of the Government.

The first regulated 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 contracts. The market, regulated by the Energy Market Manager (GME), mainly consists of the Day-Ahead Market (MGP) whose trades involve electricity for the next day. GME is the central counterparty in the transactions concluded in the MGP. Then, sell/purchase proposals may be changed during following electricity market sections.

In 2014, the Italian electricity market was characterized by a mean electricity price of EUR 52/MWh (US$57/MWh), with a decrease of 17.3 per cent compared to 2013 (the lowest ever seen since the introduction of the market).[4] This decrease in the price mainly reflected the reduction of the electricity demand (primarily a consequence of economic difficulties) and the growth of renewable sources of energy.

A reduction in the mean electricity price occurred in all regions in 2014 compared to 2013: EUR 52/MWh (15 per cent less) in the continental region, EUR 52/MWh (15 per cent less) in Sardinia, and EUR 81/MWh (12 per cent less) in Sicily (57, 57 and 90 US$/MWh, respectively).[4]

The electricity price in Italy is greater than that observed in other European markets, which ranged between EUR 33/MWh (US$36/MWh) in Germany and EUR 42/MWh (US$46/MWh) in Spain in 2014.[4] Italy strongly depends on gas, which is the most expensive source, and thus suffers from the increase in gas prices more than countries characterized by a better-balanced mix of electricity sources.

Small hydropower sector (SHP) overview and potential

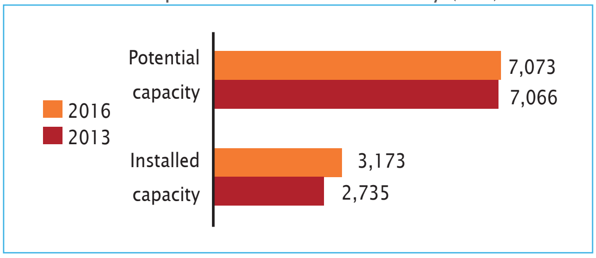
The definition of small hydropower (SHP) in Italy is up to 10 MW. Installed capacity of SHP is 3,173 MW, while the economic potential is estimated to be 7,073 MW, indicating that approximately 45 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 16 per cent while estimated potential has increased by less than 0.1 per cent (Figure 2).

SHP plants are classified according to their maximum capacity as:

- Micro hydropower: less than 0.1 MW;
- Mini hydropower: between 0.1 MW and 1 MW;
- SHP: between 1 MW and 10 MW.

FIGURE 2

SHP capacities 2013-2016 in Italy (MW)



Sources: *WSHPDR 2013*,[9] World Energy Council[8]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

In 2014, there were 2,304 micro and mini hydropower plants in operation with an installed capacity of 679 MW, and 825 SHP plants with a capacity of 2,494 MW.[5]

Italy is the leading European country for installed capacity and electricity generation, taking into consideration hydropower plants with less than 10 MW.[6]

The energy produced by all SHP plants in 2014 was 14,141 GWh (3,148 GWh by micro and mini HP and 10,993 GWh by SHP).[3] The number of micro and mini plants rose by 8.2 per cent compared to 2013, and the number of small plants rose by 1 per cent. The same comparison in terms of energy produced is meaningless as inter-annual climatic fluctuations strongly affect the water resources available for HP plants.

Large hydropower plants (greater than 10 MW) still represent the most important source of hydroelectricity in the country. Thus, in 2014 large hydropower plants produced about 44,404 GWh (76 per cent of the total hydropower generation).[7]

The gross hydropower potential in Italy is estimated to be about 200 TWh/year, of which 38 TWh/year is associated with SHP.[8] Technical and economic constraints reduce the HP potential production to about 50 TWh/ year.[8] Estimates of the technical SHP potential range between 12.5 TWh and 20 TWh.[6,8] The potential installed capacity available is around 3,900 MW.[6] Interestingly, although the potential for additional development in Italy is low compared to that of other countries, future policies will likely favour additional HP development.

Renewable energy policy

Italy has placed the growth of renewable sources of energy among the priorities for the energy development of the country. In accordance with the EU Directive 2009/28/CE, in 2020, 17 per cent of the total energy demand of the country will be provided by RE.

The National Renewable Energy Action Plan (2010) has defined the strategies to achieve the targets prescribed by the EU and established the expected growth from 2010 to 2020 of the installed capacity and the energy production for each renewable source of energy.

Moreover, RE will play an important role in reducing CO_2 emissions by 40 per cent, to 70 per cent below 2010 levels, by 2050. This target was established at the G7 leader's summit in June 2015 and will lead to the decarburization of the global economy over the course of this century in Italy as well as in other countries worldwide.

Since 2012, the Government has introduced an annual threshold on RE incentives, which is EUR 5.8 billion (US$6.4 billion) (not including solar energy). Several RE development schemes actually exist in Italy:

(a) CIP6 (1992)
CIP6 was the first system of incentives for RE adopted in Italy. It is no longer in use but there are plants that still benefit from this system. The increase of installed RE capacity thanks to CIP6 has been estimated at 6.5 GW

(b) Green Certificates (1999)
New RE plants receive a number of GC according to their energy production (1 GC = 1 MWh). GC can be sold to industries that are required to produce a fraction of energy with renewable sources, but are not able to do it on their own. GC average annual price ranged between 80 and 120 EUR/MWh (90 and 135 US$/MWh) (excluding VAT) [4]

(c) Feed-in Tariffs (FITs) (2008)
FITs include electricity prices and incentives, and are guaranteed for several years after the activation of the plant. Small producers usually prefer this support scheme because GC markets can be very complex. FITs simplify financial planning for plants with a small capacity

Legislation on small hydropower

The National Renewable Energy Action Plan (2010) predicted an overall hydropower production of 42 TWh in 2020. Even though this goal has already been achieved, major efforts will be made in compensation for the reduction of the efficiency of large HP plants (some of them were built 100 years ago) with the construction of new SHP plants. In fact, the Government expected the SHP generation to grow from 9.2 TWh in 2010 to 12.08 TWh in 2020. However, SHP electricity production in 2014 already surpassed this target.[12]

The development of Italian hydropower production in the 20th century has been typically associated with the construction of conventional plants that rely on large dams, which induce dramatic changes in the landscape and significant alteration of river discharges. However, conventional HP plants are close to saturation in most EU countries, including Italy.

The unexploited hydropower potential is thus associated with SHP. This sector has become increasingly important during the last decade thanks to the Government's policies, which have caused rapid installation of new SHP plants beyond expectations.

SHP growth has been driven by comprehensive FIT (EUR 0.22/kWh for 15 years; US$0.24/kWh) introduced in 2008 as an alternative to Green Certificates for plants with a capacity up to 1 MW. In July 2012, a ministerial decree introduced a new support scheme for SHP plants. FIT (and subsidized period) actually depends on the maximum capacity (P) and is also provided for plants up to 10 MW according to the following scheme:

- $1 < P \leq 20$ kW: EUR 257/MWh (US$285/MWh) (20 years);
- $20 < P \leq 500$ kW: EUR 219/MWh (US$243/MWh) (20 years);
- $500 < P \leq 1,000$ kW: EUR 155/MWh (US$172/MWh) (20 years);
- $1,000 < P \leq 10,000$ kW: EUR 129/MWh;
- US$143/MWh for 25 years.

However, laws prescribe the maximum annual installed capacity for each source of energy. In particular, no more than 70 MW of additional hydropower capacity can be installed each year. If new SHP projects exceed the annual capacity growth threshold, plants are ranked and feed-in tariffs are guaranteed only for those having less environmental impact. Plants producing less than 50 kW avoid this procedure and are supported by feed-in tariffs, and the payback period for SHP investments is approximately 5 years.

A new support scheme will begin in January 2016, probably reducing the annual hydropower production threshold and feed-in tariffs.

Barriers to small hydropower development

The main barriers to SHP development regard the following:

(a) Authorization process
The authorization process in Italy lasts on average 2-3 years. Permissions (water concession, construction licence, etc.) come from different departments. Moreover, there is no substantial difference between the water concession for small and large HP plants. Finally, the recent introduction of a threshold on the annual installed capacity (and consequently the ranking procedure for competitive plants) has slowed down the process even more.

(b) Environmental requirements
Even though SHP inflicts a smaller impact on aquatic ecosystems and local communities compared to large dams, it cannot prevent stresses on plant, animal, and human well-being. Additionally, the

negative cumulative effect of SHP plants operating along the same river threatens the ability of stream networks to support biodiversity. Currently, the prediction of the long-term impacts associated with the expansion of SHP projects induced by global-scale incentive policies remains highly uncertain.

Although limiting HP exploitation, environmental regulations are thus needed to preserve river networks. An example is the regulation of the Minimum Environmental Flow (MEF), which was established by Water Authority. Weirs crossing the river must also be equipped with fish passages allowing migration. Moreover, SHP plants with a capacity larger than 100 kW are required to undergo an Environmental Impact Assessment (EIA).

Given the recent expansion of SHP plants in Italy and the disturbance on river ecosystems, an emphasis must be placed on combining energy/monetary needs with environmental preservation. Small hydro technology is likely to gain a higher social value in the next decades if the environmental and hydrologic footprint associated with the energy exploitation of surface water will take a higher priority in civil infrastructure planning.

(c) Social conflicts

Social movements against SHP are growing in Italy, especially in the northern region (Alps). Usually concentrated in less developed, mountainous areas, the hydroelectricity generation is associated with negative externalities in proximity to the plants, and the downstream communities take most benefits. The goal of these movements is to prevent further exploitation of mountainous river networks that are already altered by water regulation due to dams. There are examples of new SHP plants that have been stopped or delayed because of this opposition.

4.3.6 Montenegro

Igor Kovacevic, Montconsult

Key facts

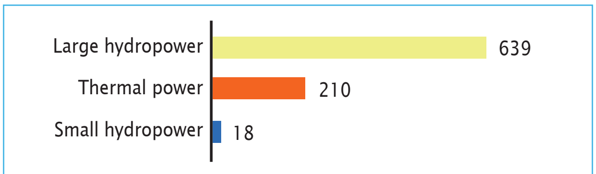
Population	625,266[1]
Area	13,812 km^2 [1]
Climate	A Mediterranean climate in the south and the Zetsko-Bjelopavlicka plain regions are characterized by long, hot and dry summers between June and August and relatively mild and rainy winters between December and February. The north has a continental climate with large daily and annual temperature variations and low annual rainfall. Average temperatures range from –0.9°C in January to 18.8°C in July.[2]
Topography	Topography ranges from high mountains in the north of the country falling to a narrow coastal plain on the Adriatic Sea in the south and south-west. There are a number of peaks exceeding 2,000 metres including Bobotuv Kuk which, at 2,523 metres, is believed to be the highest point in the country. The coastal region is noted for its active seismicity.[2]
Rain pattern	Mean annual precipitation in Montenegro is 1,745 mm. However, this ranges from 777 mm to 4,580 mm, which is the highest precipitation level in Europe. The lowest precipitation is in the north and the highest in the central regions where continental and Mediterranean climate conditions meet.[3]
General dissipation of rivers and other water sources	Significant rivers of Montenegro include the Drina, Tara and Lim. Several rivers, including the Tara, Piva, and Moraca, pass through mountainous areas and have carved valleys or canyons, some up to 1,200 metres deep. The largest lake is Lake Skadar, and is shared with Albania; the lake combined with Zeta Valley provides the most fertile area in the country.[3]

Electricity sector overview

Total installed capacity is approximately 867 MW. The majority is provided by two large hydropower plants, Perucia (307 MW) and Piva (332 MW), contributing approximately 74.4 per cent with a thermal power plant, Pljevlja (210 MW), contributing 24.4 per cent (Figure 1). The remaining installed capacity is provided by small hydropower (SHP) plants. Perucica and Piva began operating in 1960 and 1976 and have average annual productions of 853.6 GWh and 737.3 GWh respectively. Pljevlja began operating in 1982 and has an average annual production of 1,400 GWh.[4]

FIGURE 1

Installed electricity capacity in Montenegro by source (MW)



Source: Government of Montenegro[4]

Planned electricity generation in 2014 was 3,108 GWh with 1,702 GWh(or 55 per cent), generated from hydropower.[4] Annual net electricity import was expected to be 441 GWh. The total electricity generation in 2014 was 3,105 GWh, 5 per cent less than planned and 20 per cent less than in 2013, when precipitation was higher than usual. Total electricity demand in 2014 was 3,546 GWh. Montenegro has a 100 per cent electrification rate.[4]

The electricity sector in Montenegro has been in transition over the past decade. Montenegro is a candidate country for the European Union (EU) and a contracting party of the Energy Community Treaty. As such it has an obligation to follow the EU policy in energy and the environment.

Elektroprivreda Crne Gore (EPCG) is a vertically integrated company operating as the distribution system operator, public supplier and owner of all major generation units in Montenegro. Previously EPCG was also responsible for transmission however, in 2009, Crnogorski elektroprenosni sistem (CGES) was established as the transmission system operator, which separated transmission from EPCG. Both companies are owned by the State of Montenegro with a majority share of 55 per cent. The major minor shareholders are A2A, with 43 per cent of EPCG, and CGES Terna with 22 per cent of CGES. Both are Italy-based.

The transmission network was originally part of the ex-Yugoslavian 400 kV cycle and today the Government wants to extend this network to become an electricity hub in South-eastern Europe. In 2011, a new 400 kV transmission line was constructed between the capital, Podgorica, and Tirana, the capital of Albania.

Furthermore, a 375 km long undersea electricity cable between Italy and Montenegro with converter stations on both coasts, overhead 400 kV lines in Montenegro and interconnection lines to Serbia and Bosnia and Herzegovina are under development.

The distribution system is undergoing significant development with a focus on the implementation of an advanced management system that includes replacing old electricity meters with smart meters. EPCG plans to replace 240,000(or 86 per cent), of active electricity meters by the end of 2016. At the same time, reconstruction of the low-voltage network is ongoing. As a result, the electricity losses from the distribution network are constantly decreasing (16.8 per cent in 2014).

Based on decisions of the Regulatory Energy Agency (REA) from 2009 and the 2010 Law on Energy, the electricity market was opened up in 2015, including for households. Currently, only EPCG is active on medium and low-voltage levels.

The REA is responsible for determining tariffs and prices on medium and low-voltage levels for electricity supplied by EPCG. The retail price for distributed consumer categories is calculated based on: active electricity, engagement of transmission and distribution capacities, transmission and distribution network losses, fixed fees for electricity system operators and VAT. Active electricity and network losses are defined for high-tariff (07:00-23:00) and low-tariff (23:00-07:00 and Sundays) periods, whereas tariffs for network capacities are not dependent on time periods. The retail electricity prices for the distributed customer category, valid from August 2014, are EUR 0.104 (US$0.139) per kWh and EUR 0.072 (US$0.096) per kWh, for high and low tariffs respectively. The VAT in Montenegro is 19 per cent.

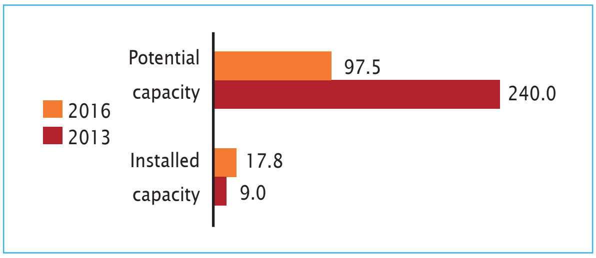
Small hydropower sector overview and potential

In Montenegro an SHP installation is defined as a plant with an installed capacity less than 10 MW. The current installed capacity of SHP is 17.8 MW with a total potential of at least 97.5 MW, which is planned to be harnessed by 2019. Therefore, approximately 18 per cent of the discovered SHP potential has been developed so far (Figure 2).[8]

SHP represents approximately 3 per cent of total hydropower capacity in Montenegro. Prior to 2014, the SHP installed capacity of 9 MW was derived from 7 plants owned and operated by EPCG. There is no specific focus of EPCG on these small facilities and their operating condition is poor. In 2007, however, the Government began giving concessions to private investors for SHP construction. This agreement includes development, construction, operation and maintenance for up to 30 years after which all equipment and facilities transfer to state ownership. As of 2015, six SHP plants have been constructed by private investors and are operational. These SHP plants are the first new electricity generators to be installed in 30 years and have a combined installed capacity of 8.8 MW and an estimated electricity generation of 28 GWh.[8]

FIGURE 2

Small hydropower capacities 2013-2016 in Montenegro (MW)



Sources: Green Home and World Wide Fund,[8] *WSHPDR 2013*[11]
Note: A negative change can be due to access to more accurate data. The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

As of 2015, 43 new, privately owned, SHP plants, including the 6 operational plants, have been approved with a combined capacity of 83 MW and an estimated generation of 269 GWh. Four tenders for concessions have been undertaken since 2007 resulting in the approval of 14 valid concession agreements to construct 30 SHP plants with a combined installed capacity of 75 MW and an annual generation of 236 GWh (Table 1).[8]

In order to improve and accelerate the authorization process for 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. Under the current regulation, energy permits can be issued for plants up to 1 MW on rivers with a generation potential less than 15 GWh.[7] As of July 2015, 13 energy permits were issued under this scheme (Table 1).[8]

Planned reconstruction by EPCG is also outlined by the Energy Development Strategy until 2030 to bring existing EPCG plants up to a combined capacity of 11.4 MW. By

TABLE 1

Overview of approved small hydropower plants as of 2015

Type of agreement	Number of contracts	Number of sites	Estimated capacity (MW)	Estimated generation (GWh)
Tender	14	30	74.72	236.18
Energy permit	13	13	8.69	32.82
Total	**27**	**43**	**83.41**	**269.00**

Source: Green Home and World Wide Fund[8]

2019, it is planned to achieve a total installed SHP capacity of 97.5 MW with 11.2 MW from plants up to 1 MW and 86.3 MW from 1-10 MW plants.[8] However, the actual potential figure is likely to be significantly higher. The Energy Development Strategy includes data from the 2001 Water Master Plan which estimates the overall theoretical hydropower potential of Montenegro as between 10.6 TWh and 10.8 TWh and the technical potential between 5.0 TWh and 5.7 TWh until 2030 (Table 2).

TABLE 2

Theoretical and technical hydropower potential

Source	Theoretical potential (TWh)	Technical potential (TWh)
Main rivers	9.8	4.6-5.3
Small rivers	0.8-1.0	0.4
Total	**10.6-10.8**	**5.0-5.7**

Source: Strategy of Energy Development of Montenegro up to 2030[5]

However, the theoretical and technical potential of small rivers could be underestimated. Beginning in 2007, Montenegro has made in-situ hydrometric measurements at locations on small rivers that could be used for the construction of SHP plants. Three series of one-year measurements were finished for approximately 40 locations on 35 rivers. The programme continues and today hydrometric measurements are ongoing.

Moreover, in 2010, hydrometric measurements on the smallest rivers were started, specifically on small rivers most suited to the development of SHP plants with an installed capacity less than 1 MW. Aside from past and ongoing measurements, the state hydrometric measurement network is continuously improving in terms of the number of automatic hydrometric stations and the quality of the equipment. Therefore, it is expected that the estimated hydropower potential on individual water streams will become higher and more reliable.

Renewable energy policy

The Strategy for Energy Development in Montenegro up to 2030 defines technologies for electricity generation in the period up to 2030. New facilities for electricity generation are planned from coal, hydro, wind, solar power and biomass. Hydropower will still be the dominant source for electricity generation. Existing hydropower plants will be reconstructed and new plants constructed.

In addition, the National Renewable Energy Action Plan (NREAP) up to 2020 was adopted in 2014.[9] Based on the Energy Community Ministerial Council Decision D2012/04/MC-EnC, Montenegro is obligated to adopt Renewable Energy Directive 2009/28/EC and establish a national target of 33 per cent of total energy consumption and 51.4 per cent of total electricity consumption from renewable energy sources by 2020.

Legislation on small hydropower

The NREAP also defines targets for different types of renewable energy. Total installed capacity from hydropower is planned to total 826 MW with an annual generation of 2,050 GWh by 2020. Installed capacity of SHP plants is planned to total 97.5 MW with an annual generation of 287 GWh (Table 3). With the new approved and reconstruction projects expected to increase SHP to 94.8 MW, the country is close to achieving this objective.

TABLE 3

National goals for construction of small hydropower plants up to 2020

Plant size	Capacity (MW)	Generation (GWh)
Up to 1 MW	11.2	35
1-10 MW	86.3	252
Total	**97.5**	**287**

Source: National Renewable Energy Action Plan Up To 2020[9]

Further development of renewable policy has also been undertaken with a new energy law adopted in 2010 and a renewable energy regulatory framework set up between 2010 and 2012, which has established a feed-in tariff scheme based upon European regulations. New producers from renewable sources receive the status of privileged producers for 12 years entitling them to feed-in tariffs and priority delivery. Feed-in tariffs for SHP are based on annual electricity generation and favour the construction of smaller facilities (Table 4).[10] In addition, a flat rate feed-in tariff of EUR 0.07/kWh (US$0.09/kWh) has been established for refurbished SHP plants.[10]

TABLE 4

Feed-in tariffs for small hydropower plants

Annual generation	Feed-in tariff (Euros (US$) per kWh)
Up to 3 GWh	0.1044 (0.1391)
3-15 GWh	0.0744 (0.0991)
More than 15 GWh	0.5040 (0.0671)

Source: Government of Montenegro (2011)[10]

Barriers to small hydropower development

Although the Government has taken an active role in improving the legislative and development processes for SHP, many obstacles to developing an attractive environment for investment still remain. These include:

- Missing general and strategic water plans;
- Disagreement between strategic plan documents in energy, water and environment sectors and the national and local spatial plan documents;
- Weak distribution networks in regions where SHP potential is highest;
- Weak administrative capacities in water, ecological and energy institutions that deal with this issue.

4.3.7 Portugal

Paulo Alexandre Diogo and António Carmona Rodrigues, New University of Lisbon

Key facts

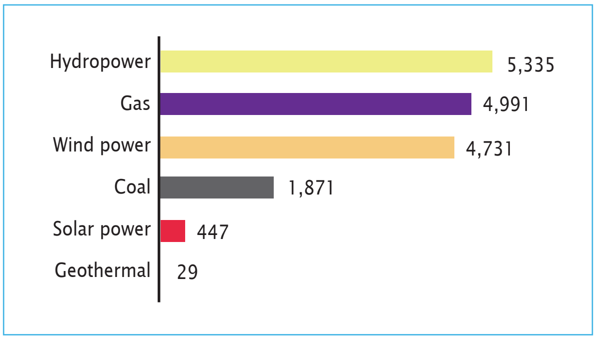
Population	10,374,822[1]
Area	92,225.6 km^2 [1]
Climate	Portugal is characterized by a temperate climate with hot and dry summers between June and August in the south, and dry and mild summers in the north. Average annual temperature varies from 7 °C in the northern regions of the country and 18 °C in the southern regions.[1]
Topography	The centre and north of Portugal are mountainous regions with several mountain chains reaching as high as 1,500 to 1,900 metres. In the south plains are characteristic although some high mountains can also be found. At 1,993 metres, Serra de Estrela is the highest point in mainland Portugal. However, the summit of Mount Pico, on the Azores, is higher at 2,351 metres.[3]
Rain pattern	Total annual precipitation ranges between 2,400 mm and 2,800 mm in the north-western coastal mountains to 400 mm in the south. In the south monthly variations are more intense and 80 per cent of precipitation tends to occur during the wet season, typically from October to March, with November and December generally the wettest. July and August are the hottest and driest months.[3]
General dissipation of rivers and other water sources	Transboundary river basins in Portugal represent around 64 per cent of the country's territory, with the largest rivers being the Tagus, Douro and Guadiana; the main rivers within the territory of Portugal are the Mondego, Vouga and Sado. In 2005 the country's total water dissipation per inhabitant was 6,545.97 m^3/year. River flows have high seasonal variations due to precipitation patterns, mainly in the south of the country, and hydropower dam operation occurs mainly in the north.[3]

Electricity sector overview

In 2014, total electricity generation in Portugal was 48,999 GWh. In 2013 installed capacity was 17,404 MW comprising 5,335 MW of hydropower, 4,731 MW of wind power, 4,991 MW of gas, 1,871 MW of coal and cogeneration plants, 447 MW of solar and 29 MW of geothermal power (Figure 1).[13]

FIGURE 1

Installed electricity capacity in Portugal by source (MW)



Source: Direção Geral de Energia e Geologia[13]

Having no fossil fuels available in the country, Portugal must import most of its required energy, this is demonstrated by a rate of energy dependence of 79.2 per cent (2012).[1] This dependence rate has been reduced since 2005, mostly as a result of increasing hydropower installed capacity and production.

The electrification rate in the country is close to 100 per cent and the overall energy mix is strongly influenced by the transport sector, which represents 36 per cent of primary energy consumption and 73 per cent of total oil demand for energy purposes.[10]

The privatization process of the energy sector has been recently concluded, partly as a result of the bailout process enforced between 2011 and 2014. Accordingly, the main energy company Energias de Portugal (EDP) became completely independent from the State with the China Three Gorges Corporation becoming the main shareholder with 21.35 per cent control. In 2014, the privatization of the electricity grid infrastructure was also concluded, with the State Grid of China becoming the main shareholder with a 25 per cent share. EDP remains the main electricity distributor although the energy market is being gradually liberalized.

On the Portugal mainland, transmission is handled by a single company, Rede Eléctrica Nacional (REN) while most of the distribution networks are handled by, EDP Distribuição, and also by some low-voltage electricity distribution operators. Electricity suppliers are responsible for managing the relations with end consumers, including billing. In Portugal, mainland electricity can be sold on a liberalized market, through free suppliers, and on a regulated market, through the last resort supplier. In 1998, the Portuguese and Spanish Administrations began building the shared Iberian Electricity Market (MIBEL).

The market 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, updated with Decree-Law No. 84/2013. The process of market liberalization is therefore not complete with some regulated tariffs still in place. Though it has been postponed since the initial date was fixed, this is expected to cease in the near future and impacts on the energy market are yet to be evaluated as are all the effects associated with the privatization process.

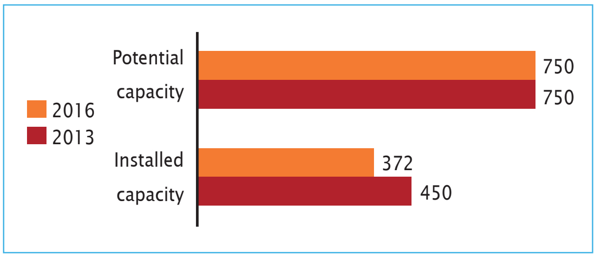
Historical tariffs are well documented but have been subject to multiple tax-related changes, some with relevant impacts on the consumer costs. Consumer prices have varied over the years. Although some tariffs have regional differences, they are generally market driven. Average costs in the second half of 2014 were EUR 0.223 (US$0.297) per kWh and EUR 0.119 (US$0.159) per kWh for residential and industrial consumers, respectively.[1]

Small hydropower sector overview and potential

In Portugal, small hydropower (SHP) is defined as plants with a capacity of 10 MW or less. Current installed capacity is 372 MW. However, there are no accurate or complete studies for SHP potential.[1] Nonetheless the country's National Renewable Energy Action Plan (NREAP) is aiming for a total of 750 MW from 250 plants by 2020 indicating that at least this potential exists.[15] Current capacity constitutes approximately 50 per cent of this target.

FIGURE 2

Small hydropower capacities 2013-2016 in Portugal (MW)

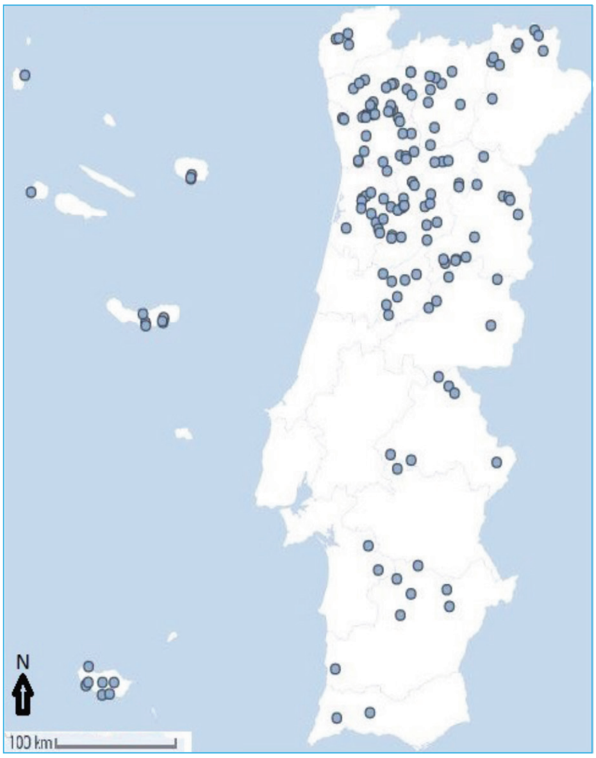


Sources: *WSHPDR 2013*,[8] Direcção Geral de Energia e Geologia[14]
Note: A negative change can be due to access to more accurate data. The comparison is between data *WSHPDR 2013* and *WSHPDR 2016*.

As of 2014, there were 159 SHP plants in Portugal constituting approximately 4 per cent of the total renewable energy capacity and 8 per cent of the total hydropower capacity (Figure 3). As part of the NREAP, Portugal is 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. In order to achieve its goals, the NREAP highlighted the need for a specific plan to develop SHP potential. However, currently, there is no plan in place.[15]

FIGURE 3

Location of small hydropower plants



Source: Energias Endógenas de Portugal[6]

Since 2007, the National Plan for Dams with High Hydropower Potential has been underway, defining the construction of 10 new large dams. This plan is, however, only half complete and its continuation may depend on governmental options, international energy prices and limits to energy exports to European countries associated with energy market constraints that represent real obstacles in pursuing an increase in large hydropower capacity.

Renewable energy policy

A key challenge for the Portuguese energy sector is to reduce energy dependence, a goal which can only be achieved by developing renewable energy sources. Currently renewable energy sources constitute a 27 per cent share of the energy sector and a 58 per cent share of the electricity sector.[9] According to a study developed by Deloitte for the Renewable Energy Association (APREN), although future renewable energy growth should be below the European Union and global expected growth, a further 7,100 MW of installed power is expected from renewable sources over the next 16 years.[10]

Current energy policy is built on two major pillars: sustainability and economical rationality on the basis of energy efficiency; and endogenous renewable sources incorporation and cost reduction. Goals outlined in the National Plan of Action for Energy Efficiency, National Action Plan for Renewable Energies and the Program of Energy Efficiency in the administration are to:

- Reduce greenhouse gases in a sustainable way;
- Diversify primary energy sources;
- Increase energy efficiency;
- Contribute towards an increase in economic competitiveness.[11,12]

Legislation on small hydropower

There is no regulation published on establishing 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.[9]

In Portugal, the support scheme in place for SHP is its feed-in tariff (FIT). The Decree-Law No. 225/2007 indicates an average reference FIT of EUR 7.5-7.7 /kWh (US$8.5-8.7), with a limit set to the first 52 GWh/MW or up to 20 years, whichever is reached first. It could be increased to 25 years in exceptional cases. In 2010, a new tariff was defined by the Decree-Law No. 126/2010 specifying for the public tender launched in that year: EUR 9.5/kWh (US$10.8), up to 25 years.[9]

Barriers to 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. On average the licensing procedure for an SHP plant can take 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 support mechanisms. A reduction in the value of the FIT in 2005 has led to a significant decrease in the number of new SHP plants.
- In general technical capacity is available, while state-of-the-art information systems and effective social awareness of environmental issues support the growth of the renewable energy sector. Furthermore, the national electricity grid infrastructure is of no major concern. However, limitations on energy exports are an obstacle to the increase of renewable energy sources. On the other hand, SHP is socially preferred over large dam construction as environmental and economic impacts are reduced.

4.3.8 Serbia

Milena Panic, Marko Urošev and Ana Milanovic Pešic, Geographical Institute; Jovan Cvijic, Serbian Academy of Sciences and Arts

Key facts

Population	7,129,366[1]
Area	88,499 km²
Climate	Continental climate (in areas of plains, basin rims and river valleys) and mountain climate in the southern part of the country. In the period 1961-2010, the average annual temperature ranged from 3°C in the highest parts of mountains to 12.3°C in Belgrade. The average temperature in January ranges from 4.6°C in mountainous areas (Kopaonik) to 2.1°C in Belgrade and in July from 11.3°C in the mountainous areas (Kopaonik) to 22°C in the valleys (Negotinska krajina, Belgrade).[3]
Topography	The relief is characterized by three types of regional morph structures: plains and basin rims, located in the northern and eastern part of the country and the areas of mountains and valleys in the southern part (Dinarides, the mountains of the Vardar Zone and the Serbo-Macedonian mass, Carpatho-Balkanides). The highest point is Deravica (2,656 metres) in the Prokletije Mountains. Serbia is mostly a low-land country, up to 200 metres altitude (36.7 per cent of the territory) and up to 500 metres (61.3 per cent of the territory).[3]
Rain pattern	Serbia has a moderate continental climate with the maximum precipitation in May or June and October and minimum in February. Several parts of the country (southern, south-western) have Mediterranean pluviometric regimes (the maximum precipitation is in the winter months). The average annual precipitation ranges from 500 to 600 mm (Vojvodina and several river valleys), 600-700 mm (Posavina, Pomoravlje, lower parts of Šumadija and Carpatho-Balkanides), 700-800 mm in hilly areas and 800-1,100 mm in the mountainous areas.[3]
General dissipation of rivers and other water sources	The largest rivers are transit, international rivers (water discharge of the Danube at the exit of Serbia is about 5,500 m³/sec, Tisa 900 m³/sec, Sava 1,600 m³/sec, Drina 350 m³/sec), while the internal rivers are generally shorter and have lower discharges. The largest national river is the Velika Morava (175 km in length) with a discharge of 230 m³/sec. The total discharge of internal rivers is 480 m³/sec for the 1961-2010 period. Most abundant water areas (34.5 per cent of total runoff), with the highest precipitation and the lowest evaporation are located between 400-700 metres of altitude. The total capacity of existing groundwater sources is around 687 million m³ per year.[3]

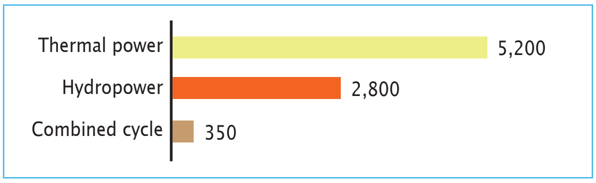
Electricity sector overview

The power system of Serbia has a nominal capacity of 8,350 MW: 5,200 MW from thermal power plants, 2,800 MW from hydropower plants and 350 MW from combined heat and power plants (Figure 1). Overall electricity generation in 2014 was 36,832 GWh with 25,297 GWh from thermal power plants, 11,472 GWh from hydropower plants, and 63 GWh from combined heat and power plants.[22] The electrification rate is 100 per cent. The annual electric power production by hydropower plants varies depending on the hydrological situation.[5]

In Serbia, 64 per cent of hydropower plants are run-of-river plants, 15 per cent are storage plants, and 21 per cent are reversible (pumped storage) plants. The power of thermal plants and run-of-river hydropower plants accounts for almost 90 per cent of the total capacity, while their share in electric power production is 95 per cent. These facts, as well as an extremely uneven consumption, lead to great difficulties in fulfilling consumers' needs for electric power during periods of peak consumption.[6]

FIGURE 1

Installed electricity capacity in Serbia by source (MW)



Source: Balkan Energy News[4]

Several factors have influenced the electricity sector in Serbia like the economic development accompanied with difficulties and major political changes have led to frequent changes of responsible institutions, laws and regulations and have made it impossible to monitor the planned developments. Also, the established legal framework has been subject to permanent improvement and harmonization with the legislation of the European

Union. One of the most significant steps was the implementation of the Water Framework Directive (Directive of European Parliament and of the Council 2000/60/EC). Also influential was the ratification of the treaty establishing the Energy Community, by which the Republic of Serbia agreed to adopt and carry out the plan for the implementation of Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources, to enforce a set of regulations on climate change aimed at reducing greenhouse gas emissions and to accede the International Renewable Energy Agency (IRENA).[7,8]

The point of departure highlighted in adopted strategic and planning documents is the conclusion that energy resources are not sufficiently explored, while available data is not conclusive. However, there is a general agreement that besides geological reserves of primary energy resources, hydropower potential and other renewable energy resources will be the basis for the development of production capacities in the future.

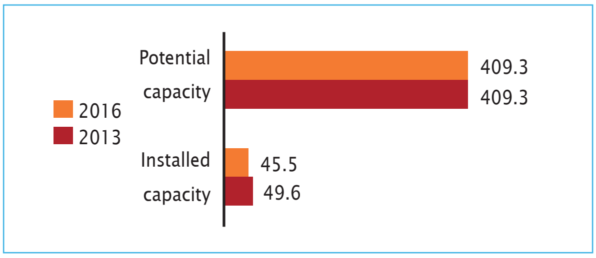
Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Serbia is up to 30 MW. Installed capacity of SHP up to 10 MW is 45.5 MW, while the potential is estimated to be 409.3 MW indicating that 11 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has decreased by approximately 8 per cent (Figure 2).

Since the adoption of the Decree on Incentive Measures for Privileged Electric Power Producers in January 2013, the term 'small hydropower' plants has been extended to include hydropower plants with the installed power up to 30 MW.[9] Until December 2012, this term covered all hydropower plants with the installed power up to 10 MW regardless of their type (i.e. it included both plants using reservoirs and run-of-river hydropower plants). The hydropower plants with the installed power up to 100 kW are called micro energy plants.[10]

FIGURE 2

Small hydropower capacities 2013-2016 in Serbia (MW)



Sources: *WSHPDR 2013*,[16] Ministry of Mining and Energy of Republic of Serbia[9]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

In Serbia, hydropower potential is considered the most important renewable resource and it is estimated at 27.2 TWh per year; technically feasible potential reaches 19.8 TWh per year, 18 TWh per year of which can be produced by hydropower plants larger than 10 MW. Currently 15 large hydropower plants produce 11.7 TWh per year.[11] The potential of small watercourses suitable for installing SHP plants is up to 0.4 million tonnes of oil equivalent or 3 per cent of the total potential of renewable sources in Serbia.[6] So far, 88 SHP plants up to 10 MW have been built on the rivers in Serbia. Out of that number, 50 (four in 2015) with a total capacity of 36.80 MW and an annual electricity production of approximately 200 GWh are operational and 38 facilities with a total capacity of 8.67 MW are out of use.[13,14] In 2013, Electric Power Industry of Serbia (EPS) bought energy from 33 SHP plants, while in 2014 EPS bought from 41 SHP plants that had the status of privileged producers. The electricity acquired from the privileged producers reached a total of 147 GWh.[15] A survey of 38 municipalities with the biggest potential for construction of SHP plants includes 711 locations with a potential of 409.3 MW (1,459 GWh/year).[16]

The government of the Republic of Serbia supports trends aimed at increasing hydropower generation capacity; it has defined three priorities: modernization and upgrading of existing hydropower plants, construction of new facilities and encouraging the development of the SHP sector. According to the National Action Plan for Renewable Energy Sources, it is planned that by new power plants with a total installed capacity of 1,092 MW will be erected by 2020.[17] So far, the Ministry of Mining and Energy has published two public calls for the allocation of sites for construction of SHP plants. In the past two years the State has offered investors 450 locations for the construction of small hydroelectric power plants. As a result of the first call, memoranda were signed for 212 locations (from 317 offered) with 90 investors in 17 municipalities of Serbia. Investors have shown great interest in the second Notice of available locations. The applications were submitted by 74 investors for 106 locations, while the interdepartmental commission proposed that the 40 investors signed a tripartite memorandum of understanding on 79 locations. The tripartite memorandum should be signed between the Ministry of Mining and Energy, local governments and investors.[18]

Projects for construction of SHP plants are constantly under consideration. It is believed that a significant number of approved projects will be completed by 2020. Also, it is planned to revise the Survey of Small Hydropower Plants in the Republic of Serbia (without the autonomous provinces) and the Survey of Small Hydropower Plants in Vojvodina. However, until the new surveys are completed and the data updated, these documents remain the key data concerning the future development and construction of SHP plants in Serbia. According to these documents, the greatest hydro potential usable for SHP is located in the west (in the Kraljevo and Užice regions) and south (the Niš region) of Serbia, which are mountainous areas. The greatest number of such facilities could be installed in the region where the first SHP plant in Serbia was built—in the Užice region. In the northern, flatland area of Serbia (Podunavlje, Vojvodina, the Belgrade area), hydropower potential is somewhat lower but these regions are the most densely populated and economically most developed parts of Serbia.[11]

According to the Energy Law of the Republic of Serbia, one of the main goals is to increase the share of renewable energy sources in energy production.[4] Along with the documents dealing with new facilities, there are numerous studies which draw attention to the revitalization of old SHP plants and the complementary utilization of other water management facilities for energy production. For example, the reconstruction and adaptation of the sites where water-mills were constructed in the past (according to estimations, there are about 5,000 such locations in Serbia), it would be possible to provide 10 MW of installed power, i.e. about 45 GWh of generated electricity per year. However, technical documentation for these facilities is lacking and it would be very difficult to assess investment possibilities.[5] Also, the Spatial Plan of the Republic of Serbia foresees the drafting of the investment-related and technical documentation and the implementation of projects aimed at installing SHP plants on the existing accumulation dams and hydropower production facilities, as well as on the existing multi-purpose water management accumulation reservoirs.[19] Projects by the Electric Power Industry of Serbia and foreign partners are currently in progress to develop 10 SHP plants on the Ibar River, with a total capacity of 120 MW, an annual production of 453 GWh, and an investment value of 340 million EUR.[18]

As for small-scale investments, investors usually decide to cover part of expenses by bank loans. However, as the practice has shown, banks offer varying repayment conditions, which are particularly reflected in varying annual repayment interest rates. Also, the European Bank for Reconstruction and Development (EBRD) approved a loan of EUR 32.3 million to the Electric Power Industry of Serbia for the reconstruction of 15 SHP plants with a total capacity of 18 MW and the construction of two new SHP plants on existing dams. In the long term, the Electric Power Industry of Serbia plans new investments in renewable energy, related entirely to SHP.[20]

The Survey of Small Hydropower Plants in the Republic of Serbia (1987) and the Survey of Small Hydropower Plants in Vojvodina (1989) are not up-to-date, so they should be replaced with the new SHP Cadastre which will be financed from pre-accession funds (IPA 2013).

Renewable energy policy

The Energy Law of the Republic of Serbia (Official Gazette of the Republic of Serbia 145/2014) prescribes the energy policy objectives and the methods of its implementation. In a separate segment, it highlights issues related to renewable energy sources, pointing out that it is in the interest of the Republic of Serbia to utilize them. The Law regulates issues related to SHP plants, all types of licences and permits and their privileged position in the market, compared to other energy producers who sell energy under equal conditions; it also implies the right to subsidies (tax, tariff and other subsidies provided for by law), as well as incentive feed-in tariffs.[21] Also, it is characterized as a law that will allow an increase in investments in the energy sector and incorporation of the EU acquis into the legal system of the Republic of Serbia. Following the adoption of the new laws, the Government plans to adopt new bylaws, including model contracts to purchase electricity from privileged producers.

The National Action Plan for Renewable Energy Sources (Official Gazette of the Republic of Serbia 53/2013), adopted in 2013, encourages investment in renewable energy sources, and sets the goals for utilizing renewable energy sources and their implementation by 2020. This document is the result of international commitments of the Republic of Serbia as a member of the Energy Community.[17]

Other legal acts, which specifically regulate the functioning of SHP plants and provide the necessary guidelines for investors were adopted in 2009 (Decree on the Requirements for Obtaining the Status of a Privileged Electric Power Producer and the Criteria for Assessing the Fulfilment of these Requirements; Model Agreement on Purchasing Electric Power from Privileged Producers) and in 2013 (Decree on Incentive Measures for Privileged Electric Power Producers), according to the previous Energy Law (Official Gazette of the Republic of Serbia 84/04, 57/2011).

The Spatial Plan of the Republic of Serbia from 2010 to 2020 (Official Gazette of RS 88/10) governs the spatial development of the Republic of Serbia. The Plan provides an overview of the available hydropower potential of Serbia and also deals with potential locations where SHP plants could be built in the territory of Serbia, taking into account documents such as the Survey of Small Hydropower Plants in the Republic of Serbia (1987) and the Survey of Small Hydropower Plants in Vojvodina (1989) and it also suggests that such locations be protected against unplanned usage.[19]

The Survey of Small Hydropower Plants in the Republic of Serbia (1987) and the Survey of Small Hydropower Plants in Vojvodina (1989) are still used as supplemental documents in the process of choosing potential locations for the construction of SHP plants. According to these documents, 869 locations were identified. The results of fifteen recently completed preliminary feasibility studies show, under the present economic conditions, it would be possible to use 5-10 per cent of the total locations foreseen by the Surveys.[12]

The Decree on Incentive Measures for Privileged Electric Power Producers (Official Gazette RS 8/2013), determined privileged purchase prices of electricity from SHP plants (Table 1).[9]

TABLE 1

Feed in tariffs for small hydropower

Categories of SHPs	Installed power (MW)	Incentive measures – pretax price (EUR/kWh (US$/kWh))
Newly built facilities	< 0.5 MW	0.097 (0.109)
Newly built facilities	From 0.5 to 2 MW	~0.0103 (0.012)
Newly built facilities	From 2 to 10 MW	0.0785 (0.088)
Existing infrastructure	< 2 MW	0.0735 (0.083)
Existing infrastructure	From 2 to 10 MW	0.059 (0.066)

Source: Ministry of Mining and Energy of Republic of Serbia[9]

Barriers to small hydropower development

Although the idea of installing SHP plants in Serbia emerged in the early 20th century and was followed by the construction of several dozens of such facilities, more recent political and economic changes caused a significant delay in their development compared to other countries. Relevant legislation and planning documents seek to promote a more intensive exploitation of the energy source due to its advantages. However, there are numerous limiting factors that hinder and impede it.

Country-specific barriers:

- Complicated permit-issuing procedures (about two years to complete);
- Great initial investment (costs of preliminary and main project drafting);
- Limited funds for investing in projects in this area;
- No updated versions of the Survey of Small Hydropower Plants in the Republic of Serbia (1987) and the Survey of Small Hydropower Plants in Vojvodina (1989);
- Low awareness of the advantages of SHP both among professionals and the public;
- Insufficient knowledge of technologies, economic and ecological indicators;
- Payback time estimation.

4.3.9 Slovenia

Saso Santl, Institute for Water of the Republic of Slovenia

Key facts

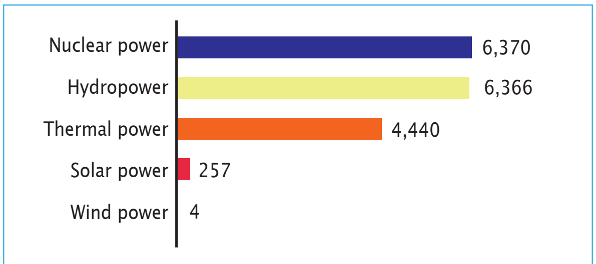
Population	2,062,874[1]
Area	20,273 km^2
Climate	The climate is continental with cold winters and warm summers, but at the coastal areas there is a pleasant sub-Mediterranean climate. The average temperatures are 0°C in January and 20°C in July.[2]
Topography	The topography of the Slovenian territory is mostly elevated. Outside the coastal area, the terrain consists largely of karstic plateaus and ridges, alpine areas with mountain and hill chains, basins and valleys and also river lowlands in the south-east. The highest Alpine peak is Triglav (2,864 metres).[2]
Rain pattern	On the global scale, Slovenia exhibits above average precipitation abundance. The average rainfall is 1,000 mm at the coast and up to 3,500 mm in the western areas of the Alps, 800 mm in the south-east and 1,400 mm for central Slovenia. Plentiful snow falls in winter (December – February). The driest months are December to March, while June and November receive more than 130 mm on average.[7]
General dissipation of rivers and other water sources	The average measured runoff in Slovenia is 27 l/sec/km^2, which is equivalent to around 588 m^3/sec of net runoff from the territory. The Mura and the Drava transit streams (from Austria) have an average annual runoff around 418 m^3/sec and the total average runoff from Slovenian territory is around 1,006 m^3/sec.[6]

Electricity sector overview

Average gross electricity production for the period between 2010 and 2014 was 16,300 GWh per annum. In 2014, total electricity generation was at 17,437 GWh including 6,370 GWh from nuclear (36.5 per cent), 6,366 GWh from hydropower (36.5 per cent), 4,440 GWh from thermal (25.5 per cent), 257 GWh from solar (1.5 per cent) and 4 GWh from wind (0.02 per cent) power plants (Figure 1).[1] Total installed capacity in 2014 was 3,453 MW, out of which 1,295 MW was from hydropower, 1,242 MW from thermal, 688 MW from nuclear, 224 MW from solar and 4 MW from wind power.[1]

FIGURE 1

Electricity generation in Slovenia by source (GWh)



Source: Statistical Office, Slovenia, 2015[1]

A reform of the energy sector came with the adoption of the new Energy Act in 2014.[3] The reform was needed to implement the European Union (EU) directives that had been adopted after the previous law was enacted, as well as to bring the law into compliance with decisions of the Slovenian Constitutional Court, which had declared the previous law unconstitutional in relation to certain aspects of the determination and calculation of network charges. The law lays down the principles of energy policy, energy market operation rules, manners and forms of providing public services in the energy sector, principles and measures for achieving a secure energy supply, improving energy efficiency and energy saving and increasing the use of energy generated from renewable energy sources. In Slovenia, the Energy Agency is the market regulator and is responsible for the transparency of market operations, determining methodologies for the energy sector, issuing guarantees of the origin of electrical energy and commercial green certificates for the production of electricity from renewable energy sources (RES). Borzen is the market organizer with the main task to promote the development of the Slovenian electricity market and market mechanisms in accordance with EU guidelines and contributes significantly to the proper functioning of the Slovenian power system, as well as aligning the Slovenian and EU legislation and integration of the Slovenian electricity market into the integrated European electricity market.

In Slovenia, large electricity producers and transmission/distribution systems are owned by the State. The activities of electricity transmission and distribution are mandatory national public services carried out by the electricity system operators that are also owned by the State. Small electricity producers (up to 10 MW), distribution companies and energy market suppliers can be publicly or privately owned, or as a public-private partnership (PPP). The total length of electric transmission network in Slovenia is 2,852 kilometres and connects major producers, big consumers and neighbouring countries (Austria, Croatia and Italy). The total length of the distribution network is around 65,000 kilometres (70 per cent is low-voltage network), which also includes street lighting and by which the Slovenian territory is efficiently covered for existing small producers. Domestic energy production covers more than 90 per cent of the Slovenian electricity demand.[5] The total number of electricity consumers is around 935,000, of that around 89 per cent are household consumers, and the electrification rate is 100 per cent. The biggest consumers of electricity (56 per cent) are industry and enterprises, 25 per cent is households, 16 per cent transmission-network consumers and 3 per cent is pump storage for the accumulation of water.[5] Based on monthly consumption, there are no significant seasonal fluctuations. Considering the implementation of measures for efficient energy use, overall energy consumption should increase by less than 5 per cent and gross electricity consumption should increase by less than 10 per cent in Slovenia by 2020.[8] Major challenges with the increase of electricity production from RES, especially from hydropower, are finding proper harmonization and balance with legitimate environment and nature preservation objectives; this requires more thorough collaboration between relevant competent authorities in the process of strategic decision making. To define and harmonize the strategic energy development of Slovenia, the Energy Concept of Slovenia is being prepared and is planned to be adopted in 2016. The main objectives of the document are a significant reduction of greenhouse gas emissions in the field of energy production (at least by 80 per cent by 2055) while taking into consideration sustainability, climate acceptability, supply reliability and competitiveness.[15]

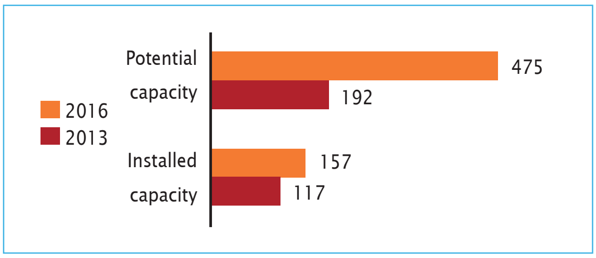
Since the full opening of the market on 1 July 2007, the price of electricity supply has become the market value. So electricity prices for general industrial and household consumers in Slovenia are dependent on the wholesale market in Slovenia and in the EU.[16] The average electricity price for households in Slovenia at the end of 2014 was EUR 0.158/kWh (US$0.18/kWh) and for industry without value added tax EUR 0.089/kWh (US$0.1/kWh).[5] EU and Slovenian regulations support electricity production from RES and also consider high efficiency cogeneration. However, support is granted only for generating plants whose electricity generating costs exceed the price of electricity in the open electricity market. By the end of 2014, there were roughly 3,700 power plants included in the scheme, predominantly hydropower and photovoltaic (PV) ones. The total installed capacity is about 500 MW. Support is defined annually for new production and for up to 15 years, and can comprise guaranteed purchase of electricity or financial aid (operating support) for current operation. RES generating plants with nominal capacity of 5 MW and more are eligible only for the latter support option.[4]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Slovenia is up to 10 MW. Installed capacity of SHP is 157 MW: 119 MW of plants up to 1 MW and 38 MW of plants from 1 MW to 10 MW.[1] According to overall estimations, in Slovenia there are around 2,000 MW of theoretical, 1,100 MW of technical, and 475 MW of economic potential for electricity production from SHP up to 10 MW of installed capacity.[11] Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, Slovenia has witnessed an increase in both installed capacity and potential capacity of SHP (Figure 2).

FIGURE 2

Small hydropower capacities 2013-2016 in Slovenia (MW)



Sources: Statistical Office RS,[1] *WSHPDR 2013*[13]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

However, there are different definitions of SHP in Slovenia. From the point of water management SHP is defined as a hydropower plant (HPP) with installed capacity less than 10 MW. From the point of energy production from RES there are four categories divided by size:

- Micro: less than 50 kW;
- Small: between 50 kW and 1 MW;
- Medium: between 1 and 10 MW;
- Large: more than 10 MW.

In 2014, there were 460 SHP plants operating and selling electricity to the grid. The number of water rights was higher (509), the difference is due to the fact that some are not operating, are under construction, produce electricity for own supply, or more than one water right is granted for the same SHP plants (split of electricity production/potential among the owners). The installed capacity is 157 MW and electricity production for the year 2014 was 496 GWh (246 GWh from plants up to 1 MW and 250 MW from plants from 1 MW to 10 MW).[1] 2014 was a rainy year; average for the period between 2004 and 2014 was around 385 GWh/annum.[19] In comparison to electricity production from large HP in 2014 (around 5,870 GWh), the share of SHP is around 7.8 per cent of total electricity production from hydropower.[1]

Renewable energy policy

The main strategic action plan concerning RE in Slovenia is the National Renewable Energy Action Plan 2010-2020 (NREAP); it plans 25 per cent of RES in the final energy consumption by 2020. It also covers the national policy of renewable energy sources, expected gross final energy consumption in the period between 2010 and 2020, targets and trajectories regarding renewable energy sources, measures for achieving binding target shares of renewable energy sources and estimation of the contribution of individual technologies to achieving the target shares of renewable energy sources, the costs of carrying out measures and impacts on the environment and job creation.

The objectives of the national energy policy for RES are ensuring a 25 per cent share of RES in final energy consumption and a 10 per cent share of renewable energy in transport by 2020. In order to achieve these objectives, the NREAP states measures to be implemented for sectors of heating and cooling, electricity and transport. The competent authority for energy is the Energy Directorate within the Ministry of Infrastructure (previously within the Ministry of the Economy). In the measure Proactive Role of the State in Identifying Environmentally Acceptable Locations for Exploiting RE Potential, it is stated that the Ministry of the Environment and Spatial Planning will ensure the processing of already received petitions for initiating the procedure for allocating water rights for SHP plants, and the Ministry of Economy will provide a study of the costs and benefits of existing SHP plants, as a basis for sustainable criteria, wherein it takes account of environmental, social and economic impacts.[8]

In general, the support for hydropower development in Slovenia is mixed. Comprehensive studies, such as the preparation of a master plan to define possible locations that are also harmonized especially with environmental objectives, are necessary to be prepared and adopted between sectors. This need has been widely recognized and already supported by numerous studies and documents.[10,12,14,18,19,20] It is important to raise the acceptance of SHP, but for those which can on one side produce not just renewable energy but also green energy, it requires full mobilization of mitigation measures to minimize negative effects on aquatic ecosystems and water status and also to support other water management related benefits.

Legislation on small hydropower

According to the National Renewable Energy Action Plan 2010-2020 for SHP, the target capacity for foreseen for SHP plants of capacity 1-10 MW is 57 MW and for smaller SHP plants 120 MW.[8] Thus, the total capacity of SHPPs is planned to reach 177 MW by 2020. A major challenge is to harmonize RES and ecological objectives, so the activities for identifying environmentally acceptable locations for exploiting hydroelectric potential have been started. The sites are prepared according to the guidance for Alpine Space and Danube Basin with consideration of Article 4.7 of the Water Framework Directive and Article 6.4 of the Habitats Directive. The Water Framework Directive and also the Habitats Directive state that public interest must be taken into account and the benefits of new electricity production must outweigh environmental benefits.[3,20] The main principle to be followed is that the higher the ecological value of a water stretch (water body) the higher the energy output must be. Therefore, the planning of hydropower favours larger hydropower plants; SHP plants as a rule are foreseen on already deteriorated stretches with a focus on optimization of existing exploitation as well as where multipurpose benefits are foreseen (e.g. flood protection, irrigation etc.).

In 2015 not many new SHP plants were planned in Slovenia; the most common were SHP projects on already existing water objects (e.g. construction of an SHP plant with installation of Environmental Flow instead of spilling it over the weir gates). There are currently more than 40 applications for water rights granting new SHP development at the Slovenian Environmental Agency. The last comprehensive analysis and planning of possible SHP projects on the national scale was done in 2007, where 33 SHP plants with capacity of 1-10 MW and 6 SHP plants with lower capacity were foreseen.[9] Most of the locations of foreseen SHP plants were not harmonized with the Water Framework Directive (e.g. they are planned on reference river stretches) or were planned in protected areas outlined in the Natura 2000 EU framework.

In Slovenia, financial support to SHP development is provided by supporting schemes. As mentioned previously, two types of support are possible: operating support (OS) and guaranteed purchase (GP) which are provided for a period of 15 years for new projects. The levels of support are defined each year and do not affect plants which are already included in the supporting scheme. The tariffs for 2015 are detailed in Table 1.[4]

TABLE 1

Tariffs for hydropower plants (US$/MWh)

Support scheme	Micro hydro (< 50 kW)	Small hydro (50 kW-1 MW)	Medium hydro (1 MW-10 MW)	Large hydro (< 250 MW)
Operational support	80.28	65.81	52.48	45.99
	Micro hydro (< 50 kW)	**Small hydro (50 kW-1 MW)**	**Medium hydro (1 MW-5 MW)**	
Guaranteed purchase	118.63	104.17	92.62	

Source: Borzen [4]

Barriers to small hydropower development

Although developed evaluation methods are in place on how to proceed with the analysis of available potential and how to balance different objectives, collaboration between sectors responsible for different objectives is poor. Each sector follows its own objectives and they do not properly apply the principles of sustainable development, which impedes the framework for managing resources and coordinating and integrating environmental, economic and social aspects in an equal way.

In Slovenia the water management sector is inadequately supported by human and financial resources due to significant reductions in the last 25 years (especially compared to the growth of national GDP in that period). That is reflected in poor data management, lack of supervision and a stronger position of water management objectives in spatial planning and land use, inadequate maintenance of water infrastructure and watercourses and also in unclear and un-straightforward decision making. The State administration of the water sector has also been periodically reorganized, mostly following disastrous events (e.g. floods). There is a need for:

- Better data generation and harmonisation
- Improved stakeholder involvement and communication
- Integration of the ecosystem service concept
- Implementation of strategic (spatial) planning approaches on various spatial levels

It should also be mentioned that especially in the environmental protection sector there is mistrust for new SHP development, since many of the existing SHP operators do not follow the obligations for ensuring environmental flow and other aquatic ecosystem protection issues.

One of the barriers for planning financially feasible and state-of-the-art SHP plants is inadequate technical, economic, environmental and risk awareness on the investor side, especially the smaller ones, who are not aware that investment in SHP with full consideration of all technical, safety and environmental aspects can require considerable time and financial resources.

4.3.10 Spain

Cayetano Espejo and Ramon Garcia, Universidad de Murcia; Nathan Stedman, International Center on Small Hydro Power

Key facts

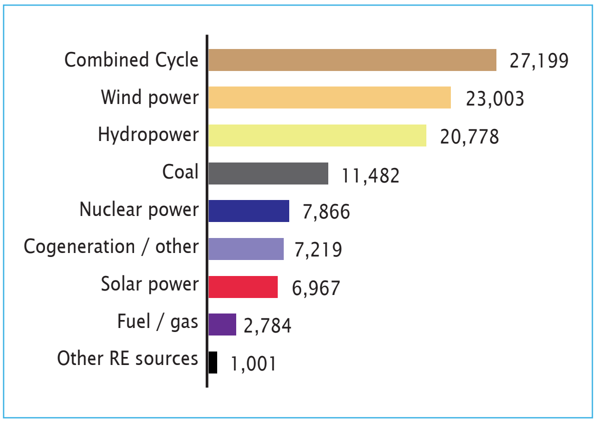
Population	46,404,602[6]
Area	505,000 km^2
Climate	Temperate climate; summers are clear and hot in the interior of the country and more moderate and cloudy along the coast; winters are cloudy and cold in the interior and partly cloudy and cool along the coast. Average temperatures range between 6.6°C in January and 22°C in July.[7]
Topography	Large, flat to dissected plateau surrounded by rugged hills with average height of 610 metres above sea level. In the north the Pyrenees stretch approximately 400 km from the Atlantic coast; the mountains of the Cordillera Betica and Sierra Nevada transverse the far south. The highest point of mainland Spain is Mulhacen at 3,481 metres above sea level.[8]
Rain pattern	Average annual precipitation is 650 mm. In northern Spain rainfall reaches 1,000 mm, while in semiarid areas it is only 300 mm. The driest months are June to September, while the wettest is November, with an average of 73 mm.[7]
General dissipation of rivers and other water sources	There are around 1,800 rivers in Spain, though many stay dry for much of the year. When filled with water, rivers quickly turn into raging and destructive torrents. Five major rivers follow the direction of the major mountain systems with four of them flowing into the Atlantic (the Duero, Tagus, Guadalquivir and Guadiana) and one (the Ebro) into the Mediterranean. All these rivers all dammed, as well as many of their numerous tributaries, and the reservoirs provide much of the water and electrical power for the country.[8]

Electricity sector overview

Spain (the Iberian Peninsula and the isolated island network also known as the Balearic and the Canary islands as well as Ceuta and Melilla) has a total installed capacity of 108,299 MW (2015), comprised of 19 per cent from hydropower, 25 per cent from combined cycle gas turbine plants, 21 per cent from wind power, 11 per from cent coal-fired plants, 7 per cent from nuclear, 7 per cent from cogeneration, 6 per cent from solar, 3 per cent from fuel and gas-fired plants, and 1 per cent from renewable based thermal power (Figure 1).[1]

FIGURE 1

Installed electricity capacity in Spain by source (MW)



Source: Red Electrica de España[1]

The net demand in 2015 was approximately 263,094 GWh, up almost 2 per cent from 2014. Also in 2015, Spain generated 268,057 GWh, indicating an increase of 0.4 per cent from 2014. Hydropower production accounted for 31,396 GWh.[1]

The Ministry of Industry, Energy and Tourism (Minetur) is responsible for formulating and implementing energy policy. The regulator for the energy sector is the National Commission of Markets and Competition (CNMV). The CNMV also cooperates with other regulators through the Council of European Energy Regulators (CEER) and the Agency for the Cooperation of Energy Regulators (ACER) for interconnections between neighbouring countries.[10]

In terms of installed capacity, the largest companies are Iberdrola, Endesa and Gas Natural Fenosa, which together control about 75 per cent of the capacity.[10]

The Spanish wholesale market is part of the Iberian power market (Mercado Ibérico de Electricidad – MIBEL) which includes both Spain and Portugal. OMIE in Spain manages the spot market while OMIP in Portugal manages the futures market. Red Eléctrica de España (REE) and Red Eléctrica Nacional (REN) are the two system operators.[10]

The Spanish transmission network is owned and operated by REE. In 2013, the transmission network had a total length of 40,000 km, of which 20,641 km was at 400 kV and included 5,216 substations with a transformer capacity of 80,695 MVA.

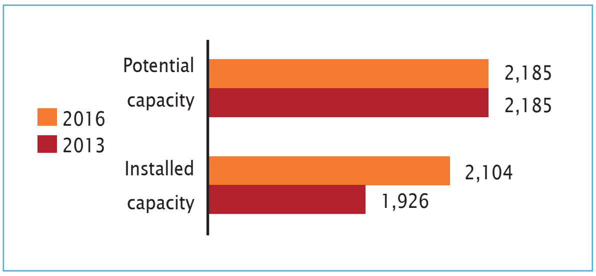
Endesa, Iberdrola, Gas Natural Fenosa, E.ON and HC Energia-EDP are the five major distributors. However, there are more than 300 smaller companies that also provide distribution services.[10] The electrification rate in Spain is 100 per cent.

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Spain is an installed capacity up to 10 MW. The SHP installed capacity is 2,104 MW from 1,091 plants. The SHP potential is 2,185 MW.[2,4] Between *World Small Hydropower Development Report (WSHPDR) 2013* and *WSHPDR 2016*, installed capacity has increased by 178 MW and the SHP potential remained the same. The increase in installed capacity is due to new installations, refurbishments of existing SHP plants, as well as access to more accurate data.

FIGURE 2

Small Hydropower capacities 2013-2016 in Spain (MW)



Sources: *WSHPDR 2013*,[5] Garcia y Espejo,[2] Comision Nacional del Mercado de Valores[4]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Most of the SHP plants are located in the north of Spain, in the regions where the larger number of river basins with more hydropower resources are located. SHP plants, due to the favourable administrative and legal framework, have considerably increased their capacity since the early 1990s, especially in the Galicia region where the SHP installed capacity has increased by more than 50 per cent (Table 1).[3]

From 1998 to 2014, the number of SHP plants has increased by 62.6 per cent and the SHP installed capacity has increased by the same percentage. The SHP plants have an important impact on the Spanish economy. In 2013, the SHP industry contributed EUR 518 million (US$571 million) to the national GDP.

The total theoretical hydropower potential in Spain is 162,000 GWh/year, the technically feasible potential is 61,000 GWh/year and the economically feasible potential is 37,000 GWh/year. The SHP potential generation has been estimated at 7,500 GWh/year.[4]

TABLE 1

Installed small hydropower capacity by region (MW)

Region	Installed capacity (MW)			
	1998	2005	2010	2014
Andalucía	75.0	99.0	143.0	143.0
Aragón	150.0	255.0	254.0	257.0
Asturias	111.0	77.0	77.0	77.0
Canarias	0.5	0.5	0.5	0.5
Cantabria	60.0	67.0	71.0	72.0
Castilla-La Mancha	55.0	96.0	128.0	126.0
Castilla y León	128.0	207.0	246.0	256.0
Cataluña	192.0	264.0	278.0	286.0
C. Valenciana	7.0	31.0	31.0	31.0
Extremadura	13.0	20.0	20.0	23.0
Galicia	258.0	371.0	493.0	522.0
La Rioja	19.0	23.0	27.0	27.0
Madrid	63.0	63.0	44.0	44.0
Murcia	11.0	12.0	14.0	14.0
Navarra	104.0	116.0	151.0	171.0
País Vasco	50.0	65.0	53.0	54.0
Total	**1,296.5**	**1,766.5**	**2,030.5**	**2,103.5**

Source: Comision Nacional del Mercado de Valores[4]

Renewable energy policy

The resurgence of the SHP sector was due to the Government's support of the producers of renewable energy. The Electricity Sector Law (54/1997) set a special regulation for sources of renewable energy with an installed capacity lower than 50 MW. Furthermore, the Law recognizes the environmental benefits of these sources by granting financial benefits. Therefore, renewable energy sources can compete with traditional sources of energy.[1]

The Royal Decree 436/2004 of 12 March 2004, as developed upon the Electricity Sector Law, set the legal and economic framework for the Special Regime, 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. This decree set a new system aimed at renewable energy plants in order to achieve the targets of the Renewable Energy Plan 2005-2010.

The Spanish economic crisis, alongside the increase of tariffs, has led to the adoption of a series of contentious measures against renewable energy, 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.

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 coming from renewable energy sources, cogeneration and waste.

Legislation on small hydropower

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 the 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. Plants with a rated power less than 10 MW as well as those with a rated power greater than 10 MW (but less than 50 MW) were considered small-scale hydropower plants. 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 (RES-E).[1] The move was a result of a tariff deficit of roughly EUR 26 billion (US$28.7 billion) in 2012, which was largely driven by the incentives to renewable energy sources.[10]

The 2014 Royal Decree 413/2014 (RD 413/2014) replaced renewable energy feed-in tariffs with a “reasonable 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.[10]

Barriers to small hydropower development

Although SHP has played an important role in electricity generation in the country, SHP development, particularly since the tariff deficit, currently faces several barriers:[3]

- Some potential hydropower sites have not been studied in detail, thus, there is a lack of knowledge regarding their actual potential.
- In order to use water for hydropower purposes, licences need to be issued which requires an environmental authorization approval; the excessive waiting time to get approvals slows the development of potential projects.
- Difficulties in renewing the water concession periods of the current hydropower plants. This could lead to the abandonment of some existing SHP plants.
- The administrative process to get a licence is complex, even for small projects.
- There are obstacles in the procedure of getting authorization from regional and local organs.

4.3.11 The former Yugoslav Republic of Macedonia

Viktor Andonov, Ministry of Economy of the Republic of Macedonia

Key facts

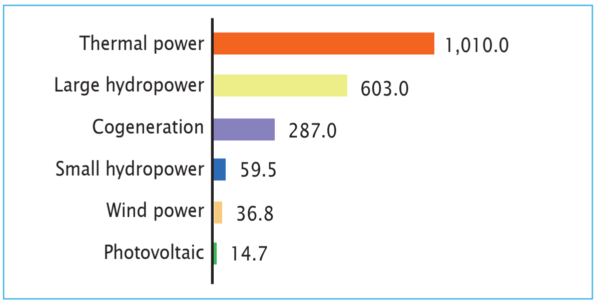
Population	2,075,625[1]
Area	25,713 km^2 [1]
Climate	Macedonia has a transitional climate from Mediterranean to continental. Warm and dry in the summer and autumn months between June and October with July and August being the warmest when, in some regions, the temperature exceeds 40°C. The country is relatively cold with heavy snowfall during the winter months between December and February. Average temperatures range between approximately 20°C in July and August to less than 0°C in January.[2]
Topography	Macedonia is a land-locked country framed along its borders by mountain ranges and with a central valley formed by the Varda River. The region is seismically active and has been the site of destructive earthquakes in the past. The highest point is Mount Korab at 2,764 metres.[3]
Rain pattern	Average annual precipitation varies between 1,700 mm in the western mountainous regions and 500 mm in the east. The wettest months tend to be November and December as well as April and May.[2]
General dissipation of rivers and other water sources	The Vardar is the longest and most important river in Macedonia bisecting the country and forming a central valley. It is 388 km long and drains an area of approximately 25,000 km^2. There are also three large lakes: Ohrid, Prespa and Dojran.[3]

Electricity sector overview

Electricity production in Macedonia is mainly from lignite and large hydropower. In 2014, total installed capacity was 2,011 MW consisting of: thermal power plants (50 per cent), large hydropower (30 per cent), combined heat and power plants (14 per cent), wind (2 per cent), small hydropower (SHP) (3 per cent) and photovoltaic (1 per cent) (Figure 1). This represents an increase of approximately 3 per cent compared to 2013.[1]

FIGURE 1

Installed electricity capacity in Macedonia by source (MW)

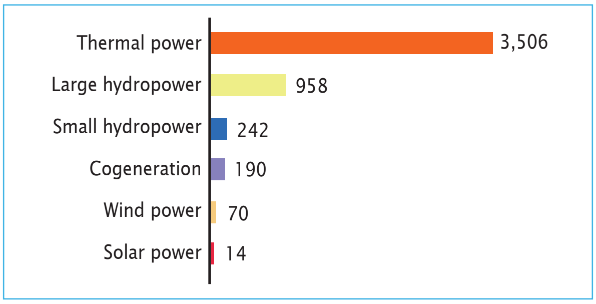


Source: ERC (2014)[4]

In 2014, total electricity generation was 4,980 GWh. Thermal power plants contributed 3,506 GWh, large hydropower 958 GWh, wind 70 GWh, combined heat and power plants 190 GWh, SHP 242 GWh, and photovoltaic, 14 GWh. Macedonia is also dependent on imports of electricity, largely from Hungary, Romania, Bulgaria, Serbia and Bosnia. In 2014, 38 per cent of electricity (3,032 GWh) was imported (Figure 2).[4]

FIGURE 2

Annual electricity generation in Macedonia by source (GWh)



Source: ERC (2014)[4]

The most important renewable resources in Macedonia are hydropower and biomass. Wind power is increasing with the first wind park, Bogdanci, having been commissioned, with a capacity of 36.8 MW installed in the first phase and a further 50 MW to be added in the second phase. Generation from solar power plants is also increasing however, due to the higher investment cost, the Government set a national limit of 18 MW and, with planned constructions, and this capacity has already been reached. Four biogas plants with a total installed capacity of 7 MW are planned to be put in operation in 2016-2017.[4]

Large hydropower plants (HPP) are very important for Macedonia with several planned projects underway:. HPP

Boskov Most (70 MW) and the storage power plant Lukovo Pole with Crn Kamen (160 GWh additional generation in the system). Other plans include: Cebren (333 MW), Galishte (200 MW), Gradec (54 MW) and Veles (93.3 MW).[5]

The electrification rate is close to 100 per cent although some remote areas still lack access to the grid. The distribution grid is operated by EVN Macedonia and according to the Law on Energy, it is responsible for the development and upgrade of the network. Grid codes define how consumers can request access to the grid.[1] Macedonia has implemented the Second EU Directive package which includes third party access. EVN Macedonia has announced that in the next 20 years they will invest EUR 1 billion (US$1.33 billion) in the modernization of the distribution grid.

The electricity sector of Macedonia consists of generation facilities, a transmission system, a distribution system and final consumers. The main electricity producer in Macedonia is the state-owned Joint Stock Company Macedonian Power Plants (JSC ELEM), which owns 90 per cent of total electricity production. The state-owned Joint Stock Company – Macedonian Transmission System Operator (JSC MEPSO) operates the transmission system while the market operator responsible for distribution is EVN Macedonia, which is 10 per cent state-owned with the remainder owned privately by EVN AG Austria. Two independent power producers (IPP), CHP TE-TO and CHP KO-GEL, are also present in the electricity market. EVN Macedonia also has SHP plants constructed between 1927 and 1953 in their portfolio, some of which have been renovated in the last several years. The country's photovoltaic plants are constructed and operated by private domestic and foreign investors.[7]

Macedonia is a candidate country for the European Union (EU) and a contracting party in the Energy Community. Thus, it is committed to applying the EU Community Acquis in domestic legislation. Accordingly Macedonia has been working on reforming the energy sector to achieve a single regional stable regulatory market framework capable of attracting investment in transmission networks and generation capacity as well as fostering competition and interconnectivity, thus ensuring supply and realizing economies of scale.

The electricity market in Macedonia is liberalized and at present more than 45 per cent of the total consumption is traded between the traders, suppliers and other market players. Although households and some small companies are still on the regulated market, they are expected to move to the open market by 2020. The Government was expected to update the laws on energy and implement the Third EU Energy Package on the internal energy market by 1 January 2015. However, the deadline was missed and as of June 2016, new legislation was not yet in place.[12] A project for strengthening the administrative capacities of the Energy Department in the Ministry of Economy and the Energy Agency of Republic of Macedonia was implemented in 2013 and 2015.

TABLE 1

Electricity tariffs for households in Macedonia

	Tariff (EUR (US$) per kWh)		
Tariff type	**2013**	**2014**	**2015**
Households subject to SINGLE-TARIFF metering	0.0692 (0.0922)	0.0728 (0.0970)	0.0727 (0.0968)
Households subject to TWO-TARIFF metering: peak tariff	0.0863 (0.1150)	0.0909 (0.1211)	0.0906 (0.1207)
Households subject to TWO-TARIFF metering: off-peak tariff	0.0433 (0.0577)	0.0455 (0.0606)	0.0454 (0.0605)

Source: ERC[4]

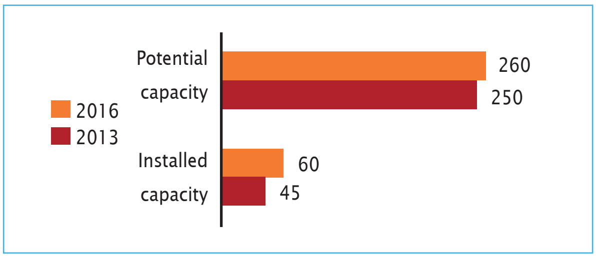
Macedonia has one of the lowest electricity tariffs for households in the region, and in Europe, ranging between EUR 0.0454 (US$0.0605) per kWh to EUR 0.0727 (US$0.0968) per kWh in 2015 (Table 1). The tariffs are set annually by the Energy Regulatory Commission and have been increasing incrementally year on year.[4]

SHP sector overview and potential

Macedonia defines SHP as plants with an installed capacity of 10 MW or less. In 2014, SHP installed capacity was approximately 60 MW (3 per cent of the total installed capacity) generating 242 GWh.[4] Potential capacity is estimated at 260 MW (Including at least 60 MW which will be constructed by 2018 according to obligations from concession agreements) indicating that 23 per cent of the country's SHP potential has been developed. Compared to data from *World Small Hydropower Development Report (WSHPDR) 2013*, installed capacity has increased by more than 30 per cent while estimated potential has increased marginally by 4 per cent (Figure 3).

FIGURE 3

Small hydropower capacities 2013-2016 in Macedonia (MW)



Sources: ERC,[4] *WSHPDR 2013*[8]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

SHP currently accounts for approximately 8.4 per cent of the total installed hydropower capacity and approximately 3 per cent of the country's total installed capacity. However, Macedonia has a significant potential for SHP development with more than 400 identified sites throughout the country which could potentially meet up to 16 per cent of the country's current electricity needs. The central study on SHP potential in Macedonia is the Feasibility Study for Small and Mini-hydropower produced in 1982 by the Faculty for Mechanical Engineering, Skopje

University. The potential for the installed capacity in the study is approximately 250 MW with individual capacities ranging from 50 kW to 5,000 kW.[9]

Renewable energy policy

The renewable energy policy of Macedonia is defined within the Law on Energy and the Strategy for Higher Utilisation of Renewable Energy Sources. The current share of renewable energy sources of total final energy consumption is 15.6 per cent and, according to obligations from the Energy Community, the target is 28 per cent by 2020.[5] However, some consider this to be too high, based on the inaccurate data provided on biomass potential. A survey by the State Statistical Office on energy consumption in households is underway that will give a more accurate account of biomass potential, after which the Government intends to request a revised target. At present, the Strategy for Higher Utilisation of Renewable Energy Sources is being updated for the period up to 2025.

In order to align its policies with the EU, the Government has made efforts to promote electricity production from renewable energy sources. Incentives are provided through feed-in tariffs (FIT) for the licensed producers of electricity with guaranteed purchase of the total amount of produced electricity for the period of using this preferential tariff. Renewable energy plants also have priority in dispatching by the market operator. The eligibility for application of FIT for SHP plants is an installed capacity up to 10 MW per plant and there is no national limitation on the number of SHP plants.[11]

The FIT proposed for wind power is for plants up to 50 MW while there is a total national installed capacity limit of 150 MW. For cogeneration plants using biogas and biomass, the national limit is set at 10 MW. This is primarily due to the relatively small potential of these renewable sources. For photovoltaic plants the national limit under the current FIT system is 18 MW with 4 MW assigned to plants with a capacity lower than 50 kW and 14 MW assigned to plants up to 1 MW. The Government sets FITs for all types of renewable energy sources except for geothermal energy.[11]

Legislation on small hydropower

SHP plants in Macedonia are constructed according to the Law on Waters and the Law on Concessions and Public Private Partnership.[10] Between 2007 and 2011, the Ministry of Economy of the Republic of Macedonia conducted five tendering procedures for granting water concessions for electricity production from SHP plants. The Ministry of Economy signed 66 concession agreements with 23 concessioners, both foreign and domestic, with a combined installed capacity of 60 MW and estimated annual production of 240 GWh. The level of investment is expected to be between EUR 120 and 150 million (US$150 million To US$200 million).

In 2011, the Ministry of Environment and Physical Planning became responsible for granting water concessions for constructing SHP plants. In 2014, they conducted the sixth procedure for granting water concessions for electricity production from SHP plants and in 2015, they signed concession agreements for constructing 19 SHP plants with a total installed capacity of 23 MW. The concession agreements are signed for a period of 23 years from which 3 years is given to obtain all the necessary licences and carry out the construction work. The concessionaires will produce electricity for a period of 20 years with guaranteed purchase by the market operator.

With these signed agreements for concessions, alongside public private partnerships, it is estimated that Macedonia will have approximately 100 newly constructed SHP plants with an approximate installed capacity of 100 MW by 2019.

TABLE 2

Feed-in tariffs in Macedonia for small hydropower plants by capacity

Produced electricity per month (kWh)	FIT (EUR (US$) per kWh)
≤ 85,000	0.12 (0.16)
> 85,000 and ≤ 170,000 kWh	0.8 (1.07)
> 170,000 and ≤ 350,000 kWh	0.6 (0.80)
> 350,000 and ≤ 700,000 kWh	0.5 (0.67)
> 700,000 kWh	0.45 (0.60)

Source: Energy Regulatory Commission[11]

The Government of the Republic of Macedonia has supported the construction of SHP plants as a renewable energy source, including the introduction of feed-in tariffs in 2007. The tariff is a declining tariff based on monthly electricity production (Table 2). The Government has also signed several direct agreements with the European Bank for Reconstruction and Development (EBRD) for supporting their loan agreements with several concessionaires. This possibility is given to all investors who signed the agreements and are seeking loans from different financial institutions.[11]

Barriers to small hydropower development

One of the most critical issues concerning the development of SHP plants in the future is the need for accurate hydrological data taken over an extended period of time, as some previous estimates of potential capacity have been criticized for overestimating the volume of water at some sites. Connection to the distribution grid is another crucial issue. Most of the potential SHP locations are in rural areas with either no connection or no stable, quality network. This means that the investment cost of grid connection is often very high. In the last several years a number of laws and sub-laws were amended in order to streamline the procedures for obtaining construction permits. However, another key challenge in the future is to establish a single authority for all the procedures, licences and permits in order to reduce the time needed to realize these projects.

4.4 Western Europe

Miroslav Marence, UNESCO-IHE

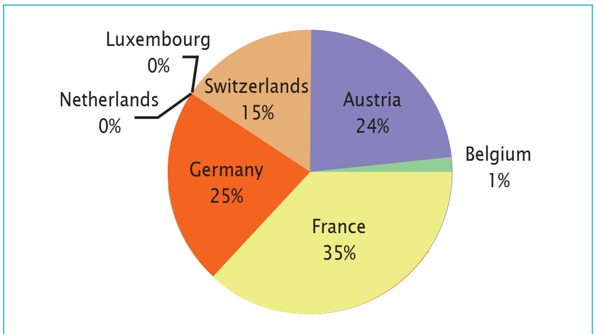
Introduction to the region

Western Europe includes nine countries, seven of which use small hydropower (SHP) (excluding Monaco and Liechtenstein). The geographic characteristics of the region can be characterized as mountainous in the south and south-east (Alpine region), over hilly uplands into broad low plants on the north and north-west, with a small part of Mediterranean in south-west. The dominant climate is continental and temperate, with a maritime climate on the coast.

All countries of Western Europe have 100 per cent access to the electricity. As a part of the European market of the electrical transmission grids, all of these countries are strongly connected and working together under the coordination of ENTSO-E, the European Network of Transmission Systems. The national electrical grids, integrated in a cross-border electricity market, are challenged not to produce enough energy, but to secure and stabilize the whole European grid under very rigorous criteria for grid variation in frequency and voltage.

FIGURE 1

Share of regional installed capacity of SHP by country

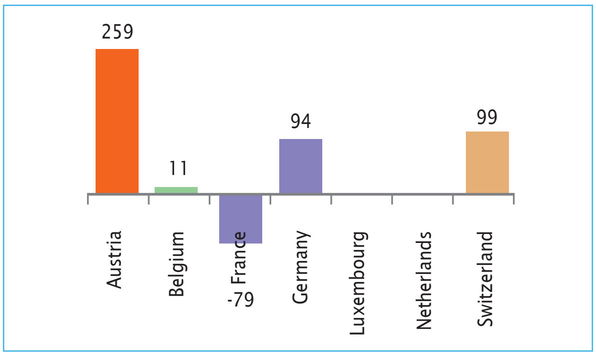


Source: *WSHPDR 2016*[21]

The electrical energy portfolio is different from country to country dependent on their strategy, as well as geographic and climate characteristics. Renewable energy sources in the north are ruled by onshore and offshore winds. Geothermal, biomass and solar power are being developed in all regions, especially in Germany with strong renewable policies. In the Alpine region, large and SHP have a dominant role in electrical energy production and contribute, as in Austria,[1] up to 60 per cent of the country's electrical energy production. The hydropower potential, especially of large hydropower, is nearly fully developed, and development is mostly still possible in the SHP sector. Although some countries increased the share of SHP, others saw a decrease (in some cases due to newer, more accurate data), while the overall share of SHP in the region remained around the same.

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for Western Europe



Sources: *WSHPDR 2013*,[20] *WSHPDR 2016*[21]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.

TABLE 1

Overview of countries in Western Europe (+ % change from 2013)

Country	Total Population (million)	Rural population (%)	National electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Austria	8.69 (+6%)	32	100	21,954 (+3%)	68,015 (-4%)	12,452 (-2%)	39,851 (-7%)
Belgium	11.25 (+8%)	3	100	15,802 (+0%)	91, 000 (0%)	107 (0%)	300 (0%)
France	66.63 (+1%)	15	100	128,943 (+4%)	550,300 (0%)	25,419 (+19%)	68,000 (0%)
Germany	81.45 (0%)	26	100	199,200 (+16%)	647,000 (+6%)	4,350 (0%)	19,147 (0%)
Luxembourg	0.57 (+12%)	15	100	1,800 (9%)	2,859 (-37%)	40 (+1%)	102 (0%)
Netherlands	16.88 (0%)	17	100	31,250 (+17%)	116,800 (-1%)	37 (-2%)	109 (0%)
Switzerland	8.3(+4%)	26	100	17,855 (0%)	69,633 (9%)	12,297 (0%)	39,308 (+5%)
Total	**193.77 (+1%)**	—	**100**	**416,804 (+10%)**	**1,543,262 (+2%)**	**54,702 (+8%)**	**166,817 (-1%)**

Sources: Various[1,2,3,4,5,6,7,20,21]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

In order for the European countries to achieve their renewable energy targets by 2020, including the integration of a large amount of wind and solar power to the European electricity transmission system, new infrastructure is crucial. New high voltage trans-boundary lines and enough electrical energy storage capacity are critical for net security and stability.

TABLE 2

Classification of small hydropower in Western Europe

Country	Small (MW)	Mini (MW)	Micro (kW)	Pico (kW)
Austria	2-10	0.5-2.0	50-500	Up to 50
Belgium	< 10	—	—	—
France	2-10	0.5-2.0	Up to 500	—
Germany	< 5 or < 1	—	—	—
Luxembourg	1-10	up to 1	—	—
Netherlands	< 10	—	—	—
Switzerland	1-10	0.1-1.0	—	—

Sources: Various[8,9,10,15,21]

The pump-storage hydropower plants are still the most reliable electricity storage method of providing necessary power and capacity. Several pump-storage projects in the area are under construction with more pump-storage plants in the preparation phase, but development has been slowed down by low energy price levels in Europe in recent years.

Small hydropower definition

While all the countries (except Switzerland) are part of the European Union, the SHP definition is not universal and various SHP definitions are applied (Table 2). All countries (except Switzerland) have published data on plans to increase SHP, in some cases significant increases can be expected.

Regional SHP overview and renewable energy policy

Austria, Belgium, France, Germany, Luxembourg, the Netherlands, and Switzerland are the seven countries that use SHP. SHP support mechanisms exist in all countries through tradable green certificates (Belgium), investment support or subsidies (the Netherlands, and for Austria from 2010 onwards), and feed-in tariffs (Austria, France, Germany, Luxembourg, Switzerland). The Water Framework Directive is being implemented in all European Union member states (only Switzerland is not part of the European Union).

The total installed SHP capacity (defined as up to 10 MW) is around 6,000 MW in Western Europe. France has the highest installed SHP capacity, followed by Germany, Austria and Switzerland. Table 3 shows the installed SHP capacities, most of the information on SHP potential was not available so planned capacity additions were reported instead. The Stream Map project reveals that during the last 10 years new SHP potential in Western Europe has been greatly affected by environmental legislation, especially for sites in designated areas, such as Natura 2000, and sites affected by the Water Framework Directive, among others.[18]

Mitigation measures will add to the costs of electricity generation. Germany, the fourth largest country with regard to SHP installed capacity within the EU, experienced the largest reduction of its hydropower resource; only 7 per cent of the economically feasible potential can be realized under current conditions. Slightly larger environmentally compliant potential has been identified in France (some 50 per cent). In Austria, the Stream Map project, for example, recommends higher economic support to cover the additional environmental costs.[18]

Barriers to small hydropower development

All countries have to increase their renewable energy share by 2020. The endeavoured share of the renewable

TABLE 3

Small hydropower in Western Europe (+ % change from 2013)

Country	SHP potential (MW)	Planned SHP (MW)	Installed capacity (MW)	Annual generation (GWh)
Austria	1,780 (+36%)	412	1,368 (+23.3%)	6,158 (+23.5%)
Belgium	103 (+11.9%)	31	72 (+18%)	352 (+84%)
France	2,615 (0%)	594	2,021 (-4.2%)	5,436 (-21.4%)
Germany	1,830 (0%)	N/A	1,826 (+5%)	8,043 (0%)
Luxembourg	44 (0%)	10	34 (0%)	100 (0%)
Netherlands	12 (+300%)	9	3 (0%)	8 (0%)
Switzerland	At least 859 (+13%)	N/A	859 (13%)	3,770 (10.8%)
Total	**7,243 (+9%)**	**>1,056**	**6,180 (+6%)**	**23,867 (+0.9%)**

Sources: Various[11,12,13,14,15,16,17,21]

Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

sources in the country energy mix is different for each of the countries, ranging from 34 per cent in Austria to just 14 per cents in the Netherlands. The difference is triggered by the regional availability of the renewable energy sources.

The main natural limitation for hydropower is locally available hydrological potential of the region, especially available hydraulic head. In the countries with a low head potential such as the Benelux countries or North Germany, additional promising hydro-potential is in the installation of the plants on existing navigation and flood control weirs.

However, with higher environmental expectations regarding hydromorphology due to the implementation of the European Water Framework Directives,[19] strict environmental conditions (ecological minimum flow, fish up- and downstream migration possibility, fish friendly turbines, free sediment transport along rivers, and influence of flow variation by hydropeaking) are restricting the energy production and jeopardizing technical and economic viability of new and also existing projects. Licensing procedures of the of the completely new hydropower sites must include comprehensive assessments of environmental (including limnological) concerns with respect to European, national and federal but also the welfare of stakeholders such as fisheries, tourist or recreation groups. Modification of the regulations and clarification of the environmental rules is expected in 2017 on the European level.

4.4.1 Austria

Martina Prechtl-Grundnig and Thomas Buchsbaum, Kleinwasserkraft Österreich

Key facts

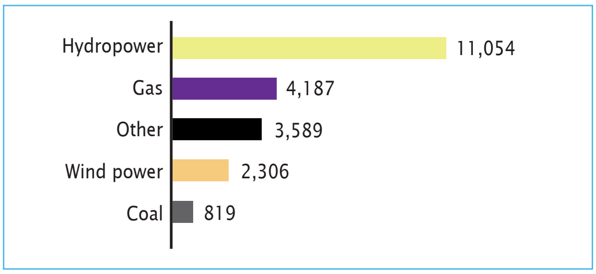
Population	8,699,730[1]
Area	83,878.99 km^2
Climate	A temperate, continental climate. Cloudy, cold winters between December and January with frequent rain and some snow in the lowlands and snow in the mountains with temperatures averaging between -7°C and -1°C. Summers, between June and August, are moderate with occasional showers and temperatures averaging between 18°C to 24°C in July. There are three climatic regions: - East: Pannonian climate with a continental influence; low precipitation, hot summers, but only moderately cold winters; - Alpine Region: Alpine climate with high precipitation (except inner Alpine valley regions such as the upper Inntal), short summers, long winters; - Remainder of the country: transient climate influenced by the Atlantic (in the West) and a continental influence in the South East.[2]
Topography	Mountainous in the south and west (the Alps), along the eastern and northern borders the country is mostly flat or gently sloping. The Alpine regions comprise 67.1 per cent (56,244 km^2) of Austria's total land area. The highest point is Grossglockner at 3,798 metres.[2]
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.[2]
General dissipation of rivers and other water sources	Austria is situated in 3 transboundary river basin districts: Danube, Rhine, and Elbe. Overall, there are 7,339 river water bodies and 62 lakes. Approximately 96 per cent of Austria's territory is part of the Danube River basin, which has an average flow of 1.955 m^3/sec at the border to Slovakia. Approximately 3 per cent of the territory is part of the Rhine basin and 1.1 per cent the Elbe River basin.[2]

Electricity sector overview

Total installed capacity in Austria, as of 1 January 2016, was 21,954.89 MW. Slightly more than half (50.3 per cent) was from hydropower installations, including pumped storage facilities. Approximately 19 per cent came from gas powered plants, 10.5 per cent from wind energy, 4 per cent from coal, and the remainder from other sources including oil, solar, biomass and geothermal resources (figure 1).[3]

FIGURE 1

Installed capacity by source in Austria (MW)



Source: Austrian Power Grid[3]

In 2013, the total electricity generation in Austria was 68,015 GWh, with hydropower (including small hydropower) contributing more than 39,851 GWh, or approximately 57 per cent.[19] The total share of renewable energy in the electricity sector was 67 per cent.[4] The exchange balance was 7,271 GWh with the majority of the imported electricity coming from Germany (50 per cent) and Czechia (42 per cent).[4]

The electrification rate is 100 per cent and, aside from some remote mountain lodges, there is 100 per cent connection to the national grid. Following the Austrian Electricity Industry Organisation Act (EIWOG) in 2000, the Austrian Electricity market has become 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 from hydropower plants. The company also has purchase rights to 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 Republic of Austria as the majority shareholder with 51 per cent of the shares. 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 over-the-counter 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, which 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.

Austrian electricity consumers pay a price based upon three components: the amount charged by the supplier which is set by individual suppliers; a network charge to the system operator which is set by E-control and based upon the grid connection of individual consumers; and taxes and surcharges levied by the State, including VAT. In 2013, the average gross cost, including energy taxes and VAT, was EUR 0.205 (US$0.273) for households and EUR 0.106 (US$0.141) per kWh for industrial users.[5]

Small hydropower sector overview and potential

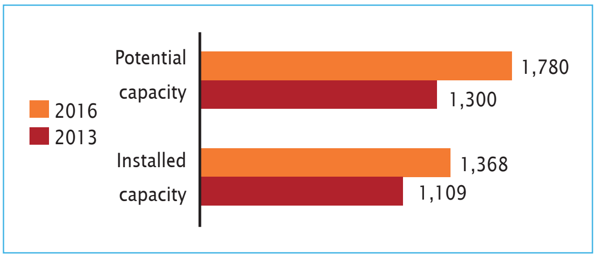
Regulated by ÖNORM, small hydropower (SHP) is defined as plants with a maximum capacity of 10 MW.[6] Austria has an estimated total installed SHP capacity of 1,368.4 MW. However, there is no reliable data on the potential installed capacity in the country. Nonetheless, in the 2013 World Small Hydropower Power Development Report, potential capacity was based upon a government target of achieving 1,300 MW installed capacity from 2,870 SHP plants by 2020.

With the current installed capacity of 1,368.4 MW (an increase of 23 per cent compared to data from 2013) with a valued production (based on average 4,500 full load hours) of 6,157.8 GWh from 2,986 plants, this target has already been achieved.[7] A new target of 1,780 MW capacity has been set implying that there is, at least, this potential in the country, 76.9 per cent of which has so far been achieved (Figure 2). The Stream Map project has also detailed the potential within the country as 3,350 MW of theoretical potential, 2,450 MW of technically feasible potential and 2,100 MW of economically feasible potential. However, regarding economic potential with environmental constraints as of 2009, the amount was estimated at 1,650 MW.[18]

The 2,986 SHP plants identified above are certified as Green Power Plants by the Austrian authorities. However, not all SHP plants are identified as such. Thus the actual number of SHP plants, and therefore the total installed and generating capacity, has the potential to be significantly higher. Currently SHP accounts for approximately 11 per cent of the total installed hydropower capacity and approximately 15 per cent of the total annual generation.

FIGURE 2

Small hydropower installed and potential capacities in Austria 2013-2016 (MW)

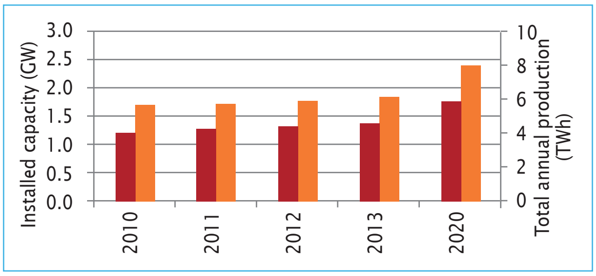


Sources: Energie-Control Austria,[7] *WSHPDR 2013*[8]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

According to the Austrian Energy Strategy 2020, the new target for SHP is to achieve a generation of 8,000 GWh, from an installed capacity of approximately 1,780 MW by 2020 (Figure 3).[9] Recent studies from three out of the nine federal states in Austria show there is still potential for SHP development. Considering all European directives and Austrian laws, especially those for nature conservancy and water protection, undeveloped SHP potential annual generation is estimated as at least 600 GWh/a in Tirol, 500 GWh/a in Styria, and 100 GWh/a in the large rivers of Upper Austria.[10,11,12]

FIGURE 3

Small hydropower capacity and annual production in Austria 2010-2020



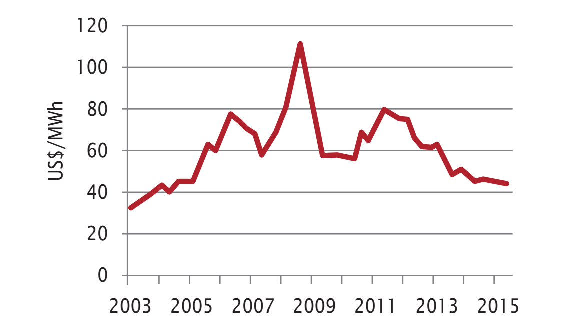
Sources: Erneuerbare Energie Österreich,[9] ESHA[18]

Approximately 85 per cent of the total electricity produced in 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 energy is traded at the EEX platform in Leipzig, Germany. In both instances, the obtained price is strongly linked to the Phelix Base Quarter Future derivatives, which is traded at EEX. A market based purchase price determined on the Phelix Base Quarter Future is also settled in the Austrian Green Electricity Act (ÖSG), which was last amended in 2012. This price is determined quarterly by Energie-Control Austria as shown in Figure 4.[13]

Before 2003 the federal states of Austria had individual tariff regulations. Starting in 2003, a new tariff system was installed country-wide. The tariff was dependent on the amount of electricity delivered into the public grid. For new SHP plants (or those undergoing refurbishment that increases the mean annual production or capacity more than 50 per cent) the tariffs are shown in Table 1.

FIGURE 4

Market price for small hydropower in Austria (2003-2015)



Source: Energie-Control Austria [13]

TABLE 1

Small hydropower feed-in tariffs for new plants in Austria 2003

Electricity delivered to the grid	Tariff (EUR (US$) per MWh)
Up to 1 GWh:	62.5 (83.25)
The next 4 GWh:	50.1 (66.73)
The next 10 GWh:	41.7 (55.54)
The next 10 GWh:	39.4 (52.48)
And if more than 25 GWh:	37.8 (50.35)

Source: Energie-Control Austria[13]

If the operator of the plant was able to refurbish the plant to increase the mean annual production or the capacity by more than 15 per cent, tariffs demonstrated in Table 2 were applied.

TABLE 2

Small hydropower feed-in tariffs for refurbished plants (> 15%) in Austria 2003

Electricity delivered to the grid	Tariff (EUR (US$) per MWh)
Up to 1 GWh:	59.6 (79.39)
The next 4 GWh:	45.8 (61.01)
The next 10 GWh:	38.1 (50.75)
The next 10 GWh:	34.4 (45.82)
And if more than 25 GWh:	33.1 (44.09)

Source: Energie-Control Austria[13]

Starting from 2010, an investment support system has been installed replacing the FIT system (Table 3). However, the new system is only valid for new plants constructed and set into operation after 2010. Existing plants running under the FIT system will continue to receive the tariffs.

Since the Green Electricity Act was last amended in 2012, new SHP plants (or those undergoing refurbishment that increases the mean annual production or capacity more than 15 per cent) with a capacity below 2 MW can choose between investment support or the feed-in tariffs as shown in Table 4. SHP plants above 2 MW have to take an investment support equal to that of the 2010 installed system.

TABLE 3

Small hydropower investment support system in Austria 2010

Installed capacity	Support description
Less than 50 kW	1,500 EUR/kW (US$2,000/kW)
500-2,000 kW	20-30 per cent of investment up to a max. EUR 1,000-EUR 1,500/kW (US$1,300-US$2,000/kW)
50-500 kW	30 per cent of investment up to a max. EUR 1,500/kW (US$2,000/kW)
2-10 MW	10-20 per cent of investment up to a max. EUR 400-EUR 1,000/kW (US$500-US$1,300/kW)

Source: Energie-Control Austria[13]

TABLE 4

Small hydropower investment support system in Austria 2010

Delivered electricity (MWh)	Feed-in tariffs (EUR (US$) per kWh)	
	Refurbishment > 15%	New SHP or refurbishment > 50%
0-500	0.0810 (0.1079)	0.1034 (0.1377)
500-1,000	0.0591 (0.0787)	0.0743 (0.0990)
1,000-2,500	0.0512 (0.0682)	0.0649 (0.0864)
2,500-5,000	0.0373 (0.0497)	0.0542 (0.0722)
5,000-7,500	0.0345 (0.0460)	0.0512 (0.0682)
7,500-10,000	0.0317 (0.0422)	0.0487 (0.0649)

Source: Energie-Control Austria[13]

Renewable energy policy

The Austrian Energy Strategy 2020 aims to increase the share of renewable energy to 34 per cent, reduce greenhouse gas emissions in sectors not subject to emissions trading by at least 16 per cent, and to achieve a 20 per cent growth in energy efficiency by 2020.[14] However, this is seen as an interim target between the longer term target of 100 per cent self-sufficiency by 2050.[15] Studies by the Austrian Environment Ministry show this target to be technically feasible. They note, however, "that the room for manoeuvre for a 100-per-cent supply from renewable energy sources by 2050 is rather small", predicting that in order to achieve this target more than half of the country's energy demand will be met by biomass and hydropower.[16]

The Austrian Eco-Electricity Act 2012 entered into law on 1 July 2012 and includes the following innovations:

- A one-off payment of approximately EUR 110 million (US$119.5 million) to reduce the waiting list for projects dealing with wind, photovoltaics, and small-scale hydro power stations;

- Raising of the former annual subsidization budget of EUR 21 million (US$22.8 million) to EUR 50 million (US$54.3 million). Within 10 years this budget will be reduced by annually EUR 1 million (US$1.1 million), to an amount of EUR 40 million (US$43.5 million);
- New, binding, eco-electricity targets for the year 2020 based on gains in capacity (MW) and production (TWh) for eco-electricity generated from waterpower, wind energy, biomass/biogas, and photovoltaics;
- There will again be separate subsidization budgets for the individual technologies;
- The raw material surcharge for biogas plants was further developed and became a surcharge on operating costs;
- Useful incentives and measures to further enhance the efficiency of the subsidization scheme and the eco-electricity projects submitted;
- Restructuring of the funding tools: Greater transparency in connection with considerable concessions for low-income households and energy-intensive enterprises.[17]

Barriers to small hydropower development

A very low market price for electricity, which has been below EUR 40/MWh (US$53/MWh) since the beginning of 2013, is creating pressure on the whole SHP sector, in particular for plants with a capacity higher than 2 MW and for operators who are forced to invest in fish bypass systems or build/refurbished a SHP plant with investment support. Requests from the Government regarding environmental concerns, such as fish bypassing and reserved flow, are increasing continuously, and sometimes the consensus reached is not stable and reliable. In general, public opinion towards SHP is good. However, some opposition to local development from local populations may cause delays in project realization.

4.4.2 Belgium

Johanna D'Hernoncourt, Association for the Promotion of Renewable Energies (APERe); Sonya Chaoui, SPW-DGO4, Department for Energy and Sustainable Housing

Key facts

Population	11,258,434[1]
Area	30,527.92 km[2]
Climate	Maritime temperate, mild in the summer and in the winter, with differences between the coastal zone and the mainland. The average temperatures in January range between 0.7°C and 5.7°C, and in July between 14°C and 23°C.[3]
Topography	Coastal plain in the North west, central plateau (about 100 metres above sea level) and Ardennes uplands in the South-East (South of the Rivers Sambre and Meuse furrow) with highest peak: Signal de Botrange at 694 metres.[2]
Rain pattern	Precipitation in the form of rain is significant: between 700 mm and 850 mm annually, for 200 days on average, with a variability of about 25 days (230 days in the High Fens and 182 at the coast).[3]
General dissipation of rivers and other water sources	Suspected to increase in the years to come due to climate change. Combined to smaller debits in the rivers in the summer, suspected to induce water shortages.[4]

Electricity sector overview

Belgium is a federal state of three regions: the Flemish region, the Walloon region and the Brussels-Capital region. The evolution of the Belgian energy policy has been shaped by this system, and has led to the transfer of wide competences from the federal state to the regions.

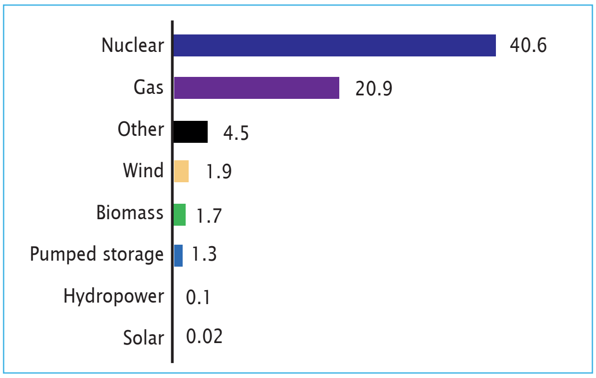
Energy consumption in 2013 was 405 TWh, of which fossil fuels accounted for 82 per cent and nuclear for 10 per cent. Since 2005, the renewable sources share in energy consumption have increased from 2.3 per cent to 7.7 per cent (31 TWh).[5] The objective is to reach 13 per cent according to the European Directive on the promotion of the use of energy from renewable sources.[6] The installed capacity for electricity production from renewable sources was 5.1 GW for a total capacity estimated to be 20.6 GW by the Transport System Operator Elia, of which 53 per cent for solar photovoltaic, 34 per cent for wind energy, 11 per cent for biomass, and 2 per cent for hydropower.[15] In 2013, the production of electricity from renewable sources reached 3.7 TWh in Wallonia, 6.3 TWh in Flanders and 105 GWh in the Brussels Region.[7]

According to the World Bank, 100 per cent of the Belgian population has access to electricity.[8] The Belgian grid is well developed, and the main challenge currently is its management of integrating variable and decentralized energy production.[9]

Phasing out nuclear production is politically favourable but the timing is still under discussion at the federal level. With technical problems in three reactors out of seven during the 2014 winter, the country has been depending on imports, and needed to constitute strategic reserves to ensure electricity supply in case of a cold winter (in this case the demand is high in all of Western Europe). An energy pact to provide a view at the 2050 horizon (including development of renewable energy) is under discussion between the federal government and the regions.

FIGURE 1

Electricity generation by source in Belgium (TWh)



Source: Belgian Observatory of Renewable Energies[7]

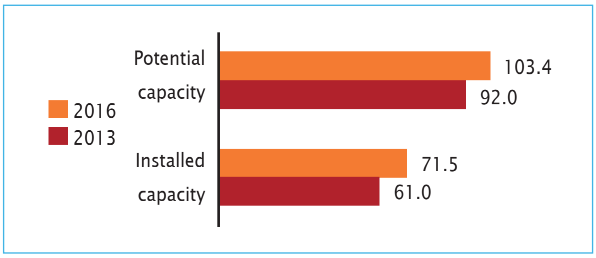
In 1999, Belgium implemented the European Directive concerning the internal markets in electricity, which organized the unbundling of the roles in the electricity market (production, transport, distribution, supply, regulation, etc.) and included progressive privatization.[10] The CREG (Commission de Régulation de l'Electricité et du Gaz) on the federal level and three regional entities act as regulators on the electricity and gas markets, and they control the distribution tariffs. In May 2015, the electricity for private use costs EUR 0.199/kWh (US$0.22/kWh) with small differences between regions due to price differences for the distribution system operators.[11]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Belgium is up to 10 MW. Installed capacity of SHP is approximately 71.5 MW while the potential is estimated to be 103.4 MW indicating that 69 per cent has been developed. Between the 2013 and 2016 World Small Hydropower Reports installed capacity has increased by approximately 17 per cent while estimated potential has increased by approximately 12 per cent (Figure 2).

FIGURE 2

Small hydropower capacities 2013-2016 in Belgium (MW)



Sources: ICEDD,[13] *WSHPDR 2013* [14]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

With only two sites equipped with plants over 10 MW capacity (40.744 MW installed or 36 per cent of total installed capacity), most sites equipped in Belgium are considered SHP.[12] Installed capacity in Belgium in 2014 was 112.216 MW on 115 sites,[13] for a net normalized production of 351.8 GWh.[6] In 2013, the production accounted for 0.46 per cent of the final electricity consumption. Most of the sites (85 per cent in terms of number, 99 per cent in terms of capacity) are installed in the southern part of Belgium, in the Walloon Region. About three quarters of installed capacity (on 14 sites) are on navigable waterways.[7] The main remaining potential is situated on navigable waterways in the Walloon Region. The regional government and its management entity SOFICO have adopted the decision to concede for private operation (20 years) 21 public sites on the Rivers Meuse, Sambre and Ourthe,[16] for a total of 71 GWh of increased annual production by 2020. These sites have smaller heads (2 to 3 metres) than sites that that have been exploited historically on navigable waterways. For a long time, it constituted a challenge to find an economically viable technical solution.

Belgium also has a strong history of hydropower exploitation on non-navigable waterways before and during the industrialization period. More than 2,500 sites of old mills or factories driven by water have been identified.[17] A part of these historical heads could be equipped, for an estimated increased annual production of 2.6 GWh by 2020 and an additional 1.8 GWh by 2030.[18] Most of these sites are in the private domain, with private investment for refurbishment. The development of citizen co-operatives for the investment in the refurbishment of small sites is progressing. Revamping of historical sites currently in operation is expected to bring a capacity gain of 5 per cent which corresponds to 18 GWh of increased annual production.[19] Depending on the age of the installations, the revamping will be undertaken progressively in the coming 10 to 15 years. By the 2030 production of 460 GWh could be reached.

The Walloon government and the electricity and gas regulator CWaPE (Commission Wallonne pour l'Energie) have recently revised the supporting mechanism for new hydropower projects through green certificates. The aim is to reach an Internal Rate of Return for the projects of 7 per cent after tax.[20] Moreover, since 2014, the public investment aid in Wallonia (up to 20 per cent of the total cost) also allows for the eligibility of environmental investments (fish licenses for a cost of a maximum 35 per cent of the total investment).[21] Since environmental investments such as fish licenses constitute an economic barrier to large scale projects, this change in regulation brings new opportunities for SHP developments. Although the country's hydropower potential is already well exploited, the economic incentives put in place and the equipment program of the navigable waterways are expected to bring the sector even closer to its technical potential.

Renewable energy policy

Belgium uses a tradable green certificate (TGC) system as its primary support mechanism for the deployment of renewable power technologies. There are four different TGCs (i.e. Federal, Flemish, Wallonian and Brussels green certificates) that vary in price and conditions. The Federal Government is currently working on an energy pact, to provide the country with a vision of its energy sector at the 2050 horizon. Each region is in charge of defining the roadmaps to reach regional targets for renewable energy production, in the framework of the national target of 13 per cent of the final gross energy consumption. During 2015, the Walloon government already drafted a roadmap for renewable energy development towards 2030.[22] The roadmap still needs to pass a few legislative steps to be fully adopted and binding. It specifies the targets of respectively 380 and 420 GWh of annual hydropower production by 2020 and 2030. Belgium is progressing towards its objective of 13 per cent of renewable energy in energy consumption. A clear road map agreed by all regions is awaited to plan for the future years and beyond 2020.

Barriers to small hydropower development

Hydropower has historically been largely exploited in Belgium. In the Walloon Region, the equipment plan for navigable waterways and the revision of financial support for SHP development are expected to bring the sector even closer to its technical potential. However, with higher environmental expectations regarding hydromorphology due to the implementation of the European Water Framework Directive,[23] strict environmental conditions (ecological minimum flow, free fish migration up- and downstream, fish friendly turbines, etc.) are imposed on investors and sometimes jeopardize the technical or economic viability of the projects. A change in regulation to help clarify the environmental rules is expected in 2017.[24]

4.4.3 France

European Small Hydropower Association, Stream Map; Jean Marc Levi, France Hydro Electricité

Key facts

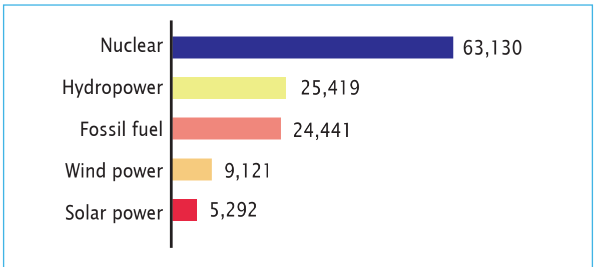
Population	63,697,865[1]
Area	549,000 km[2]
Climate	Three types of climate may be found; oceanic (west), continental (central, east) and Mediterranean (south), (except in the mountainous south-west). Average temperatures in northern Brittany are 6°C in winter and 16°C in summer. Paris averages a yearly temperature of 11°C. The southern coastal city of Nice experiences an annual average of 15°C.[2]
Topography	Mostly flat plains or gently rolling hills in north and west; the remainder is mountainous, especially the Pyrenees in the south and the Alps in the east. The country's highest point is Mont Blanc at 4,807 meters.[2]
Rain pattern	Annual precipitation ranges from 680 mm in the central and southern region to 1,000 mm around Paris / Bordeaux. In the northern coastal and mountainous areas precipitation can reach more than 1,120 mm.[2]
General dissipation of rivers and other water sources	Five major rivers create the drainage system of France. The Seine (780 km) flows through the Paris Basin and has three tributaries, the Yonne, Marne and Oise Rivers; it finally drains into the English Channel. The Loire (1,020 km) is the longest river in France and flows through the central region. The Garonne is the shortest of France's major rivers. It rises in the Pyrenees, across the border with Spain, and empties into the Bay of Biscay at Bordeaux. The Rhône is the largest and most complex of French rivers. Rising in Switzerland, it flows southward through France for 521 kilometres, emptying into the Mediterranean. Lastly, the Rhine flows along the eastern border for about 190 kilometres (118 miles), fed by Alpine streams.[2]

Electricity sector overview

The total installed capacity in France at the end of 2014 was 128,943 MW (Figure 1).[5] Approximately 49 per cent of the total installed capacity came from nuclear energy. Hydropower capacity was 19.7 per cent of the total installed capacity, while fossil fuel-fired thermal capacity represented 18.7 per cent. The total wind power capacity was 7 per cent, and the total solar energy capacity was 4 per cent. This offset 1,240 MW of closures at coal-fired plants, and 65 MW at oil-fired plants.[5] Net electricity generation for 2015 was 37,921 GWh.

FIGURE 1

Installed capacity by sources in France in 2014 (MW)



Source: Ministry of Energy[5]

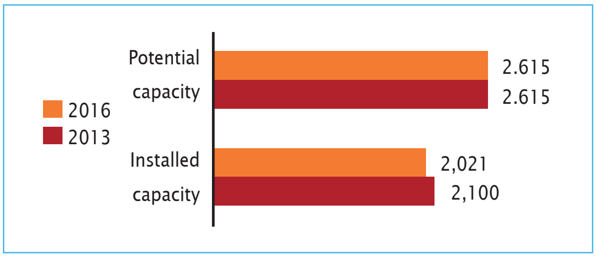
The Ministry of Ecology, Sustainable Development and Energy is in charge of regulating energy matters. The electricity grid is owned and operated by Réseau de Transport and Electricity. The French electricity market is open. However, it remains largely dominated by the formerly state-owned EDF. EDF had an installed capacity of 98,237 MW at the end of 2014 (76 per cent of the total installed capacity of France). The electrification rate of the country is 100 per cent.[6]

Small hydropower sector overview and potential

In France, small hydropower (SHP) is defined as plants having an installed capacity up to 10 MW. The SHP installed capacity is 2,021 MW, and potential is approximately 2,615.[7]

FIGURE 2

Small hydropower capacities 2013-2016 in France (MW)



Sources: Eurobserver,[7] *WSHPDR 2013*[9]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

For small hydro, the total potential is estimated at 527 new Greenfield sites (1,214 MW and 4,368 GWh), and at equipping 734 of existing small weirs (303 MW and 1,068 GWh). To estimate the feasible potential, the following ratio was applied: cut one third for economic and technical constraints and another third for environmental constraints (revision of classification in course), i.e. 419 power plants, 525 MW and 1,812 GWh by 2020.

A commitment agreement for the development of sustainable hydropower in compliance with aquatic environments restoration requirements was signed in June 2010 to promote hydropower, if deemed suitable considering the environmental specifications. A part of the agreement directly concerns the equipment of existing weirs. The methodology and the "suitable conditions" to build a power plant onto existing weirs need to be made more precise. A guidebook *Towards the Hydroelectric Plant of the 21st Century* for the development of SHP plants with regard to the natural environment is available.[10] It defines standards for the conception of a highly environmental quality plant. This guide is recognized and disseminated by national administrations.

The French water administration drafted an inventory of obstacles in rivers, and aims to assess the degree to which those 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. A protocol called *Informations sur la continuité* écologique (ICE) has been also created to measure the capacity of obstruction of these obstacles.[6] This vast project, brings together a large number of partners, identifies the installations causing the greatest problems and makes it possible to set priorities for corrective action. It will be also a good tool to identify new potential sites for SHP.

The Government and EDF are working on a guidebook for the environmental compliance of hydropower plants in France.

The total hydropower potential in France is about 200,000 GWh/year. In 2014, there was 25,410 MW of hydropower capacity in operation therefore the SHP capacity constitutes about 9 per cent.[3]

The Government sees renewable energy as playing an increasingly important role in meeting energy needs. According to a study released in November 2013 by the Ministry of Environment, France has the potential to increase its hydropower.[7]

Renewable energy policy

A regional plan for climate, air and energy *(Schéma régional du climat de l'air et de l'énergie, SRCAE)*, was jointly developed by the State and the regional authorities.[11] In particular, this plan defines, for 2020 and by geographical area, qualitative and quantitative regional targets for the valorization of potential territorial renewable energy, taking into account the national targets. In practice, this means identifying all sources for the production of renewable energies and of energy savings according to socio-economic and environmental criteria, and defining, in association with the local stakeholders (infra-regional authorities, companies and citizens), the level of regional contribution in achieving the targets set by France. This plan represents a strategic planning tool to guide the activities of local and regional authorities.[6] SRCAE is in progress.

SRCAE, for hydropower potential, is based on producers' data and compatibility with lists of no-go rivers and restoration of river continuity priorities.

France was the second largest producer of renewable energy in the EU in 2012. The strong points of the country are hydro, biofuels, and geothermal energy used in heating networks. France has the potential to achieve important targets in the renewable energy production. The 2012 share of renewable energy in France amounted to 13.7 per cent; the target for 2012 has been defined as 23 per cent.

In August 2015, the Energy Transition Law was promulgated. This law set the framework for the energy transition towards a greener and cleaner energy.

Legislation on small hydropower

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 around 30 to 40 years if there is a significant investment. France has a lot of perpetual old permits for former mills subject to new environmental restrictions. The Government's priority is a simplification of the legislation; some measures like "Unique Authorization" are removed. The idea is to comprise the different authorizations within one category in order to accelerate the process and relieve the administrative burden.

Residual flow regulation exists, i.e. 10 per cent of inter-annual average flow, and for modules over 80 m^3/s, 5 per cent of the module is admissible.[8] While the minimum (10 or 5 per cent) is set by the law, the adapted minimum ecological flow is set case by case through environmental assessments. The most used method is the micro-habitats method (EVHA), but there are other possible methods adopted when EVHA does not suit the type of river. Since 1984, the reserved flow was around 10 per cent of the average annual flow. Since 2006, 10 per cent is the minimum, and local administrators often ask for more (12 to 17 per cent), without any justification on improvement or maintenance of the ecological status. In periods of extreme low water levels, the Préfet, head of the Department (French subdivision) can decide to lower temporarily the residual flow. A feed-in tariff (FIT) for installed capacity not exceeding 12 MW (art. 10 par. 2 Loi n°2000-108; art. 2 Décret n°2000-1196) has been established. H97 is a 15-year contract that was signed in 1997. This was renewed in October 2012 for another 15 years against a plan of investment.[8] H97 FIT is between EUR 55 and EUR 65/MW (US$72 and US$85/MWh). H07 is a 20-year contract for new SHP plants or for the plants which are renewed (investment of EUR 1,172/kW (US$1,525/kW). The H07 FIT is between EUR 60 and EUR 100/MWh (between US$78 and US$130/MWh). Plants over 400 kW of installed capacity do not qualify for the tariff (threshold effect).

Barriers to small hydropower development

One of the main barriers for SHP is the classification of rivers carried out by the Government in 2012 (affecting 71 per cent of the hydropower potential) The French producers who cannot or do not wish to invest to benefit from a new FIT contract will have to sell their production directly on the market. The market price does not take into account specificities of the SHP production (i.e. the green value and the decentralized decentralized production. The level of market price (around EUR 38/MWh in 2015) does not permit any investment, and may push some small units into bankruptcy. Conflict between river protection and hydro development is rising.

The French Government is carrying out a pre-planning mechanism. The Government classifies the rivers in order to determine absolute-protected rivers for water bodies of high status, migratory species or ‘biodiversity reservoirs’ while areas with renewable potentials are designated at the regional level.

4.4.4 Germany

Stephan Theobald, Universität Kassel

Key facts

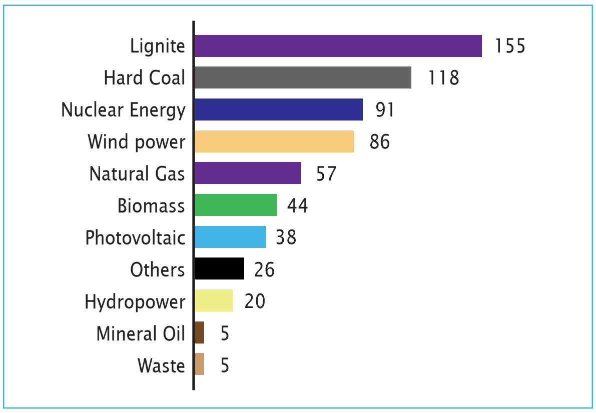
Population	81,459,000[4]
Area	357,340 km[2]
Climate	Warm and humid temperate mid-latitude climate, oceanic influence weakens from the north-west to the south-east, relatively mild winters and summers, occasionally very cold winters and very hot and dry summers. Mean temperature in winter (December – February) is 0.9°C and in summer (June – August) 16.3°C.[9]
Topography	Coasts and lowlands in the north, uplands in the centre, Bavarian Alps in the south with the highest altitude at Zugspitze peak (2,963 metres).[10]
Rain pattern	The average annual precipitation is 789 mm. The amount of rainfall decreases across the country from west to east.[10]
General dissipation of rivers and other water sources	The main flow direction of rivers is from the southern Alpine region and central mean range mountains to the north (Rhine River, Elbe River, Weser River) and to the east (Danube River).[10]

Electricity sector overview

The installed electricity generation capacity in 2015 was 199.2 GW.[1] The gross power production in Germany in 2015 was 647 TWh.[3] Of those, 161 TWh (26 per cent) came from renewable power sources (Bundesverband der Energie- und Wasserwirtschaft BDEW 2015) (Figure 1).

FIGURE 1

Electricity generation by source in Germany (TWh)



Source: Federal Ministry for Economic Affairs and Energy[7]
Note: Data from 2015.

The rate of electrification is 100 per cent. Electricity is mainly produced by private companies with a minor portion of photovoltaic electricity production by private households. The power grid is run by private companies. Prices are partly guaranteed by feed-in tariff (FIT) for renewable energy and with power trading on the electricity stock exchange. Problems in grid stability may rise due to uncontrolled fluctuations of electricity production by some renewable energies like small photovoltaic electricity production facilities, efforts might be undertaken to upgrade necessary installations. Average electricity price in 2014 for households was EUR 0.297, but for industry EUR 0.144.[12]

Small hydropower sector overview and potential

The definition of small hydropower (SHP) in Germany is up to 1 MW. However, definitions of up to 5 MW or even 10 MW can be seen in different documents.[13] As of 2013, Installed capacity of SHP up to 10 MW in Germany was 1,826 MW (up to 5 MW was 1,372 MW and up to 1 MW was 660 MW; Figure 3)[14] while the potential is estimated to be 1,830 MW indicating that nearly all currently identified SHP potential has been developed. Between the 2013 and 2016 *World Small Hydropower Reports* installed capacity has increased by 5 per cent while estimated potential has not changed (Figure 2).

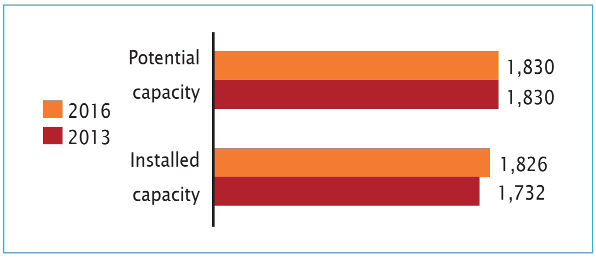
Efforts on SHP are focused on modernization existing SHP. Additional SHP is often hindered by environmental concerns on stream ecology while the benefit of hydropower for climate protection is widely accepted. SHP projects are mainly financed by private companies.

Renewable energy policy

Renewable energy sources including those for electrical energy production are supported by a renewable energy feed-in tariff (FIT) under the legislation of the

FIGURE 2

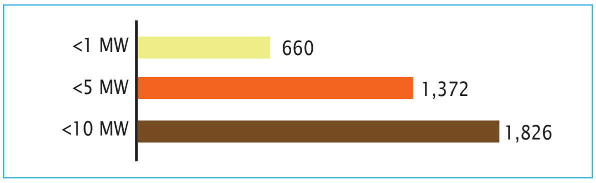
Small hydropower capacities 2013-2016 in Germany (MW)



Sources: Bundesnetzagentur für Elektrizität,[1] Federal Ministry for the Environment,[14] *WSHPDR 2013*[11]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. 10 MW definition is used. Does not include pumped storage.

FIGURE 3

Small hydropower installed capacity in Germany by definition (MW)



Source: Federal Ministry for the Environment[14]
Note: Excludes pumped storage.

Renewable Energies Act (EEG). The entitlement and amount of subsidies are set in the EEG, which also introduced market premiums and flexibility premiums for direct selling by renewable plant operators. The EEG aims for the objective to raise the portion of renewable energy sources on gross electricity production by the year 2025 to more than 40 per cent and by 2050 up to at least 80 per cent (in 2015 it was approximately 26 per cent). Renewable energy sources are expected to represent 18 per cent of the gross energy consumption in 2020.

Usually there are no fees for water use in hydropower. Concession fees are different in every federal state and depend on the project's size, e.g. EUR 10,000 (approximately US$12,000) for 150 kW concession in the State of Hesse. The duration of new concessions is a minimum of 20 years up to a maximum of 30 to 60 years. Mandatory investigations on the environmental impact of a project are a main element of the cost when acquiring a concession; the costs associated with the investigations vary depending on the project and approximating the price in advance can be difficult.

The duration of a FIT is 20 years, while the tariffs are revised every four years. The FIT is set to:

- 12.52 EUR cents/kWh ≤ 500 kW;
- 8.25 EUR cents/kWh ≤ 2 MW;
- 6.31 EUR cents/kWh ≤ 5 MW;
- 5.54 EUR cents/kWh ≤ 10 MW;
- 5.34 EUR cents/kWh ≤ 20 MW.

The EEG also includes additional regulations on annual decreases and on the fulfilment of environmental protection standards.

Besides the Renewable Energies Act, the European Water Framework Directive is influential on the development of SHP.[6] A main objectives of the directive is "to establish a framework for the protection of inland surface waters" on water basin levels. This results in very relevant restrictions for the design and operation of new as well as for existing hydropower.

Residual or minimum environmental flows are regulated by the German federal system and are determined as a fraction or multiple of the mean annual or seasonal low flow. Measures to ensure continuity of the rivers are mandatory for a wide number of hydropower stations and may include fish passage facilities and fish protection installations.

Barriers to small hydropower development

- Difficult to obtain licenses. Licensing of hydropower is very much influenced by the assessment of the possible impact on stream ecology. This applies for the optimization or reactivation of already existing hydropower stations.
- Few entirely new projects constructed on suitable sites are realized. Hydropower on a completely new site is licensed only by an approval procedure including comprehensive assessments of environmental and especially limnological concerns with respect to European, national and federal legislation.
- Expensive assessment for new potential sites. Avoiding undesired impact on stream ecological systems requires an elaborate and usually costly application of hydraulic structures and operation modes.
- In particular for investment in SHP, this complex licensing procedure may be a serious obstacle for further development of hydropower.

4.4.5 Luxembourg

Tom Rennell, International Center on Small Hydro Power

Key facts

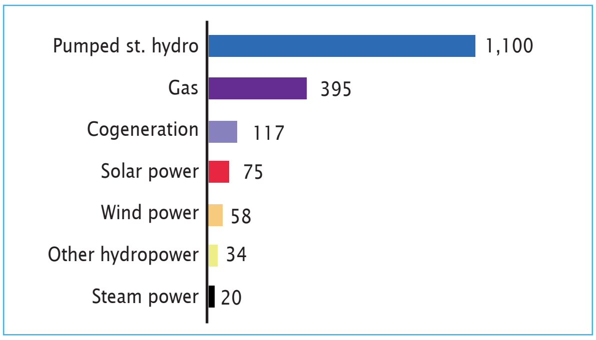
Population	576,000[1]
Area	2,586 km[2]
Climate	Temperate and mild climate. Summers, between June and August, are generally cool, with a mean temperature of approximately 17°C. Winters, between December and February, are seldom severe with an average temperature of approximately 0°C.[2]
Topography	Luxembourg is a landlocked country divided into two distinct geographic regions: the rugged uplands of the Ardennes in the north with an average elevation of 450 metres and home to the country's highest point, Buurgplaatz, at 559 metres; and the fertile southern lowlands, Bon Pays, with an average altitude of 250 metres.[2]
Rain pattern	Annual average rainfall is approximately 750 mm and is generally higher in the south-east. Rainfall is distributed relatively equally throughout the year though on average May, June, November and December are the wettest while April is the driest.[3]
General dissipation of rivers and other water sources	Most rivers drain eastward into the Sauer, the county's longest river at 173 km. The Sauer in turn flows into the Moselle on the eastern border the basin of which includes most of the country's land area. Other important rivers include the Alzette and the Wiltz.[2]

Electricity sector overview

As of 2013 total installed capacity in Luxembourg was 1.8 GW, a large share of which was from the Vianden pumped-storage plant constituting approximately 61 per cent. Gas power plants constituted 22 per cent while the remaining 17 per cent was made up from cogeneration plants, solar power, wind power, non-pumped storage hydropower plants and other sources (Figure 1).[4]

FIGURE 1

Installed capacity in Luxembourg by source (MW)



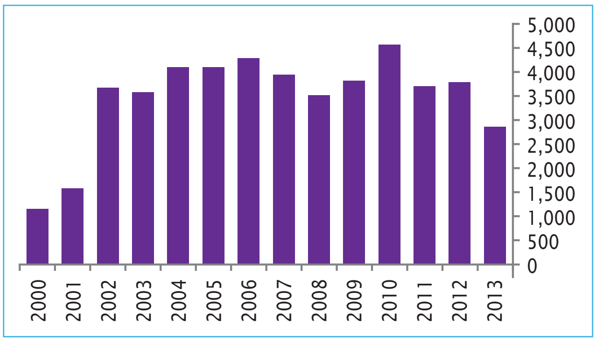
Source: Shemshenya [4]

In 2013, total electricity generation was 2,859 GWh, decreasing approximately 24 per cent from 2012 (Figure 2).[14] In 2014 consumption was 6.45 TWh, vastly outstripping the country's domestic generation resulting in a heavy reliance on imported electricity which amounted to 6.684 TWh in the same year. With exports amounting to 2.623 TWh, imported electricity accounted for approximately 63 per cent of the domestic consumption, one of the highest import rates in the world.[5]

Luxembourg has a 100 per cent electrification rate with the national grid totalling 9,464.1 km of power lines. In 2014, a EUR 130 million investment (US$141 million) was made in improvements to the network.[6] The country also receives imports via two connections to the 220-kV high-tension network in Germany from substations at Quint and Bauler.

FIGURE 2

Electricity generation in Luxembourg (2000-2013) (GWh)



Source: OECD[14]

The electricity market has been fully open since 1 July 2007. Due to the country's low level of domestic generation, competition is driven largely by imports and exports of foreign electricity supply. Thus, Luxembourg's electricity wholesale market is highly interconnected with and dependent on its neighbouring countries.

The main electricity generators in Luxembourg are SEO SA, operator of the Vianden pumped storage power station and Twinerg SA, operator of a 350 MW combined-cycle gas turbine plant. Two industrial cogeneration plants (CEGYCO and CEDUCO) as well as a certain number of domestic cogeneration plants also play a major role.

The electricity grid is jointly managed by: Creos Luxembourg S.A, which is a subsidiary company of Enovos International SA and whose shareholders are the Luxembourgian State, Arcelor Mittal, RWE, Eon and Electrabel; five distribution system operators, Creos Luxembourg SA, Electris (Hoffmann Frères S.à.r.l.), Sudstroum S.à.r.l. & Co S.e.c.s, as well as the local administrations of the cities of Diekirch and Ettelbruck; and one industrial system operator, Sotel SA, which also operates with high wire voltage of 220 and 150 kV and which operates the interconnection with the Belgian transmission grid.

The Institut Luxembourgeois de Régulation (ILR) is the regulatory authority for the electricity sector as well as for gas, telecoms, the postal services and rail. Responsibilities include monitoring competition and setting the calculation method for approved network tariffs and the conditions for access to the network. The ILR is funded by the network operators.

In 2014, average household consumer electricity tariffs were EUR 0.174 (US$0.232) per kWh and EUR 0.099 (US$0.132) per kWh for industry.[7]

Small hydropower sector overview and potential

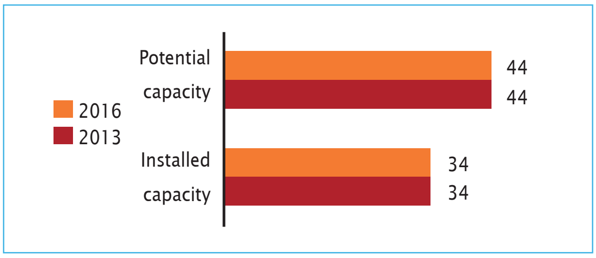
Small hydropower (SHP) is defined as plants with an installed capacity of less than 10 MW. Luxembourg has total installed SHP capacity of 34 MW. Although there is no existing study on the country's potential SHP capacity, a target of 44 MW by 2020 indicates that there is at least an additional 10 MW of capacity that could be developed with existing capacity constituting 77.3 per cent of that target.[8,9] The Stream Map project indicates a gross theoretical potential of 60 MW, while 50 MW are technically feasible and 45 MW economically feasible, which is in line with the 2020 target.[13]

In comparison to the 2013 Small World Hydropower Development Report, these figures remain unchanged (Figure 3).[10]

Luxembourg currently has 33 SHP plants in operation with a target of 42 by 2020. Generation in 2010 was estimated at 100 GWh; the 2020 target is 124 GWh.[8] Given the extremely small size of the country, potential is highly limited. Identified sites consist of one new 5 MW site on the Sauer river, the reactivation of 10 micro power plants and the upgrading of SEO's current hydropower plants.[9]

FIGURE 3

Small hydropower capacities 2013-2016 in Luxembourg (MW)



Sources: IRENA,[8] ESHA,[9] *WSHPDR 2013*[10]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Feed in-tariffs are available for plants up to 6 MW with a guaranteed 15-year annual digression rate of 0.2 per cent since 2008 (Table 1). There are investment subsidies available based upon the difference in eligible expenses between the cost of investment in a gas power station of equivalent power. The percentage of eligible expenses available for subsidy varies with the size of the company, from 65 per cent to 45 per cent.[9]

TABLE 1

Feed-in tariffs for small hydropower in Luxembourg

Plant size	FIT (Euros (US$) per kWh)
Up to 1 MW	0.105 (0.140)
1 MW to 6 MW	0.085 (0.113)

Source: ESHA[9]

Permits required for the construction of SHP plants are as follows:

- Authorization for abstraction, impounding works and any other engineering works from the Water Management Administration;
- Environmental license from the Ministry of Environment;
- Construction license from the Municipality;
- Electricity generation from the Institut Luxembourgeois de Régulation.[9]

Renewable energy policy

The National Renewable Energy Action Plan (NREAP), submitted in August 2010, sets a target of 11 per cent share of renewable energy in final energy consumption by 2020 as well as a 10 per cent share of renewable energy in final energy consumption in the transport sector. Key increases to electricity generation are expected from biomass contributing 300 GWh, onshore wind power 200 GWh and solar photovoltaic 84 GWh.[12]

In Luxembourg, electricity from renewable sources is mainly promoted through a feed-in tariff as well as through subsidies. Private individuals operating small solar installations, for instance, are entitled to tax benefits. Access of electricity generated from renewable energy sources to the grid is subject to the general provisions of energy laws and renewable energy is not given priority. However, electricity generated from renewable energy sources is granted various privileges like cost reductions or its preferential use in case of power loss.

The renewable energy potential of Luxembourg is limited by its physical size, the inaccessibility of major water resources and the lack of a geothermal energy resource. As a result the NREAP target of 11 per cent share from renewable energy by 2020 is the second smallest forecast in the European Union.

Barriers to small hydropower development

The main limitation results from the hydrological potential; a very small number of potential sites are available for development. Nonetheless a lack of concrete information on SHP potential is a main barrier for Luxembourg. A clear estimate of the practical potential for expanding hydropower production within Luxembourg is needed, therefore a comprehensive study, using a geographic information system (GIS) based computer model, should be carried out.

4.4.6 The Netherlands

Miroslav Marence, UNESCO-IHE

Key facts

Population	16,854,183 (2014 est.)[1]
Area	41,540 km[2]
Climate	Moderate maritime climate; cool summers (monthly average 23°C) and mild winters (monthly average 0°C) and typically high humidity (75-90 per cent).[12]
Topography	Mostly coastal lowland and reclaimed land (polders); with some hills in the south-east; the highest point is 323 metres above sea level. 26 per cent of the area and 21 per cent of the population are located below sea level achieved by peat extraction and land reclamation.[12]
Rain pattern	Precipitation distributed relatively equally each month (50-90 mm/month). Average annual precipitation is 847 mm.[2]
General dissipation of rivers and other water sources	The major rivers of the Netherlands are the Rhine, flowing from Germany, and its several arms, such as the Waal and Nederrijn Rivers, and the Maas (a branch of the Meuse) and the Schelde (Escaut), flowing from Belgium. 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.[12]

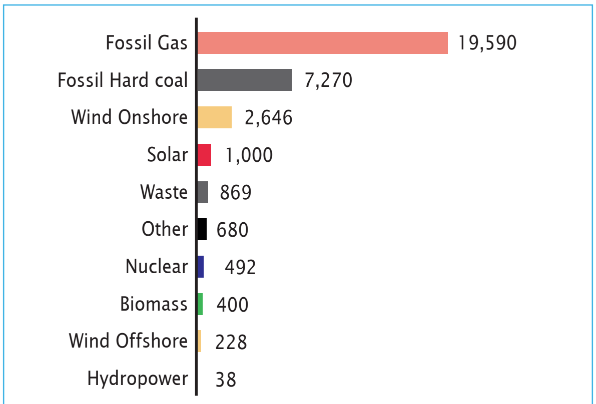
Electricity sector overview

The Netherlands produced a total of 98.6 GWh of electricity in 2013. Integrated in the North-West European electricity market, the Netherlands imported 18.2 GWh, resulting in total electricity supply of 116.8 GWh in 2013.[3] Renewable energy production has grown continuously, approximately by 1 per cent in recent years.

The Netherlands in 2015 had 32.213 GW of installed capacity and the energy mix was dominated by natural gas, hard coal and wind (Figure 1).[13] The country has a full electrification rate and grid availability is guaranteed in the whole country at a level of 99.99 per cent.[4]

FIGURE 1

Installed electricity capacity in the Netherlands (MW)



Source: ENTSO-E (2015)[13]

The renewable capacity in the energy mix represents 9 per cent, which is far from the target of 14 per cent by 2020.[10]

With strong integration in the European electricity market, the energy price for an end consumer is dependent on European price trends. The energy mix, predominantly natural gas, has benefitted from low gas prices, low prices of CO_2 emission allowances, high production capacity in the Netherlands and low electricity prices in Germany.[6] In the longer term, the prices of gas and coal are expected to increase and combined with a decrease in overall capacity this is expected to lead to an increase in the wholesale electricity price towards 2020. The increase of renewable electricity production, particularly after 2020 will have a mitigating impact on the wholesale prices. Over time, wind and solar power will increasingly replace gas and coal fired plants that have higher marginal production costs. This will lead to a steadier average wholesale price after 2020, despite rising coal, gas and CO_2 prices.[6]

Small hydropower sector overview and potential

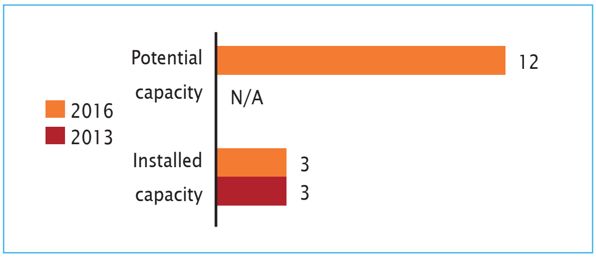
The definition of small hydropower (SHP) in the Netherlands is up to 10 MW. Installed capacity of SHP is 3 MW. While a report issued by Deltares in April 2010 identified the overall hydro potential from rivers at 100 MW,[12] the potential economical capacity considering environmental constraints is estimated to be 12 MW,[9] indicating that approximately 25 per cent has been developed. Between *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has not changed but the potential capacity was not available in the report of 2013 (Figure 2).

A large part of the Netherlands is located in the Rhine–

Meuse-Scheldt delta. The network of rivers is rather complex. The country's topography is dominated by lowlands and reclaimed land (polders). A lot of water resources are available but due to flat topography, hydropower potential is low. Therefore the hydropower potential mostly derives from the existing water management works needed for flood control and navigation measures.

FIGURE 2

Small hydropower capacities 2013-2016 in the Netherlands (MW)



Sources: *WSHPDR 2013*,[11] ESHA[9]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Total installed hydropower capacity in the Netherlands is 37 MW and this is mostly produced with three power plants located on weirs used for navigation.[7]

With approximately 3 MW total installed capacity, SHP accounts for a minor part of the hydropower production (less than 8 per cent).[8] The biggest SHP is Hagestein with an installed capacity of 1.8 MW, the rest of the capacity is distributed among 16 other plants with installed capacity of less than 0.2 MW.

By 2020, the aim is to have a total of 25 plants. To achieve this, many small watermills could be reactivated. Additional potential is found in the numerous sluices and weirs with heights between 1 and 3 metres where low head turbines as well as screw turbines could be installed.

In addition to the hydropower plants, the country has the possibility for tidal SHP to be installed on costal structures that regulate water outflow and on 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. From autumn 2015, the tidal turbines installed in the storm-surge barrier in Oosterschelde will be operational with total capacity up to 1.2 MW.

Renewable energy policy

The European directive on renewable energy requires the Netherlands to meet 14 per cent of total energy consumption from renewable sources by 2020, including at least 10 per cent renewable energy in transport. Currently the share of renewable energy is 9 per cent, and it is not clear if the Netherlands will be able to meet its 2020 targets.

The production of renewable energy will be promoted with the following instruments:[4]

- Sustainable Energy Incentive Scheme Plus (SDE+);
- Obligation to use biofuels in the transport sector;
- Co-firing with biomass in coal-fired power stations;
- Import of renewable energy.

The growth should mainly be sourced from wind, biomass and solar photovoltaic; hydropower is expected to account for less than one per cent of the total

In most of Western Europe the energy producers are separated from the high-voltage grid. 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. The energy sector regulator supervises the energy sector and ensures the conditions for a free energy market.

SHP is mainly supported by the operating grant of the *Stimulering Duurzame Energie*-Encouraging Sustainable Energy Production (SDE) and the Energy Investment Allowance tax deduction. The SDE+ in 2011 has changed compared to the SDE subsidy that started in 2008. The SDE offers long-term (15 years for hydropower) financial security by covering the unprofitable component of projects. The subsidy is the difference between a basic amount (cost price of the renewable energy) and the energy market price. The Dutch Government determines a maximum SDE+ budget for each year. If this maximum is reached in a certain slot, no SDE+ is available for the next slots. This equates to first come, first serve, and the projects that tender in the first slot (with lower subsidy) have the best chance to get the subsidy awarded.

For SHP plants with a height of less than 5 metres, the SDE provides a maximum of EUR 0.122/kWh (US$0.13/kWh) minus the energy market price for 3,800 hours; for SHP plants with a height greater than 5 metres it is EUR 0.071/kWh (US$0.08/kWh) maximum for 4,800 hours.

Generally the produced energy has to be fed-in the local grid based on the market prices (EUR 0.04-0.05/kWh in 2015) (US$0.05/kWh). In the case of a very small power plant with a grid connection of less than 3*80A, there is the possibility that net metering is allowed. This means that produced energy could be deducted from the totally consumed amount of energy. The small consumer energy price in the Netherlands is in the range of EUR 0.22/kWh (approximately US$0.25/kWh) (EUR 0.06 production costs, EUR 0.12 energy tax and EUR 0.04 VAT). Net metering provides the possibility to get the full consumer price instead of the feed-in price of EUR 0.05/kWh. Net metering is only allowed if the power plant is located on one's own property.

The Energy Investment Allowance tax deduction ensures that 44 per cent of the investment costs can be deducted from the taxable profit.

Barriers to small hydropower development

The main limitation for SHP results from the low hydrological potential in a flat country, but the biggest restriction is receiving permission from local water communities ("*Waterschappen*"), which are reluctant to issue. There are quite a few places where development of an SHP plant could be possible.

In the Netherlands, the development of SHP is nearly halted due to the lobby of fishermen (recreational and professional). It is very difficult to obtain *Waterwet* (water law) and *Natuurbeschermingswet* (nature preservation law) permits, due to new fish mortality requirements. This lobby has resulted in debates in Parliament and the Minister of State has ordered a study in order to determine the effects of the existing SHP and measures for their mitigation. First results show that SHP operators have to install fish guidance systems if the decision will be fully in favour of nature and fishery protection measures, which might result in closing or decommissioning most SHP in the Netherlands. However, administrative barriers are not really a problem in the Netherlands because the severity of the topographical barriers to the development of SHP. In addition, the fishermen lobby's implementation of the Water Framework Directive complicates the development.

It is therefore recommended to carry out a comprehensive study, using a geographic information system (GIS) based computer model in order to provide a clear estimate of the practical potential for expanding hydropower production, including SHP within the Netherlands.

4.4.7 Switzerland

Stefano Basso, Eawag – Swiss Federal Institute of Aquatic Science and Technology

Key facts

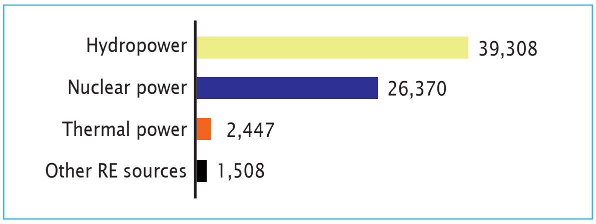
Population	8,306,200
Area	41,285 km²
Climate	Temperate, but varies with altitude: cold, cloudy, rainy and snowy winters; cool to warm, cloudy, humid summers with occasional showers.[3] Annual average temperature for the years between 1981 and 2010 ranges from –9 to 15 degrees Celsius, depending on the location.[7]
Topography	Mostly mountains (Alps in the south, Jura in the northwest; highest point is Monte Rosa at 4,634 metres above sea level), a central plateau of rolling hills, plains and large lakes.[3]
Rain pattern	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; approximately 1,000-1,500 mm/year in the lowland north of the Alps; between 500 and 700 mm/year in Valais and Graubünden regions. The amount of precipitation during summer is nearly double that of winter (except in the Canton of Valais). At the altitude of 1,200-1,500 metres above sea level, precipitation during winter usually occurs as snowfall.[6] Runoff: the share of rainfall available for runoff depends on evapotranspiration. In Switzerland, the potential evapotranspiration decreases with elevation going from the central plateau to the alpine areas, due to decreasing temperature and less intensive land use. About two thirds of the water evaporated in the Alps forms clouds when ascending and rains down again regionally, especially during summer.[7]
General dissipation of rivers and other water sources	Rivers exhibit a variety of runoff regimes, which mainly differ depending on the role played by snow and ice storage in the contributing catchment. Snow influence is negligible in the central plateau, and it only slightly affects peak runoff in the Jura. Alpine Rivers instead exhibit peak runoff during spring and summer seasons, as a result of snow melting and water release from glaciers.[7]

Electricity sector overview

The main sources of electricity in Switzerland are hydropower and nuclear power, respectively accounting for 56.4 and 37.9 per cent of the total production, which amounted to 69,633 GWh in 2014.[2] Production from thermal power plants accounts for 3.5 per cent of the total, while the remaining 2.2 per cent comes from other renewable sources (biomass, wind, biogas, photovoltaic) (Figure 1). The total consumption for 2014 was 61,787 GWh.[2] However, electricity supply during winter depends on imports (between 2,000 and 4,000 GWh in the past 11 years).

FIGURE 1

Electricity generation by source in Switzerland (GWh)



Source: Bundesamt für Energie BFE[2]

In 2011 Switzerland decided to gradually withdraw from the use of nuclear energy. Consequently, a long-term energy policy (Energy Strategy 2050) was drafted in order to guarantee a secure electricity supply. This strategy focuses on increasing energy efficiency, expanding renewable energy use, undertaking an active foreign energy policy and, where necessary, electricity production from fossil fuels.[9] Renovation and expansion of the grid infrastructure is also among the objectives of the strategy, since most transmission lines are more than forty years old, and not designed to handle high numbers of decentralized producers feeding electricity into the grid. The electrification rate is 100 per cent.[19]

Currently, 604 hydropower plants with a capacity of at least 300 kW operate in Switzerland.[12] Approximately 45 per cent of the hydropower production (25 per cent of the total electricity production) comes from run-of-river plants and 55 per cent (32 per cent) from storage plants.[2] The alpine areas of the country (namely cantons Uri, Graubünden, Ticino and Valais) generate the most hydro-electricity. The hydropower market is worth around CHF 1.8 billion (approximately US$1.85 billion),[12] and therefore constitutes an important part of the Swiss energy industry. Nonetheless, the federal government wants to further promote the use of hydropower. The Energy Strategy 2050 plans an increase of hydropower efficiency and new production equal to 1,500 GWh (3,200 GWh under optimal economic and social conditions).[4,9] Moreover, new pumped-storage installations are planned to increase energy storage and production flexibility. In 2014, the cumulated capacity of hydropower plants under construction was 2,464 MW. These plants will add 416 GWh to the national electricity generation.[2]

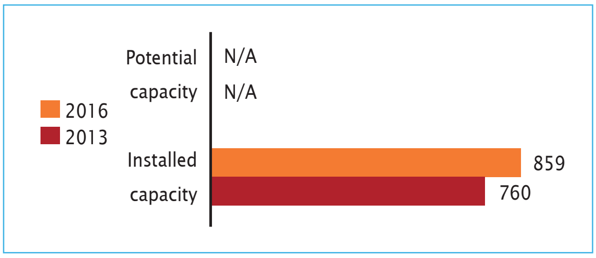
The importance of other renewable sources in the Swiss energy mix is expected to increase, especially because the new energy strategy primarily ascribes increments of renewable energy production to solar and wind technologies. However, while wood and biomass, ambient heat, small hydropower (SHP) and wind are already available and are economically attractive options, photovoltaic and geothermal potentials will not be fully exploited within thirty years, primarily for economic reasons.[13] In Switzerland electricity is exchanged on a market. Therefore, a single tariff system is not applied.

Small hydropower sector overview and potential

Switzerland's definition of SHP is up to 10 MW.[14] Installed capacity of SHP in Switzerland is approximately 859 MW (2010 estimate). The available potential (estimated to prepare the Energy Strategy 2050) is officially reported in terms of production, and it amounts to 1,300 GWh. Data available in the 2013 and 2016 World Small Hydropower Reports indicate a 13 per cent increase of the installed capacity (Figure 2).

FIGURE 2

Small hydropower capacities 2013-2016 in Switzerland (MW)



Sources: SFOE,[13] *WSHPDR 2013*[20]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The overall number of SHP plants in operation in the country is not precisely known, due to a of lack of statistics on installations smaller than 300 kW.[18] Estimates from 2010 report 1,378 plants, with overall installed capacity of 859 MW and annual production of 3,770 GWh.[5] This represents 5.7 per cent of the national electricity production and 10.1 per cent of the hydropower share.[5,13] Among these small plants, an estimated seven hundred have installed capacity below 300 kW and account for only 1 per cent of the hydropower production.[5] This group represents the remaining of a high number of small installations (about 7,000) operating in Switzerland at the beginning of the 20th century, which could be refurbished and contribute to the growth of small hydroelectricity production. However, the most suitable sites are already utilized (in fact, 461 plants have been built or refurbished since 2006 due to the introduction of a feed in tariff).[17] and controversies on the convenience of exploiting the remaining potential are ongoing.

New technologies allow harvesting hydraulic energy on existing infrastructure (e.g. fresh and waste water networks, tailrace channels). The exploitation of these sources benefits from social acceptance, and the required engineering advances (e.g. development of new turbines) are supported by the federal authorities and favoured by existing industrial competences in this field.[18]

The available potential of small scale hydropower was estimated during the preparation of the Energy Strategy 2050. Under present conditions, it amounts to 1,300 GWh; the overall SHP production would thus reach 5,100 GWh in 2050.[9] If improvements of economic (e.g. financial support) and social conditions (higher acceptance of small plants by the community) occur, the available potential would increase to 1,600 GWh.[4,9] The Small Hydropower Programme of the Swiss Federal Office of Energy aims to promote the exploitation of this potential, connecting all the stakeholders and working closely with trade and industrial associations.[15]

Renewable energy policy

The Swiss energy policy is defined by the energy and water articles in the Federal Constitution, the Energy Act, the CO_2 Act, the Nuclear Energy Act, the Electricity Supply Act, the Water Protection Act, the Hydropower Act and the Federal Act on Hydraulic Engineering.[1,8] In particular, the regulatory framework for renewable energy is defined by the Energy Act, while the Water Protection and Hydropower Acts intervene in the field of hydropower exploitation. Other relevant regulations are the Fishery Act, the Spatial Planning Act, the Environmental and Forestry Protection Acts and the Nature and Cultural Heritage Act.[1]

Energy Strategy 2050, which recently adopted after the decision of withdrawing from nuclear energy, is a milestone in Swiss energy policies. As mentioned, this strategy focuses on the exploitation of energy potential from increased energy efficiency, hydropower and new renewable energy sources.[9] The Swiss Energy Programme is the instrument specifically developed to implement energy and climate objectives of the Federal Government and cantons. In particular, cantons determine strategies for the building sector, sustainable energy supply, energy planning and energy efficiency mobility, and promote efficient use of energy and waste heat by means of incentives. Targets on growth of renewable energy production have been set by the Renewable Energy Action Plan.

Electricity production from renewable energy sources is promoted by the Federal Government through two main economic instruments: feed-in remuneration at cost and one-off investment grants. The feed in tariff at cost bridges the gap between market price and cost borne by producers of electricity from renewable sources. This tariff is available for hydropower (up to an installed capacity of 10 MW), photovoltaic (starting from an installed capacity of 10 kW), wind and geothermal energy, biomass and biological waste, and is applicable for 20 years (10 years for biomass power plants). 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.[10] The actual feed in tariff depends on specific features of the plant, for instance the hydraulic head, type of plants (in or out-stream, installed on wastewater or freshwater supply networks), date of request of the feed-in tariff, starting date of operation or yearly production. One-off investment grants, instead, aim to foster electricity production in small photovoltaic systems (from 2 up to 30 kW) by subsidizing a maximum of 30 per cent of the investment costs. Grants are paid out up to an allocated amount of funds.[11] 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).

Barriers to small hydropower development

Economic and social/environmental barriers for the development of small scale hydropower are effectively addressed in Switzerland, e.g. through the cost-based feed in tariff and the involvement of communities in establishing rivers that will be affected by exploitation.[4] A water platform promoting dialogue among stakeholders was also initiated,[17] and research efforts aimed to address rising questions receive support from the Federal authorities.[18]

However, conflicts still exist between growth of SHP, protection of natural creeks and restoration of impaired river reaches required by *the Water Protection Act*. In particular, the need for a great number of small plants in order to achieve a significant energy production (due to limited energy generation of single plants) raised public concern regarding local and cumulated ecologic impact on small pristine rivers.[18]

Improvement of engineering design of small schemes (often overlooked due to the associated high cost per kWh) and introduction of environmentally friendly solutions in new and existing facilities are required in order to enhance public acceptance.[18] Specifically, 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. Technical, economic and ecologic feasibility should be also assessed in early project phases.[4,18]

Additional barriers result from the complex regulatory context, which for SHP exploitations involve legislations on water and energy, environment and development planning, at federal, cantonal and municipal levels.[4] Energy Strategy 2050 tries to address these issues, by simplifying and harmonizing administrative procedures throughout the whole country. Examples of needed intervention are the establishment of a single contact point for SHP plants (where not yet available), a checklist for projects promoters, the possibility to group applications for several installations along the same river and the expansion of the Small Hydropower Programme of the Swiss Federal Office of Energy.[4]

Finally, regulations of the sector are expected to severely change in the coming years. Uncertainty of future framework conditions currently constitute a key impediment to investments in SHP.[18]

CHAPTER 5
Oceania

Photo from Adobe Stock

5.1 Australia and New Zealand

Niels Nielsen, International Energy Agency

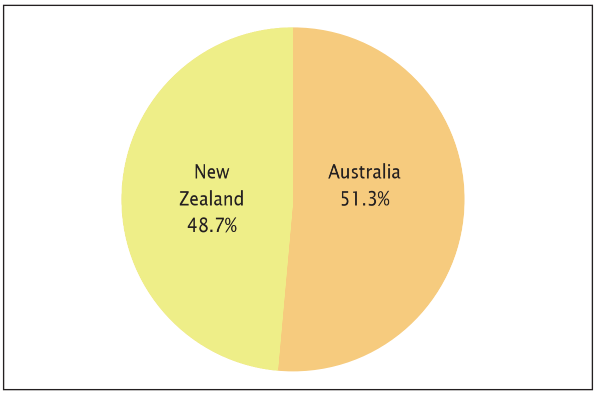
Introduction to the region

Australia and New Zealand are part of Oceania, which is located in the Southern Hemisphere. Australia comprises the mainland continent as well as the island of Tasmania and numerous smaller islands in the Indian and Pacific Oceans. Climactic variations range between temperate, sub-tropical and arid desert. New Zealand comprises the main North and South Islands, as well as numerous smaller islands. The climate varies from temperate to cool alpine in the mountainous regions.

Australia and New Zealand have integrated power systems and electricity markets. Australia's primary electricity generation source is thermal (coal), with hydropower providing the largest renewable energy component. Wind energy is expanding rapidly, with biomass also providing a significant contribution. In contrast, New Zealand's primary electricity generation source is hydropower, with thermal generation providing a smaller contribution. Wind and geothermal power are expanding rapidly, with biomass also providing a significant contribution. An overview of the two countries is shown in Table 1.

FIGURE 1

Share of regional installed capacity of SHP by country



Source: *WSHPDR 2016*[5]

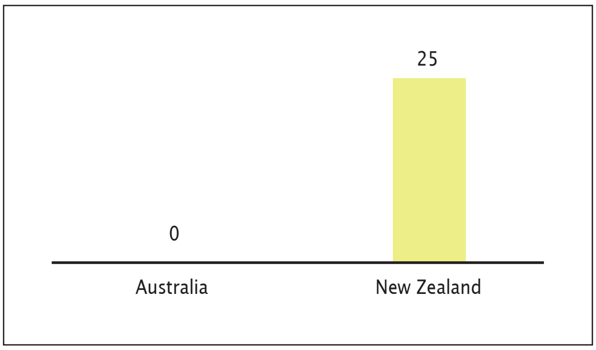
Australia and New Zealand have almost equal shares of regional installed small hydropower (SHP) (Figure 1). Since the publication of the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, the installed SHP capacity has increased by 8 per cent, from 310 MW to 335 MW due to new development in New Zealand (Figure 2).

Small hydropower definition

SHP definitions set by the Energy Efficiency and Conservation Authority (ECCA) of New Zealand are shown in Table 2. Australia has an unofficial SHP definition of up to 10 MW (Table 2).

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for Australia and New Zealand



Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites and/or due to access to more accurate data for previous reporting.

TABLE 1

Classification of Small Hydropower in Australia and New Zealand

Country	Small (MW)	Mini (MW)	Micro (kW)	Pico (kW)
Australia	< 10	—	—	—
New Zealand	1-10	0.01-1	1-10	—

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]

Regional SHP overview and renewable energy policy

Australia and New Zealand have only a small proportion of their hydropower generation supplied by small-scale hydropower and this is not expected to change in the near future.

Installed capacity of SHP in Australia is 172.2 MW. This installed capacity has not changed since 2013. There is no known statistical data on potential small hydro capacity in Australia.

In New Zealand, the installed SHP capacity is about 163 MW, which has increased from 138 MW in 2013. On the other hand, the potential small hydro capacity has decreased from 760 to 662 MW over the same time period. Australia and New Zealand have a large number of dams that do not have any form of electricity generation. These dams could be retrofitted to add hydropower generation. This is an area for future hydropower development in this region.[6]

TABLE 2

Overview of Australia and New Zealand (+ % change from 2013)

Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Australia	23.5 (+6.7%)	10 (0pp)	100	44,444 (-9.5%)	235,200 (+15.2%)	7,333 (-6.7%)	17,576 *(+44.0%)
New Zealand	4.5 (+3.9%)	13 (0pp)	100	9,637 (-1.1%)	42,231 (-2.1%)	5,263 (+0.2%)	24,113 (-2.8%)
Total	**28.0 (+6.2%)**	—	—	**54,081 (-8.1%)**	**277,431 (+12.2%)**	**12,596 (-3.9%)**	**41,689 (+12.5%)**

Sources: Various[1,2,3,4,5,6]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*. An asterisk (*) indicates exclusion of pumped storage.

TABLE 3

SHP up to 10 MW in Australia and New Zealand (+ % change from 2013)

Country	Potential (MW)	Planned (MW)	Installed capacity (MW)	Annual generation (GWh)
Australia	N/A	N/A	172.2 (0%)	N/A
New Zealand	622 (-18%)	N/A	163.2 (+18.2%)	538
Total	—	—	**335.2 (+8.1%)**	—

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

SHP generation can also be added to existing water control facilities such as barrages, weirs, canals and conduits. These often have very low hydraulic head, so they require the use of specific low head (or in-stream flow) technologies. There are also opportunities to retrofit water supply and waste water schemes that have significant hydraulic head.[6]

For Australian renewable energy sources, wind and solar energies are expected to play a much larger role in reaching the renewable energy targets than SHP. Some 30 to 50 major solar projects are in various stages of implementation while 12 GW of wind projects are being planned over the next decade.

While New Zealand has more than 600 MW of SHP potential, most of the viable mini-hydro opportunities with capacities between 0.1 and 5 MW have been developed in the country. Development of other sites is not likely with the low wholesale price of electricity and the lack of financial support mechanisms making technically feasible sites economically unsound.

Barriers to small hydropower development

There are many greenfield sites that are physically suitable for small-scale hydropower development in Australia and New Zealand. However, many of these are in protected areas or are linked to significant potential environmental and social issues, competing uses for water and would require a long and expensive consenting process. Moreover, the other main barrier to development is economical, with costs for new generation higher than market prices, even with renewable energy credits. Perhaps the only likely scenarios for new small hydro development are as part of a multi-purpose development such as irrigation schemes or industrial or domestic water supply initiatives.

5.1.1 Australia

Marcis Galauska, International Center on Small Hydro Power; Paul Bryce and Peter Vail, APACE VFEG (Village First Electrification Group)

Key facts

Population	22,751,014[1]
Area	7,741,220 km[2]
Climate	Australia has a great variety of climate types, ranging from equatorial and tropical, to temperate. While the southern regions have four seasons typical of a temperate zone, the northern tropical regions have two seasons, wet and dry. The wet season, or monsoon season, typically lasts six months, from November to March, and has average temperatures between 30°C and 50°C. The remainder of the year is the dry season, which sees average temperatures of 20°C. The southern cities such as Sydney, Canberra and Melbourne are located in the temperate zone. The average minimum and maximum temperatures for summers are 16°C to 26°C and for winters, 6°C to 14°C.[2]
Topography	The western plateau is characterized by deserts and plains while the more fertile plains are located in the central and south-east regions. Most of the country is less than 600 m above sea level, and the highest point is Mount Kosciuszko, at 2,229 m.[1]
Rain pattern	In the Australian tropical zone, the monsoon season lasts about six months, between November and March. The dry season lasts about six months, usually between April and October. The average rainfall is approximately 534 mm but there are great variations, depending on the climate zone. The driest month is September, with an average of 19.6 mm of rainfall, while the wettest month is February, with 89.5 mm.[1]
General dissipation of rivers and other water sources	The longest river in Australia is the Murray-Darling (2,508 km), which begins in Queensland and flows through New South Wales and Victoria to South Australia. The Snowy River has been equipped with multi-purpose hydroelectric power plants from which part of the river is used to irrigate land along the Murray and Murrumbidgee Rivers. The major tributaries of the Murray River include the Murrumbridgee River (1,485 km) and the Darling River (1,545 km). Many smaller rivers have irregular flows due to high evaporation rates (less than 20 per cent of rainfall ends up in the river systems).[3]

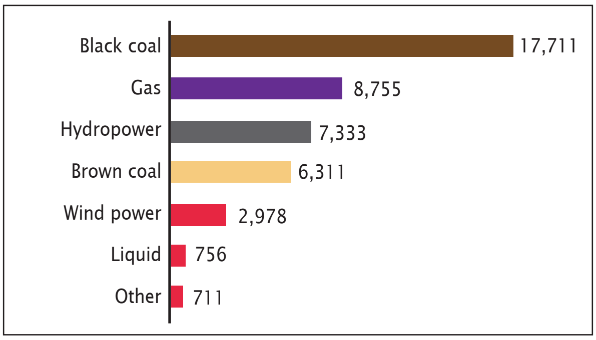
Electricity sector overview

In 2014, the total installed capacity was 44,444 MW, comprising black coal 17,711 MW (39.4 per cent), natural gas 8,755 MW (19.7 per cent), hydro 7,333 MW (16.5 per cent), brown coal 6,311 MW (14.2 per cent), wind 2,978 MW (6.7 per cent), oil 756 MW (1.7 per cent) and other 711 MW (1.6 per cent) (Figure 1).[4] Electricity generation was approximately 235,200 GWh, with almost 75 per cent of the electricity generated using brown and black coal. The electrification rate in Australia is 100 per cent.[4,5] The eastern and southern states have one of the longest interconnected grids in the world. It is a combination of state- and privately-owned infrastructure assets and spans about 4,500 km. This grid services Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania. The wholesale market for electricity supplied via this grid is managed through the National Electricity Market (NEM).

The transmission and distribution networks in Western Australia, the Northern Territory and Mount Isa in Queensland operate separately from the NEM.[7]

FIGURE 1

Installed electricity capacity in Australia (MW)



Source: Australian Energy Regulator [4]

For the major Australian wholesale electricity market, the NEM oversees the sale of bulk electricity by generators to electricity retailers and large enduse customers in southern and eastern Australia. Retailers can sell electricity to all end-use customers down to the household level, i.e. all customers are contestable. Small customers can choose any registered retailer, and prices are becoming progressively unregulated.[13,14] Large customers may purchase electricity directly from the wholesale spot market or under competitive retail contracts, and they generally do so. There are no controls on prices under competitive retail contracts for either small or large customers.[8] By and large, states are at different stages of unbundling and privatizing generation and retailing. However, the State remains the sole licensed transmitter and distributor.[9]

Given the abundance of coal supplies near centralized thermal power stations, the bulk cost of electricity has traditionally been relatively low. However, the cost to the consumer has changed markedly in recent years, particularly since the creation of a single energy regulator (AER) in 2005. Significant sums have been invested in the five years from 2009 to 2014 in the network infrastructure under a regulated and guaranteed investor return of 10 per cent.[15] Profits per connection have doubled between 2008 and 2015. More than half the current consumer's electricity bill now comprises network charges, while the bulk cost of the energy itself has gradually dropped due to solar and wind power supply increases.

Since 2010, energy demand has been decreasing due to the increase in network prices and the sudden increase of residential solar installation, which now represents about 1.4 million households. There was potentially between 7,650 MW and 8,950 MW of surplus capacity across the NEM in 2014 and 2015. Approximately 90 per cent of this was in New South Wales, Queensland and Victoria. Even though there is no prospect of new power capacity requirement in the foreseeable future, the Bureau of Resource and Energy Economics predicts an increasing mismatch between the high degree of vested infrastructure and the behaviour of the consuming market. The abundance of solar resources in Australia, the very high network prices currently established and the high market penetration of residential solar installation are combined factors suggesting that 2.4 million households will be equipped with solar panels and storage installations by 2030.[6]

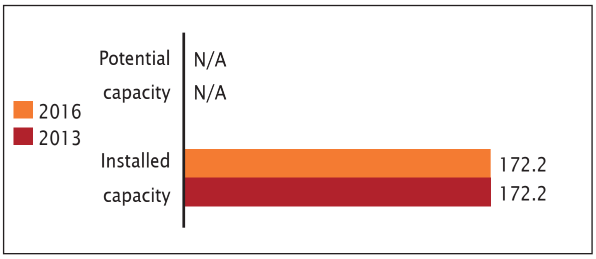
The Bureau of Resource and Energy Economics concluded that Australian household electricity prices for the year ending June 2010 was 0.1938 AUD/kWh (approximately US$0.142/kWh) as calculated by the Australian Energy Markets Commission (AEMC) in November 2010. An AEMC report published in November 2011 reported average household electricity prices for the year ending June 2012 were AUD 0.248/kWh (approximately US$0.182/kWh), indicating an increase of approximately 28 per cent.[9]

Small hydropower sector overview and potential

The definition of SPH in Australia is up to 10 MW. Installed capacity of SHP is 172.2 MW. According to the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed and potential capacities have not changed from 2013 to 2016.

FIGURE 2

SHP capacities 2013-2016 in Australia (MW)



Source: *WSHPDR 2013*[17]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

Australia has around 60 SHP plants. The country's first was in Mooring, Tasmania (three units, with each at 0.2 MW), and was commissioned in 1907. Five other SHP plants built between 1926 and 1928 are still operating. Between the 1950s and 1960s, four additional SHP plants were built. Only one hydropower plant built in 1960 has been re-commissioned in 1983. Between 1983 and 2010, over 50 SHP plants were built and they are still currently operating. There are now approximately 60 operational SHP plants in Australia with an installed capacity between 110kW and 10 MW each and they represent a total installed capacity of 172.2 MW.[10] The majority of suitable hydro sites have already been assessed and developed. Hence opportunities for new development are limited. In coming years, most of the activity in the sector will be about upgrading and refurbishing existing mini hydropower plants.[11]

Renewable energy policy

The renewable energy target (RET) is a Federal Government policy designed to ensure that at least 33,000 GWh of electricity is produced form renewable sources. The RET was reviewed by the government and was revised in June 2015 from 41,000 GWh to 33,000 GWh.

The key points of the policies are as follows:

- Delivering 33,000 GWh will require the installation of approximately 6,000 MW of new renewable energy capacity.
- 30 to 50 major projects are likely to be built in the next five years to meet this target along with hundreds of medium-scale solar projects from commercial and industrial businesses eager to develop their own electricity production and manage their consumption.
- The 33,000 GWh target represents enough electricity to power the equivalent of at least five million homes for a year.
- The revised target is expected to create more than US$40.4 billion worth of investment and more than 15,200 jobs.[12]

Australia has vast renewable energy resources which have largely not been developed (new South Wales, Tasmania and Victoria alone have more than 10 GW of RE potential).[18] The wind power industry is the most attractive renewable resource, representing approximately 12 GW planned for development within the next decade. There has been rapid growth in the use of domestic solar power generation in recent years, in particular in South Australia where 26 per cent of households have rooftop PV systems.[18] There is also significant potential for developing geothermal energy. Ocean energy (wave and tidal power) is a new potential source of energy. There is an increasing interest in ocean energies, with some pilot plants coming into operation and a tidal energy project in the Kimberely region, where the tide has a 15-m amplitude. Plants between 40 MW and 400 MW are being studied.[10]

In contrast to the residential market, there are a number of regulatory and financial barriers that have restricted the application of renewable energies such as solar, wind and small/mini/micro hydro for the commercial and industrial market.[16] Hydroelectric investments face multiple rules that reflect the historical applications of large hydropower regulations in a dry continent. New applications for hydropower plants of smaller scales, such as the run-of-river types, have to cope with expensive transaction costs, such as Environmental Impact Statements, which are often more expensive than the installation construction costs. Residential solar projects are two times more expensive (capital costs per kilowatt) than renewable energy projects at a commercial scale, whether solar, wind or hydro.[17] However, investment returns are much lower unless the output can be directly consumed on-site since feed-in-tariffs (FITs) are unattractive and there is no regulatory permission for amalgamating small consumers. A virtual net metering trial in Northern NSW to reflect the actual load on the network may show a way for energy retailers to apply lower network charges for nearby consumers.[19]

Barriers to small hydropower development

The barriers to SHP developments are as follows:

- Water availability is a key constraint for future growth in hydroelectricity generation, in particular since new large-scale hydro projects are not planned.
- The majority of suitable hydropower sites have already been developed.
- Development of other renewable energy resources is a priority, particularly wind and solar PV, as public opinion does not favour hydroelectric generation.

5.1.2 New Zealand

Mark Pickup, Ministry of Business, Innovation and Employment

Key facts

Population	4,509,700[1]
Area	271,000 km^2
Climate	The New Zealand climate is complex and varies from warm sub-tropical climate in the far north to cool temperate climates in the far south, with severe alpine conditions in the mountainous areas. Mean annual temperatures range from 10°C in the south to 16°C in the north. The coldest month is usually July and the warmest month is usually January or February.[3]
Topography	New Zealand comprises two main land masses and numerous small islands and its terrain is predominantly mountainous and hilly with some large coastal plains.[4]
Rain pattern	The west coast of the South Island is the wettest area of New Zealand whereas the area to the east of the mountains, just over 100 km away, is the driest. Most areas have between 600 and 1,600 mm of rainfall spread throughout the year with a dry period during the summer. Over the northern and central areas, there is more rainfall in winter than in summer, whereas for much of the southern part, winter is the season of least rainfall.[3] On average, February is the driest month with 105 mm of rainfall, while June and August both see more than 160 mm.[13]
General dissipation of rivers and other water sources	New Zealand has an extensive network of freshwater systems including mountain streams, braided and meandering rivers, lakes and groundwater resources of varying sizes and, in some cases, seasonally fed by snow and glacial melt. Demand for fresh water is increasing in some regions and cities, and shortages can be felt at certain times of the year. The national weekly water allocation for irrigation, households, manufacturing and other uses nearly doubled between 1999 and 2010. Hydropower generation also uses large volumes of freshwater and can affect the availability of freshwater downstream.[4] Eight of the 10 biggest rivers are located on the South Island. New Zealand is dotted with storage reservoirs (artificial lakes or natural lakes with raised water levels) ranging in size from small farm dams to the 7,500-hectare Lake Benmore. Many of the larger reservoirs have been created for generating hydroelectricity. There are three main hydroelectric storage lakes in New Zealand, which hold 70 per cent of the water used to generate electricity. Lake Pukaki has the largest storage (around 35 per cent of the national storage), followed by nearby Lake Tekap and by Lake Taupo in the central North Island.[4]

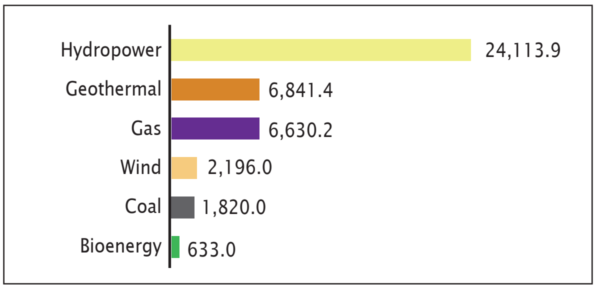
Electricity sector overview

In 2014, 42,231 GWh of electricity was produced in New Zealand with a total installed capacity of 9,637 MW. New Zealand operates a competitive wholesale market for electricity governed by the Electricity Industry Participation Code, which is overseen by the market regulator—The Electricity Authority. Since 1987, a step-by-step industry reform has led to the separation of the monopoly elements of generation, transmission, distribution and retailing to create competitive markets in energy generation and electricity retailing, while imposing regulation on the natural monopolies of transmission and distribution. Hydropower accounts for nearly 57 per cent of national electricity generation (Figure 1). Most hydropower energy is generated in the South Island and all geothermal generation is located in the North Island.[4]

The electricity supply rate is currently around 80-81 per cent renewable and it is government policy for 90 per cent renewable to be achieved by 2025. Hydropower generation has been a part of the country's energy system for over 100 years and continues to provide the majority of its electricity needs. Currently, there is over 5,000 MW of installed hydro capacity. The majority of it is found in the South Island. Geothermal generation has, for a long time, been an integral part of New Zealand's electricity landscape, beginning over 55 years ago with the opening of the Wairakei power station in November 1958.

FIGURE 1

Electricity generation in New Zealand (GWh)



Source: Ministry of Business, Innovation and Employment[5]

Geothermal generation is around 15 per cent of the total electricity generation with installed geothermal capacity situated in the Taupo Volcanic Zone in the central North Island. Wind generation has grown quickly as a source of electricity and now makes up around 5 per cent of the total electricity generation. The first wind farm, Hau Nui, was commissioned in 1997. Most wind farms are located in the North Island. This includes the country's two largest farms, Tararua Wind Farm and West Wind Makara, which are located in the lower North Island. Electricity generation from the combustion of coal, oil and gas provides baseload, backup and peaking electricity supply. Generation from these fuels is around 20 per cent of the total electricity generation. Most thermal plants are found in the North Island, close to domestic coal, oil and gas resources.

Around a third of electricity demand is from households and over a third is from industrial sectors. The majority of industrial electricity demand is from the wood, pulp, paper and printing sectors and the basic metals sectors, with the Tiwai Point aluminium smelter being the largest single user of electricity in the country. The commercial sectors consume around a quarter of total electricity demand. The remaining demand comes from the transport sectors and the agriculture, forestry and fishing sectors, which consume only a small amount.[6]

TABLE 1

Electricity tariffs in 2014 and 2015 (US$ cents/kWh)

March, Year	2014	2015
Average	38.3	34.9
Residential	23.4	20.5
Commercial	16.1	14.5
Industrial	26.6	22.2
Agriculture, forestry and fishing	16.5	14.4
Mineral and petroleum extraction	18.1	16.2
Food processing	13.6	11.4
Wood pulp, paper and printing	11.8	11.1
Chemicals and basic metals	28.2	22.2

Source: New Zealand Electricity Authority[7]

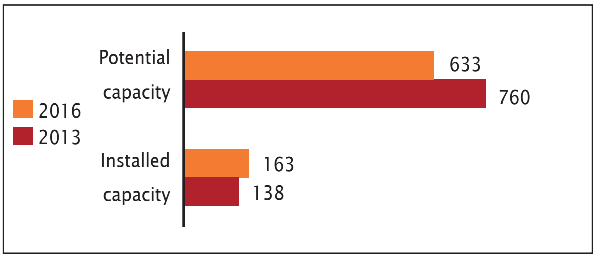
The New Zealand electricity sector operates as a fully competitive market. There are no subsidies for any generation type. The regulator is a government agency and the national grid is a state-owned enterprise. Local lines businesses are a mixture of private- and community-owned trusts, with a few owned by the local government. All generators and retailers are either private or for the three largest generator/retailers mixed-ownership companies with 51 per cent government ownership. The wholesale electricity market is an energy-only market for pricing and dispatch. There is no capacity market or payments. However, there are markets for ancillary services such as frequency keeping and reserves. The Electricity Authority is the regulator for the electricity sector. Its objective under its empowering legislation is to "promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long term benefit of consumer".[6] The Commerce Commission promotes competition in markets, excluding the electricity market, which is regulated by the Electricity Authority. The Commerce Commission does, however, regulate the prices charged subject to quality standards of monopoly elements of the electricity system such as line and transmission distribution businesses.[6]

Small hydropower sector overview and potential

The New Zealand Energy Efficiency and Conservation Authority (EECA) has classified SHP to be in the capacity range of 1 MW to 10 MW, mini hydropower in the range of 10 kW to 1 MW and micro hydropower is usually less than 10 kW and used for domestic applications. SHP (less than 10 MW) contributed 2.2 per cent (538 GWh) to the overall electricity production in 2014. The total SHP installed capacity represents 163.28 MW whereas the total small hydropower (SHP) potential is 622 MW.

FIGURE 2

SHP capacities 2013-2016 in New Zealand (MW)



Sources: Ministry of Business, Employment and Innovation,[5] *WSHPDR 2013*[12]
Note: The comparison is made between data from *WSHPDR 2013* and *WSHPDR 2016*.

The installed SHP capacity is about 163 MW, with annual electricity generation of 538 GWh in 2014. This is based on the summarized information from the New Zealand Electricity Authority on 63 SHP plants. Several reports and studies contain information on hydropower projects, including SHP. The EECA (2004) commissioned a series of studies to assess the renewable energy potential in different regions across New Zealand, including hydropower. Regional summaries of existing and potential SHP projects list a total SHP potential of 622 MW, excluding sites in conservation zones. Environmental Impact Assessments are required for SHP plants. Most viable mini-hydro opportunities with capacities between 100 kW and 5 MW have been developed in the country. A large number of projects are still technically feasible yet not economically viable. It is expected that a few projects could compete with the wholesale price of electricity and may be subjected to resource-consenting issues.[8]

No information is compiled by New Zealand government agencies on SHP in development. There is no financial support mechanism for SHP or for any other renewable energy generation source in New Zealand.

Renewable energy policy

The New Zealand Energy Strategy 2011-2021 contains the target of 90 per cent of electricity to be generated from renewable energy sources by 2025. The economic competitiveness of new renewable electricity generation will be enhanced by a price on carbon. The accompanying New Zealand Energy Efficiency and Conservation Strategy 2011-2016 (NZEECS) consists of the objective of an efficient renewable electricity system supporting the country's global competitiveness. It includes working on system requirements of smaller-scale generation technologies.[9]

The Resource Management Act 1991 (RMA) governs access to natural resources and allows community input in resource allocation decisions. Decisions under the RMA are made at local government or community level. Guidance on RMA decisions can be provided by the central government through the National Policy Statement for Renewable Electricity Generation 2011 (NPS REG), which sets out the objective and policies for renewable electricity generation under the RMA. The NPS came into effect on 13 May 2011 and will drive a consistent approach to planning for renewable electricity generation in New Zealand. It gives clear government direction on the benefits of renewable electricity generation and requires all councils to make provisions for it in their plans. The NPS on Renewable Electricity requires decision-makers (local government) to incorporate provisions in their regional and district plans that recognize the benefits of renewable electricity POLICY E2 for Hydro Electricity states. Regional policy statements and regional and district plans shall include objectives, policies and methods (including rules within plans) to provide for the development, operation, maintenance and upgrading of new and existing hydro-electricity generation activities to the extent applicable to the region or district.[10]

Barriers to small hydropower development

The barriers to SHP development in New Zealand are similar to those faced by other generation developers. All developers are subject to the same application process under the Resource Management Act and connection standards to local or national grids. Renewable energy development is not subsidized so SHP development needs to complete with other renewable alternatives over its economic viability or competitiveness. Furthermore, SHP developments may complete with other uses of water, e.g. irrigation and recreation, or may face water quality concerns. In this regard, a recent development is a National Policy Statement on Freshwater management which is intended to establish criteria for the improvement of water quality in New Zealand. Arguably, this NPS may make development more difficult to the extent that an SHP proposal may have a detrimental effect on water quality.[11]

5.2 Pacific Island Countries and Territories – Melanesia, Micronesia, Polynesia

Guillaume Binet, Engineering Consultant

Introduction to the region

The Pacific Island Countries and Territories (PICTs) include three United Nations designated regions: Melanesia, Micronesia and Polynesia. These regions comprise 22 island countries and self-governing/overseas territories, often known as Oceania, without Australia and New Zealand.

The PICTs have diverse renewable energy resources (e.g. solar, wind, hydropower, geothermal, biomass, tidal, ocean thermal energy conversion) but still remain dependent on imported fossil fuels to meet their energy needs. The large rural populations of those countries face difficult challenges when it comes to rural electrification, with exceptions such as Samoa, which has almost complete coverage. Due to their unique geography, comprising separate, sparsely populated areas separated by long distances, as well as the region's economy nodes, it is difficult to achieve cost savings and in many cases endanger new electricity production projects' viability. An overview of the PICT countries is presented in Table 1.

Significant developments in the region that have occurred since 2013 include:

- The creation or study of renewable energy development plans (such as roadmaps) for the first time for many countries of the PICTs region such as Fiji, New Caledonia, Papua New Guinea (PNG), Vanuatu and Samoa. The energetic transition has become a major topic. They include wind, solar, hydropower and biomass development objectives.
- There are still no renewable energy policies in the Solomon Islands.
- Adoption of the first energy policy in Federated States of Micronesia and the Electricity Act in Samoa which has opened energy production to Independent Power Producers.
- Completion of Asian Development Bank programmes: Promoting Energy Efficiency in the Pacific Phase 2 (Solomon Islands, Vanuatu and PNG) and Promoting Access to Renewable Energy in the Pacific (Cook Islands, PNG, Samoa, Tonga, Vanuatu).[5]

Eight of the 22 countries/territories have adopted small hydropower (SHP). These include Fiji, New Caledonia (self-governing territory of France), PNG, Solomon Islands, Vanuatu, Micronesia, French Polynesia (overseas territory of France) and Samoa. These countries or territories all have a tropical climate, as well as mountainous areas that are suitable for SHP. While New Caledonia and Vanuatu's weather is influenced by trade winds, PNG, Fiji and Solomon Islands are influenced by monsoons and Micronesia has year-round heavy rainfall and typhoons.

TABLE 1

Overview of countries in PICT (+ % change from 2013)

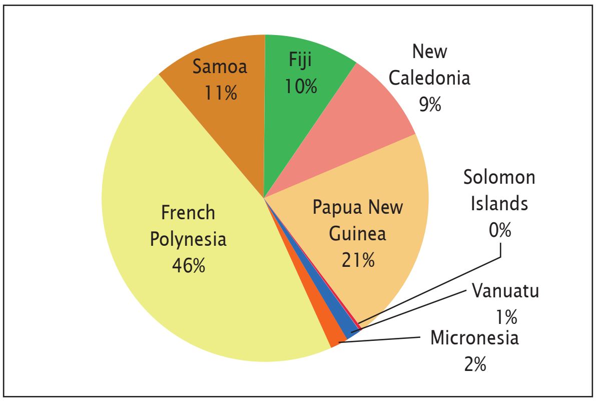
Country	Total population (million)	Rural population (%)	Electricity access (%)	Electrical capacity (MW)	Electricity generation (GWh/year)	Hydropower capacity (MW)	Hydropower generation (GWh/year)
Melanesia							
Fiji	0.91 (+2.2%)	46 (+2pp)	89 (+5pp)	269 (0%)	858 (+7%)	134 (0%)	527 (+16%)
New Caledonia	0.27 (+3%)	30 (-13pp)	59 (-)	495 (0%)	2,400 (+33%)	78 (0%)	280 (-38%)
Papua New Guinea	6.67 (+6%)	87 (0pp)	18 (+6pp)	582 (0%)	3,350 (+13%)	233 (+8%)	N/A
Solomon Islands	0.62 (+7%)	88 (+7pp)	22 (+5pp)	28 (0%)	85 (+9%)	0.258 (-13%) [a]	1 (0%)
Vanuatu	0.28 (+9%)	74 (0pp)	27 (-)	32 (+163%)	80 (16%)	1.2 (0%)	5 (0%)
Micronesia							
Micronesia	0.1 (-4%)	78 (+1pp)	55 [b]	28 (0%)	N/A	2.1 (+5%)	N/A
Polynesia							
French Polynesia	0.28 (+3%)	44 (-5pp)	98 (-)	227 (+19%)	692 (+3%)	47 (0%)	158 (-8%)
Samoa	0.19 (+2%)	81 (+1pp)	99 (+1pp)	35 (-17%)	121 (+10%)	12 (-)	35.1 (-27%)
Total	**9.33 (+5%)**	—	—	**1,696 (+3%)**	**6,893 (+5%)**	**503.658 (+4%)**	**1,006.1**

Sources: Various[1,2,3,4,5,6]
Notes:
(a) The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.
(b) Denotes percentage data taken from the country report in *WSHPDR 2013*.
(c) Per state electrification rates are: Chuuk, 27%; Yap, 67%; Pohnpei, 87&; and Korsae, 98%.[5]

Non-mountainous islands or low-lying atoll islands, such as the Cook Islands, Tuvalu, Kiribati and others, have very little or no hydropower. The hydropower potential of these countries has not been assessed and is not treated in this report.

FIGURE 1

Share of regional installed capacity of SHP by country



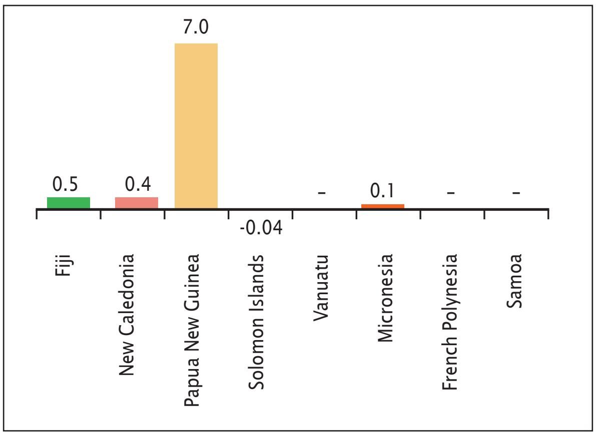
Source: *WSHPDR 2016*[5]

While all five countries in Melanesia use SHP, most countries/territories of Micronesia (Guam, Kiribati, Marshall Islands, Nauru, Northern Mariana Islands and Palau) and Polynesia (American Samoa, Cook Islands, Niue, Pitcairn, Tokelau, Tonga, Tuvalu and Wallis and Futuna Islands) do not use SHP.

Together, French Polynesia and PNG account for almost 70 per cent of the regional share of installed SHP (Figure 1). Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, the installed SHP capacity has increased by 9 per cent from 102 MW to 111 MW (Figure 2).

FIGURE 2

Net change in installed capacity of SHP (MW) from 2013 to 2016 for PICT



Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*. A negative net change can be due to closures or rehabilitation of SHP sites, and/or due to access to more accurate data for previous reporting.

Built on the United Nations Millennium Development Goals, 17 Sustainable Development Goals were defined by United Nations leaders in September 2015, among which is Goal 7 "Ensure access to affordable, reliable, sustainable and modern energy for all". The Sustainable Energy for All (SE4ALL) initiative and more locally its Asia-Pacific hub AP-SE4ALL, is tracking efforts of the region to comply the key targets of Goal 7 through the Global Tracking Framework by 2030. The International Renewable Energy Agency (IRENA) joined this effort with a main target to double the share of renewable energy resources in the energy mix globally and locally within the PICTs. In 2012, IRENA hosted a Pacific Leaders Forum, where leaders from 11 of the PICTs expressed their needs for IRENA to create guidance and foundations for the development of renewable energy in the region. The work of IRENA has been materialized into an energy roadmap and summarized in the *Pacific Lighthouses Renewable Energy Roadmap for Islands* report.[5]

Technologies for wind, solar and biomass projects have become more accessible in the region due to their global maturity increase. Numerous countries and territories of the PICTs region have hence moved toward the deployment of alternative electricity sources in adopting new roadmaps to shape their clean energy future. The Government of Fiji has developed a Green Growth Framework in order to reduce the country's carbon footprint by reaching 80 per cent renewable energy generation by 2018. An independent committee of renewable energy producers has proposed for the government to take the lead in coming up with a new set of goals and recommendations for the country's Investment Programme to reach 30 per cent clean energy production by 2030. Energy goals have been implemented in PNG through the Papua New Guinea Development Strategic Plan (2010-2030). In conjunction with the World Bank, in 2014, the Government of Vanuatu implemented the Vanuatu National Energy Roadmap. The Samoa Energy Sector Plan (2012-2016) is still under implementation and aims to achieve 100 per cent renewable electricity generation by 2017.[5]

Solar energy applications are feeding into the grid in various islands such as Nauru, Niue, Samoa and Tuvalu. It is under development in Fiji, Vanuatu and French Polynesia. Hydropower is contributing considerably to the main grids in Fiji, Papua New Guinea, French Polynesia and Samoa. Wind energy is developed in Fiji, Vanuatu and New Caledonia and geothermal energy applications can be found in Papua New Guinea and Vanuatu. Furthermore, in many PICTs there is still a growing deployment of off-grid systems based on renewable energy.[5]

Small hydropower definition

There is no official SHP definition within the PICTs region but hydropower plants up to 10 MW are commonly considered as SHP plants.

TABLE 2

Classification of SHP in PICT

Country	Small (MW)	Mini (MW)	Micro (kW)	Pico (kW)
Melanesia	—	—	—	—
Fiji	1.5-10	—	—	—
New Caledonia	2-10	—	500-2,000	Up to 500
Papua New Guinea	0.1-10	—	—	—
Solomon Islands	0.5-10	—	—	—
Vanuatu	Up to 10	—	—	—
Micronesia	—	—	—	—
Micronesia	Up to 10	—	—	—
Polynesia	—	—	—	—
French Polynesia	2-10	—	500-2,000	Up to 500
Samoa	Up to 10	—	—	—

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]

Regional SHP overview and renewable energy policy

The significant SHP developments since 2013 in the region are as follows:

- New Caledonia: No SHP developments, although Ouiné (40 MW) has been signed for implementation. One 25 MW site around Mount Panié area is also under study.
- Papua New Guinea: Duvine (3 MW) and Ramazon (3 MW) are under study at the feasibility level.
- Solomon Islands: Tina (20 MW) has its feasibility study completed, several feasibility studies have been undertaken on the Huro and Luembalele Rivers. Fiu (750 kW) has been confirmed for development with sufficient funding.
- Vanuatu: Brenwe (1.2 MW), Wambu (2.2 MW) and Sarakata (upgrade to 1.8 MW) are under development.
- Federated States of Micronesia: Nanpil (upgrade).
- French Polynesia: Papeiha (13.8 MW) is under study and five catchment areas under assessment.
- Samoa: Faleaseela (0.2 MW), Tafitoala (0.5 MW), Faleata (0.2 MW) and Fuluasou (0.7 MW) are being developed.[5]

The total installed capacity of SHP in the eight examined countries is more than 150 MW, while the potential is at least 390 MW. This estimate is limited to the knowledge possible on projects evaluated or confirmed as feasible with a limited assessment of their financial viability. For instance, the Solomon Islands hydropower potential study by Japan International Cooperation Agency has demonstrated a small hydro potential of 326 MW. However, only 11 of the 62 sites are likely to be technically and economically feasible. The Fiji Department of Energy has made a preliminary assessment of 100 sites, but potential is still being studied. Due to new reforms in New Caledonia towards the development of renewable energy projects, information on hydropower potential has been available and shows a significant increase of the potential capacity.[5,6]

It is a difficult task to obtain recent and accurate information on the SHP potential for each country in PICT region. Electricity generation from hydropower plants play an important role in the grid of Samoa (29 per cent), Fiji (62 per cent), Papua New Guinea (20 per cent) and French Polynesia (30 per cent).[5,6]

The development of SHP has been relatively positive in the region since the publication of *WSHPDR 2013*, except for the micro-scale projects of the Solomon Islands where the Appropriate Technology for Community Environment-Village First Electrification Group (APACE-VFEG), an environmental Australian NGO, has ceased developing projects in the country.[5]

There have been many ongoing and flourishing developments and initiatives in the region. A non-exhaustive list is provided below:

- In Papua New Guinea, the Programme of Activities for Renewable Energy has been validated at the United Nations Framework Convention on Climate Change, under the Clean Development Mechanism. This has initiated the development of new SHP plants such as Ramazon (3 MW) and Divune (3 MW).
- In Vanuatu, the Asian Development Bank (ADB), under a Renewable Energy Programme, funded the Talise (75 kW) hydropower project which was completed in 2014, under an Italian-Austrian fund managed by the International Union for Conservation of Nature.
- In Vanuatu, the Scaling-up of Renewable Energy Progra, jointly funded by the ADB will allow a study of the 1.2-MW Brenwe hydropower project.
- A UNDP/GEF funded project called the Pacific Islands Greenhouse Gas Abatement through Renewable Energy Project (PIGGAREP) is still active. It aims to reduce the growth rate of greenhouse gas emissions from fossil fuels in the PICTs through the removal of barriers to the widespread and cost effective use of feasible renewable energy technologies. The project is being implemented in eleven PICTs. The PIGGAREP project activity in the Solomon Islands and Vanuatu completed awareness community consultations and workshops over the Tina and Talise hydro schemes in 2014.

International finance plays an important role in the SHP development in the PICTs region. The ADB has been and still is involved in numerous energy-related development programmes within the region.[5]

TABLE 3

SHP in PICT (+ % change from 2013)

Country	Potential (MW)	Planned (MW)	Installed capacity (MW)	Annual generation (GWh)
Melanesia				
Fiji	14 (0%)	N/A	10.5 (+5%)	N/A
New Caledonia	100 (+270%)	N/A	9.9 (+4%)	N/A
Papua New Guinea	153 (+4%)	N/A	29 (+43%)	N/A
Solomon Islands	11 (0%)	0.75	0.25 (-14%)	1 (0%)
Vanuatu	4.78 (+20%)	3.5	1.3 (0%)	5 (0%)
Micronesia				
Micronesia	9 (0%)	N/A	2.1 (+5%)	N/A
Polynesia				
French Polynesia	98 (+50%)	35.3	47 (0%)	158
Samoa	22 (0%)	1.49	11.9 (0%)	35.1 (-27%)
Total	**411 (+35%)**	**5.7**	**111.95 (+0%)**	**199.1 (-)**

Sources: *WSHPDR 2013*,[6] *WSHPDR 2016*[5]

Barriers to small hydropower development

Beside all those development efforts, several challenges still remain in order to proceed further with SHP development in the PICT region. Finance is a major barrier to the implementation of projects in the region. Many of the countries have unviable financing mechanisms, lack feed-in-tariff regulations, do not possess site-specific water data, lack land and water regulation and have unrealistic land compensation fees as well as high upfront capital cost. Additionally, the region has topographical limitations, protected archaeological and ecological sites, climate destabilization due to climate change and issues over land ownership.

Technically, the PICTs have expressed their strong need to develop local skills during all phases of SHP project development, from reconnaissance survey to concept design, feasibility studies, construction, commissioning and operation. This is to guarantee local capacity building and sustainable maintenance of existing and future plants. For micro hydropower projects which are mostly remote and off-grid, community approaches, such as those developed and implemented by APACE in the Solomon Islands and Vanuatu, will ensure sustainable rural electricity access.

Even though coal and crude oil prices have been drastically decreasing between 2014-2016 and thermal power generation is once again becoming economically attractive, it is important that the PICTs do not divert from their clean energy goals to reduce and eliminate energy production impacts on their fragile and unique ecosystems.

5.2.1 Fiji

Anare Matakiviti, IUCN Oceania energy

Key facts

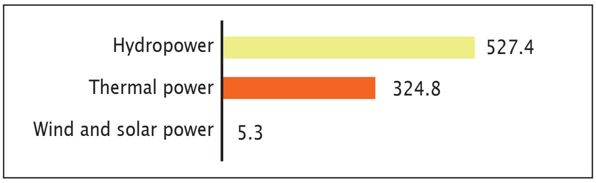
Population	886,450[1]
Area	18,333 km[2]
Climate	The climate is generally categorized as an oceanic tropical marine type with variations over different timescales. It is usually hot and wet during the months of November to April and it becomes cool and dry from May to October.[2]
Topography	The large islands are volcanic with high mountain ranges. The highest mountain is Mount Tomanivi, which is approximately 1,323 m high.[2]
Rain pattern	During November and April, when it is usually wet, rain can be quite torrential and flooding usually occurs. Annual rainfall on the main islands ranges 2,000-3,000 mm on the low-lying areas to around 6,000 mm in the mountainous parts. Typically, the smaller islands receive less rainfall than the two main islands of Viti Levu and Vanua Levu. Rainfall in the smaller islands ranges 1,500-3,500 mm.[2]
General dissipation of rivers and other water sources	On Viti Levu, the largest island, the major river is the Rewa. This river is navigable for 113 km. The island also has other river systems, including the Nadi, Ba and Sigatoka. All of these rivers rise in the island's central mountains. The main river on Vanua Levu is the Dreketi.[3]

Electricity sector overview

In 2013, electricity generation was 857.5 GWh. Hydropower accounted for 61.5 per cent, thermal (mainly diesel) accounted for 37.87 per cent and wind and solar accounted for 0.62 per cent (Figure 1).[4,7]

FIGURE 1

Electricity generation in Fiji (GWh)



Sources: IRENA,[4] FEA[7]

In 2014, installed capacity was 269 MW, with 134 MW from hydropower.[4] Fiji is heavily reliant on imported petroleum products to meet its energy needs. Around 70 per cent of the imported fuels are used in the transport sector and around 20 per cent in the electricity sector. The other 10 per cent is for small commercial and industrial use. The overall electrification rate in Fiji is 89 per cent.[7]

The Fiji Electricity Authority (FEA) is a state-owned electricity utility that owns and operates the electricity infrastructure, including generation and the transmission and distribution network.

The FEA has a natural monopoly in the generation, transmission, transformation and distribution and sale (either in bulk or to individual customers) in any part of Fiji. Given this monopoly status of the FEA in the supply of electricity in Fiji, electricity tariff rates are subject to price control under Commerce (Control of Prices for the Supply of Electricity and Ancillary Services) Order 2012. These include:

- Domestic tariff: Customers are charged a lifeline tariff. For customers consuming less than 85 kWh per month, it is US$0.17/kWh and US$0.33/kWh for every unit above 85 kWh.
- Small business tariff: For business whose maximum demand is less than 75 kW. Customers are charged US$0.39 for the first 14,999 kWh and US$0.41 for each unit above 14,999 kWh.
- Maximum demand tariff: For business whose demand is more than 75 kW. Customers are charged for the total amount of electricity used (kWh), plus a Demand Charge (kW), for the relevant billing period. The demand charge is US$36.57/kW and for the total kWh used, the charge is US$0.29/kWh.
- Other tariff: For institutions and streetlights. Customers include places of worships, primary and secondary schools. Schools are charged US$0.24/kWh for the first 200 kWh and US$0.33 for every kWh above 200 kWh. The charge for places of worship and streetlights are US$0.33/kWh[8]

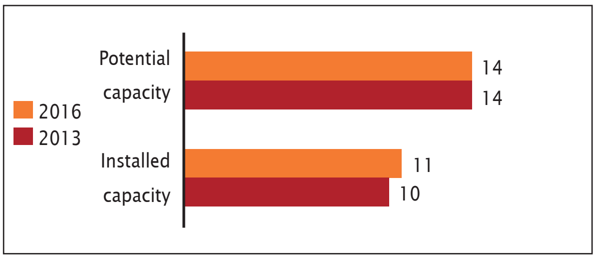
Small hydropower sector overview and potential

There is no uniform definition of small hydropower (SHP) plants in Fiji. For the purpose of this paper, SHP projects have been classified as those 10 MW and below. The installed capacity of SHP in Fiji is approximately 10.5 MW, while the hydropower potential is estimated to be 14 MW. This indicates that 75 per cent has been developed. Between the *World Small Hydropower Development Report (WSHPDR) 2013* and *WSHPDR 2016*, installed capacity has increased by approximately 5 per cent, while estimated potential has not increased (Figure 2).

Through the Department of Energy, Fiji has identified a number of potential hydro sites. Over 100 sites have been identified and preliminary assessments have been carried out at a number of the sites. Table 1 shows the number of SHP projects that have been built in Fiji.

FIGURE 2

SHP capacities 2013-2016 in Fiji (MW)



Sources: *WSHPDR 2013*,[6] Fiji Department of Energy[5]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The Wanikasou hydropower plant (6.5 MW) started operating in 2004. A 700 kW hydro project is currently under construction at Somosomo, on Taveuni Island near Vanua Levu.[5]

TABLE 1

Micro and small hydro projects in Fiji

#	Project	Capacity	Location (Island)	Year installed
1	Vaturu	3 MW	Viti Levu	2004
2	Wainiqeu	800 kW	Vanua Levu	1992
3	Nasoqo	4 kW	Viti levu	1984
4	Bukuya	100 kW	Viti levu	1982
5	Vatukarasa	3 kW	Viti levu	1993
6	Kadavu koro	20 kW	Kadavu	1994
7	Muana	30 KW	Vanua Levu	1999
8	Buca	30 KW	Vanua Levu	2012
9	Wanikasou	6.5 MW	Viti Levu	2005

Source: IRENA[4]

Small and micro hydro projects are included as options for rural electrification schemes under the Fiji Government's Rural Electrification Policy. Rural electrification schemes are heavily subsidized by the Government. Communities are required to pay a 5-per-cent contribution, with the Government paying the balance. In the last 30 years, only eight SHP schemes have been built (Table 1). This is attributed mainly to the high costs associated with constructing hydro schemes. In most cases, the Government contribution for a hydro installation is usually met by a donor agency.

Renewable energy policy

Fiji has a number of renewable energy sources that have the potential to be developed into power projects. Solar energy is in abundance and a number of solar PV projects (both off and on grid) have been installed, with the former used mainly for rural electrification. There is a 10 MW wind farm connected to the national electricity grid and managed by the FEA. Biomass energy, in particular bagasse and woodchips, is also used to generate power and feed the national electricity grid. Both plants are operated by independent power producers with the bagasse-fed plant operated by the Fiji Sugar Corporation and the woodchip-fired plant operated by Tropic Wood Fiji Ltd.

Fiji has developed a Green Growth Framework (GGF) that aims to "restore the balance in development that is sustainable". One of the guiding principles of the GGF is to reduce Fiji's carbon footprint at all levels. The GGF is expected to drive the development of renewable energy projects in the power sector, particularly with the FEA declaring a 90 per cent target of renewable energy generation by 2018.[5,4]

Barriers to small hydropower development

In addition to the high cost of hydropower development in Fiji, other socio-economic and environmental considerations also contribute to the slow uptake. The major barriers in the development of small and micro hydro projects include:

- Limited resources to undertake full feasibility studies of sites that have been identified.
- Absence of a viable financing mechanism.
- Absence of an SHP industry in neighbouring countries.
- Extreme climatic events (heavy and intense rainfall, floods, cyclone, landslides etc.) make monitoring and site assessment challenging as they are time and resource consuming.
- Lack of incentives for private sector participation in assessment and development of sites, as well as lack of interest in project implementation.
- Limited access to finance for private project developers. Loans are very difficult to obtain, interest rates are high and there is minimal government support.

- Most potential SHP projects are located in unproductive areas like subsistence communities. The sustainability of small and micro hydropower schemes is at risk as the rural communities have poor affordability, with limited and uncertain cash income.
- Absence of appropriate economic policy to support SHP development.
- Land tenure issues. Landowners demand unrealistic resource use compensation.
- Potential impacts on resources for cultural purposes sometimes act as a deterrent for the use of sites.
- Lack of technical and regulatory support to review opportunities for using tax and fiscal mechanisms, in order to encourage greater up-take of renewable energy projects.
- Lack of technical expertise and resources to handle new technologies.
- Insufficient incentives for a wider participation of the population in renewable generation.

5.2.2 New Caledonia

Guillaume Binet, Engineering Consultant

Key facts

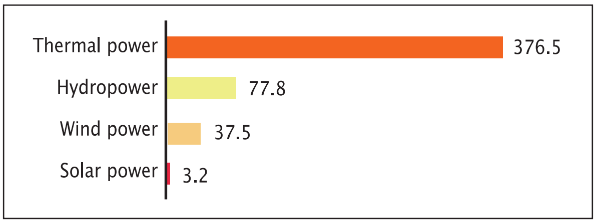
Population	268,767[1]
Area	19,103 km^2
Climate	New Caledonia is located in the tropics, just north of the Tropic of Capricorn. Geographically isolated and subjected to trade winds, it enjoys a relatively temperate climate that can be described as tropical oceanic. The annual change in the position of the sub-tropical high pressure belt and bass inter-tropical pressures determines two main seasons separated by two inter-seasons: the hot and humid hurricane season (November to April), a season of transition (April to May), the cold season (May to September), with the Coups d'Ouest (westerly winds), as well as the dry season (September to November), when the trade winds blow continuously.[3]
Topography	Oriented south-east to north-west at approximately 400 km across and 50 km wide, Grande Terre has a mountainous axis (Chaîne Centrale) over its entire length, with Mount Panié (1,628 m above sea level) in the north and Mount Humboldt (1,618 m above sea level) in the south. On the east coast of the main island, the Chaîne Centrale is very exposed to trade winds and ends with steep slopes falling directly into the sea. To the west, it is bordered by plains, hills and small plateaus protected from prevailing winds. The south is characterized by a plateau.[3]
Rain pattern	Rainfall on the main island varies greatly, depending on the terrain and wind exposure. Rainfall is hence the most important in the mountains to the north-east and south, with a mean rainfall of 3,000-2,500 mm/year. The rain on the western plains is lower, at 1,000-1,500 mm/year.[3]
General dissipation of rivers and other water sources	Sedimentation of rivers due to mining activities has been an ongoing concern for flow patterns. However, the 61 rivers still maintain healthy flows, depending on seasonal variations. The Ouaméni, Ouenghi and Tontouta Rivers are building mangrove-fringed deltas, while the Néhoué and the Poya have built intricate mangrove-fringed deltas bordered by tidal mudflats. Energy dissipaters such as gabion baskets, as well as wood and stone weirs for small creek on mining sites, are very common. These help mitigate the erosion of gullies and excavated lands.[4]

Electricity sector overview

Electricity production in New Caledonia is mainly driven by the increasing metallurgic industry demand, which represents 68 per cent of its total electricity consumption. The installed electricity generation capacity in 2014 was 495 MW, with a total electricity production of about 2,400 GWh.[19]

FIGURE 1

Installed electricity capacity in New Caledonia (MW)

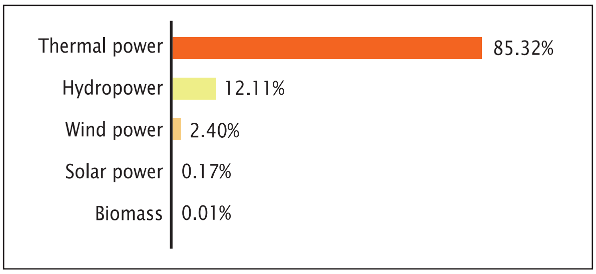


Source: Institut de la Statistique et des Etudes Economiques Nouvelle-Calédonie (ISEE)[19]

Electricity is mainly generated by thermal plants (85 per cent). Hydropower sources (micro, small and large) represent only 280 GWh (12 per cent) out of the total production (Figure 2).[19]

FIGURE 2

Electricity generation in New Caledonia (%)



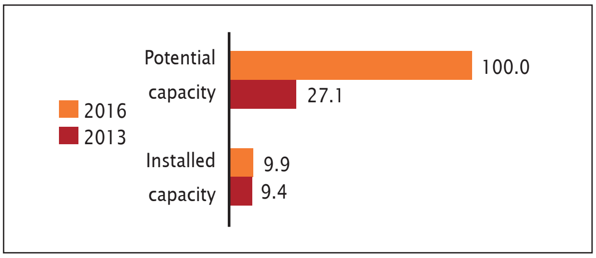
Source: Institut de la Statistique et des Etudes Economiques Nouvelle-Calédonie (ISEE)[19]

The energy production in New Caledonia is closely related to the nickel ore extraction and processing activities from the three main nickel ore processing plants located on the main island of Grande Terre. These plants are Koniambo Nickel SAS in the North Province, La Société le Nickel (SLN) in Nouméa Region and Vale NC in South Province. Each of those sites requires continuous energy supply to allow non-stop production all year long. In 2014, about 1,600 GWh out of the 2,400 GWh produced on the Territory was produced by and supplied to those sites. Approximately 800 GWh (32 per cent of the total energy produced on the Territory) was provided to the public grid.[19]

The largest electricity producer in New Caledonia is La Société Néo-Calédonienne d'Energie (ENERCAL), which also owns the grid concession and most of the thermal and hydropower facilities, covering 98 per cent of the demand of the country (Figure 3).[5]

FIGURE 3

SHP capacities 2013-2016 (MW) in New Caledonia



Sources: *WSHPDR 2013*,[18] Institut de la Statistique et des Etudes Economiques Nouvelle-Calédonie (ISEE)[19]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The electricity supplied to the public grid is currently provided by 20 per cent of the total hydropower production, 36 per cent of the total thermal energy production and the totality of the wind and solar power energy production. The mixed source types (base load, peaking load and intermittent) offer the grid network a steady availability of electricity with rare outages even in remote locations.[5]

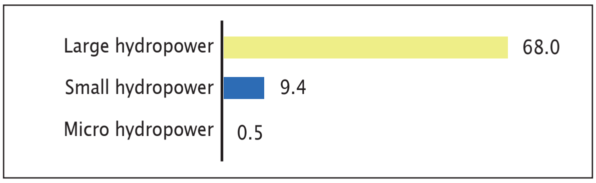
Electricity tariffs for public and industrial uses were established on 31 March 2015. They are valued at 32.24 XPF/kWh (approximately US$0.29/kWh) and 22.01 XPF/kWh (approximately US$0.20/kWh). A monthly fixed fee, which is dependent on the power plan subscribed to, ranges between 3.3 kVA and 19.6 kVA.[6] The Caledonian Government regulates the electricity prices which are updated and published in the Journal Officiel or JONC (Official Board).

Small hydropower sector overview and potential

The definition of SHP in New Caledonia is up to 10 MW. The installed capacity of SHP is 9.9 MW while the potential is estimated to be 100 MW. This indicates that less than 10 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity has increased by approximately 4.3 per cent while estimated potential has increased by approximately 269 per cent (Figure 4).

FIGURE 4

Installed capacity of hydropower in New Caledonia



Source: Institut de la Statistique et des Etudes Economiques Nouvelle-Calédonie (ISEE)[19]

Depending on sources, the hydropower potential in New Caledonia varies between 100 MW and 250 MW.

Although it is not formally stated, installed capacity of hydropower plants in New Caledonia are scaled to the French definition. Plants with installed capacity of 2-10 MW are considered SHP plants. Those with installed capacity between 500 kW and 2 MW are micro hydropower plants and the ones below 500 kW are pico hydropower plants.[7]

There are currently three hydropower plants (two small and one large) connected to the public grid in New Caledonia. Yaté, a large hydropower plant located in South Province, provides 90 per cent of its generation to SLN and 10 per cent to the public grid, with 68 MW installed capacity. Néaoua and Thû SHPs, with 7.2 MW and 2.2 MW respectively, are located in North Province. With the exception of Thû, which is a run-of-river plant, the other two plants are are reservoir dams daily managed as base and peaking load plants to meet the public grid demand, which is dependent on the season.[7] The installed capacities of the micro hydropower plants vary from 20 kW to 147 kW and supply locally their production off the grid (Table 1). The SHP share of total hydropower is 14 per cent.

In 2007, the New Caledonia Department of Mines and Energy (DIMENC) commissioned a study to Enerdata in order to gather information and report on the potential of renewable energy sources for electricity production, available and exploitable to the 2015 horizon. The final survey reported the hydropower potential available in New Caledonia could be about 200 MW, although only 40 MW were likely to be developed by 2015.[9] Of the potential of SHP, which is between 100-250 MW, only 55 MW seems to be viable for development.[8]

The investment costs for SHP projects in New Caledonia vary from one project to another due to several factors common to hydropower project development in remote areas. These include site topography, access availability, grid connection points and procurement of electromechanical equipment.

In 2007, the Direction Générale de l'Énergie et du Climat (DGEC), part of the French Environment and Energy Ministry, estimated the investment cost of low and high head plants to be between US$2,000-2,700/kW and US$1,900-2,400/kW. Including operation

TABLE 1

Micro hydropower in New Caledonia (kW)

Site name	Location	kW
Ouégalé	Pouébo	147
Gohapin	Poya	62
Borendy	Thio	60
Caavatch	Hienghène	56
Pouébo	Pouébo	56
Wadiana	Yate	49
Katricoin	Moindou	30
Kouaré	Thio	27
Wadding	Pouembout	26

Source: ENERCAL[5]

and maintenance costs (about 2-3 per cent), the total production cost would be between US$68-135/MWh. In 2008, the European Commission estimated the total production cost to be between US$66-205/MWh. This is in line with DGEC's figures. The European Commission, however, expects that the range of US$55-160/MWh would be reached by 2030.[9]

In 2013, an independent study performed by the DIMENC estimated the mean production cost for reservoir and run-of-river plants to be US$150/MWh and US$110/MWh. By comparison, existing gas turbine and diesel plants production costs were in the range of US$500-1,000/MWh, or more than five times the hydropower production cost.[15]

The Research and Development Institute (IRD) recommends studying further storage dam options rather than run-of-river plants due to the terrain topography of New Caledonia being relatively steep and not corresponding locally to high rain.[7] Run-of-river schemes need steep slopes and flow availability in order to reduce the waterway length and hence reduce the amount of civil works and related costs.

ENERCAL and the New Caledonian Government have initiated the development of a 40 MW hydropower project located in Ouiné. Construction should start around 2017 and the plant should be commissioned by 2020.[10] Another project (25 MW) is under study in the Mount Panié area but information is very limited to public.[11]

Renewable energy policy

The DIMENC is responsible for the planning and implementation of the country's energy policy. The division promotes projects allowing energy savings or development of new energy sources, such as renewable energy.[12]

A rural electrification fund managed by the Comité Territorial pour la Maîtrise de l'Energie, established in 1983, is the tool for institutional development and rural electrification. It was replaced in December 2002 by a fund with the same purpose, and revised by Resolution No. 33/CP, dated 7 October 2010. Actions from this rural electrification fund help communities in remote areas by providing them with a standard PV installation kit composed of solar panels, batteries, transformers and connections. This fund also supports the development of solar, wind and hydropower projects in remote locations by covering the cost of generators when the total cost of electrification by other sources is higher than those renewable sources.[13]

A multi-year programme for investments, the Programmation Pluriannuelle des Investissements (PPI), for the production of electricity (2008-2015) was proposed to the Congress in 2009. It included the expansion of capacity to at least 15 MW of hydropower, 18 MW of solar, 42 MW of wind and 210 MW of coal. In the end, the country's congress did not approve the programme, because it was assessed that New Caledonia did not have all the tools necessary to ensure the proper implementation of the PPI.[14]

Since then, an independent committee of renewable energy producers in the Territory, Synergy, has drafted a new set of goals and recommendations for the next PPI plan for the period of 2015-2030. It suggests that the following objectives are realistically achievable by the year 2030: The development of 55 MW of hydropower, 6 MW of biomass, 60 MW of wind and 55 MW of solar PV (including 10 MW of residential panels). If those objectives are met, about 290 MW installed capacity could be contributed by renewable sources by 2030. This would increase the electricity production currently generated from renewable energy sources from 15 per cent to 30 per cent. The next PPI plan should be confirmed by the end of 2015.[15]

There is currently a strong trend from the New Caledonian Government and the DIMENC to save energy produced locally by reducing the dependency on fossil fuels, which are likely to have their costs increase by 4 per cent in the coming 15 years. A parallel action plant in line with what is likely to be in the next PPI has been put together to set clean goals. By 2030, it is expected to increase the solar and wind production capacity by 20 per cent and reach autonomous electricity production of the small islands with the new PPI.[15]

Barriers to small hydropower development

The PPI of 2008-2015, which would have included the support for 15 MW of hydropower, was not approved by the New Caledonian Congress in 2009 due to the lack of regulations to support the development of hydropower plants.

The framework for development, installation and regulation of hydropower plants is based on a 1985 deliberation which is not in line with the current institutional organization of the Territory.[16] A list of modifications to update this deliberation has been addressed to the Government by the Conseil Economique, Social and Environnemental, which is awaiting response. Feed-in tariffs are on the list and are still not fixed for hydropower plants in New Caledonia.[17]

Moreover, land acquisition and right of water are not granted when it comes to *terres coutumières* (tribal lands), which are protected by New Caledonian law and cannot be passed to someone, passed over, seized or sold. Those lands represent most of the land in New Caledonia.[17]

The existing interconnections with the public grid and the mining industry's electricity production plants are mostly used punctually, mainly during plant shutdown or peaking periods. The rest of the time, energy comes locally from renewable energy sources producing most of the demand for the public grid. A finer management of the electricity production from mining industry (the main energy consumers and producers) could bring more flexibility in the load/demand on the public grid and towards the development of intermittent renewable sources such as peaking load hydropower stations, solar and wind.[20]

5.2.3 Papua New Guinea

Marcis Galauska, International Center on Small Hydro Power

Key facts

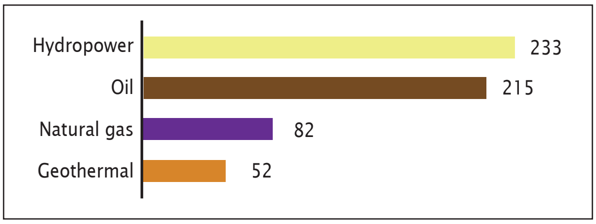
Population	7,463,577[1]
Area	462,800 km[2]
Climate	The climate is tropical, with the coastal plains averaging 28°C, the inland and mountain areas at 26°C, and the higher mountain regions at 23°C. The relative humidity of the area is quite high, ranging at 70-90 per cent.[3]
Topography	The terrain is mostly mountainous, with coastal lowlands and rolling foothills, with the highest point being Mount Wilhelm.[2]
Rain pattern	There is a dry season (June to September) and a rainy season (December to March). Rainfall is heaviest in the highlands, with average annual precipitation varying between 2,000 mm and 5,000 mm, whereas the mainland receives less than 2,000 mm. The island groups to the north and north-east receive an average annual rainfall of 3,000-7,000 mm.[3]
General dissipation of rivers and other water sources	The largest river basins are the Sepik, Fly, Purari and Markham. The Fly, Purari and Kikori Rivers all flow southward into the Gulf of Papua. The Sepik, Markham and Ramu Rivers flow northward into the Pacific. The Fly River and Sepik River are crucial transportation routes. Rising from the Star Mountains, the twisting Fly River is navigable for 805 km. It is 80 km wide at its entry to the Gulf of Papua. The Fly forms a 1,200-km long river system with the Ok Tedi and Strickland Rivers, creating the largest river network in the country. The Sepik River, which is 1,126 km long, has its source in the Victor Emmanuel Mountains. It is wide and navigable throughout its entire length and has no real delta.[4]

Electricity sector overview

The total installed electricity capacity in Papua New Guinea (PNG) was 582 MW in 2010. Hydropower accounted for approximately 40 per cent (233 MW) of this total. Diesel and heavy fuel oil accounted for 37 per cent (215 MW), natural gas 14 per cent (82 MW) and geothermal accounted for 9 per cent (52 MW). All the geothermal capacity was from the Lihir gold mine (Figure 1). Generation and transmission in PNG are only developed for the major urban areas. About 82 per cent of the population has no access to electricity (18 per cent total electrification, 3.7 per cent in rural areas).[14,20] Electricity generation in 2012 was 3,350 GWh.[2]

FIGURE 1

Installed electricity capacity in Papua New Guinea (MW)

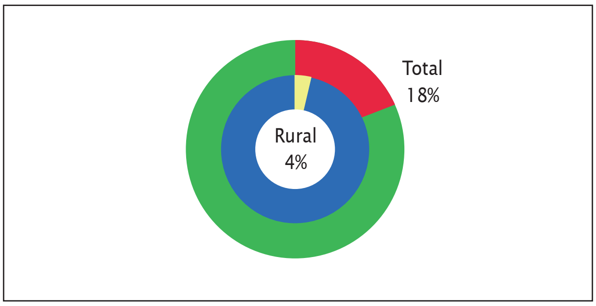


Source: Kuna, I., and Zehner, R.[5]

PNG Power Ltd (PPL) is a fully integrated power authority responsible for generation, transmission, distribution and retailing of electricity throughout PNG, as well as servicing individual electricity consumers. PPL is also undertaking a regulatory role on behalf of the Independent Consumer and Competition Commission (ICCC). These responsibilities include approving licenses for electrical contractors, providing certification for models of electrical equipment and appliances to be sold in the country and providing safety advisory services and checks for major installations. PPL is a state-owned entity.[6]

FIGURE 2

Electrification rate in PNG



Sources: Asian Development Bank,[14] World Bank[20]

There are three major grids in PNG: the Port Moresby System, the Ramu system and the Gazelle Peninsula system. The Port Moresby system serves the National

Capital District, the commercial, industrial and administrative centre of PNG. The Ramu system serves the load centres of Lae, Madang and Gusap in the Momase Region and the Highlands centres of Wabag, Mendi, Mount Hagen, Kundiawa, Goroka, Kainantu and Yonki. The economy of the regions supplied by the Ramu system is based on mining, oil, gas, coffee, tea, timber and industrial productions. The Gazelle Peninsula system serves the townships of Rabaul, Kokopo and Keravat to service Gazelle's economy based on copra, coconut oil, cocoa, timber and fishing.[7]

One of the key tasks for further development is rural electrification. In many cases during the field investigations the loads are identified for potential rural electrification project and this normally fits into one of the following categories:

- Rural infrastructure (government centre, offices, hospitals, missions, schools etc.);
- Rural village communities;
- Commercial enterprises (trade stores, workshops);
- Agriculture-based processing plants (trees, coffee, coconut, timber, rubber).[8]

The National Development Strategic Goals state that in 2030, the energy sector must cover 70 per cent of households and 100 per cent of households must be covered by 2050.[10]

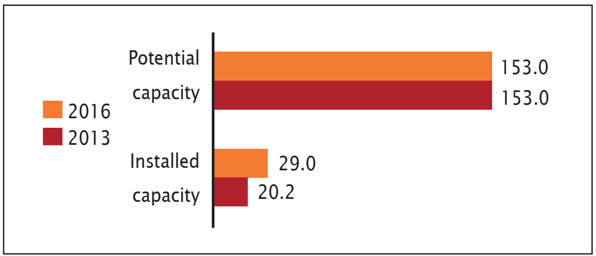
In 2013, the electricity tariffs rose by 5.5 per cent. Electricity tariffs vary between approximately US$0.16-0.33/kWh, depending on type of user (domestic, industrial) and on the amount of consumption.[9]

Small hydropower sector overview and potential

PNG's definition of small hydropower (SHP) is up to 10 MW. The installed capacity of SHP in PNG is 29 MW, while the potential is estimated to be 153 MW. This indicates that approximately 19 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity increased by 50 per cent, with potential capacity remaining unchanged (Figure 3).

FIGURE 3

SHP capacities 2013-2016 (MW) in Papua New Guinea



Sources: *WSHPDR 2013*,[11] IRENA[18]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

While data varies on installed and operational mini and micro hydropower plants, a PIREP report estimated that between 1970-2004, some 200 units were installed, often by NGOs or missionaries. However, detailed documentation is lacking. Nevertheless, the International Renewable Energy Agency (IRENA) estimates the total mini and micro hydropower capacity to be upwards of 3 MW.[18]

The SHP potential has been estimated at approximately 153 MW at more than 79 schemes.[10] A future energy scenario for PNG shows tremendous potential for further commercial energy production from renewable indigenous resources, including hydropower development. In the capacity range of 1-10 MW, at least 6 MW of potential capacity could be realized. Five hundred new micro hydro systems (< 100 kW) with an average capacity of 22 kW could also be realized. The Country Partnership Strategy 2011-2015 for PNG, released by the Asian Development Bank, provides recommendations for rural electrification and technical assistance for micro hydropower projects.[11]

TABLE 1

SHP in Papua New Guinea (MW)

Site name	Status	Capacity (MW)
Warangoi	Functional	10.00
Sirinumu Dam	Upgrade	1.00
PNG Forest Products (2 plants)	Functional	8.00
Ru Creek	Functional	0.80
Lake Hargy	Functional	1.50
Sohun	Functional	0.23
Rouna 1	Upgrade	5.50
Woitape	Functional	0.07
Tari	Functional	0.30
Divune	Tranche 1	3.00*
Ramazon	Tranche 1	3.00*
Ormand	Feasibility	5.00*
Kimadan	Feasibility	5.10*

Sources: ADB,[14] SPREP,[16] World Bank[17]
Note: An asterisk (*) indicates project planned. This list is incomplete. While Divune and Ramazon are listed as Tranche 1, tenders were offered in 2014 for the delivery of materials. Completion data is unavailable at present.[21]

Financial support for SHP projects is available from the Government, especially for rural electrification projects. This is because they are considered as a socio-economic infrastructure development, rather than as an economic investment.[12]

Legislation on small hydropower

The Environment Act No. 64 of 2004 regulates any activities which may cause any impact on the environment. Activities are divided into three levels. Level 2 activities require permits and may require an environmental impact assessment. Under Schedule 1 of the Act, Level 2 activities include operating hydroelectric plants exceeding 2 MW and any damming of a river or stream.[16]

The Independent Consumer and Competition Commission, under Part IIIB, Section 24C of the Electricity Industry Act 2002, has the licensing functions that permits any person, firm or organization that intends to operate in the electricity supply industry. The regulatory authority grants PPL the right of generation and distribution, and also a Third Party Access (TPA) Code and a Grid Code for the Electricity Industry in the country. The TPA will facilitate access to the electricity industry.[19]

Renewable energy policy

There is currently no comprehensive renewable energy development strategy. However, the World Bank will assist the Government of PNG in the development of national policies. The World Bank's Board of Directors have since approved a US$8 million technical assistance project.[12]

There has been a discussion of further development of geothermal energy, as country has a great potential in that. Solar and wind energy are being developed on a small scale by individuals and private organizations. There are plans to develop other renewable energy sources, but in small capacities of approximately 100 kW. Plans include a 100 kW wind/diesel hybrid project for Samarai Island, a 110 kW solar/diesel hybrid for Ambunti and a 100 kW grass biomass project for Maprik.[10]

Barriers to small hydropower development

The barriers to SHP developments are:

- Small population and isolated communities;
- High cost of dams, hydropower stations and transmission and distribution systems;
- Land ownership issues, since more than 90 per cent are privately owned, which restricts development;
- Lack of a development plan, resulting in there being no clear priorities for the electricity sector.

5.2.4 Solomon Islands

John Korinihona, Ministry of Mines, Energy and Rural Electrification

Key facts

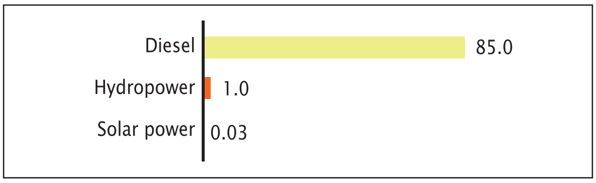
Population	622,469[1]
Area	28,896 km[2]
Climate	The climate is tropical monsoon with few extremes in temperature and weather. The average temperature from January to December ranges between 26°C and 27°C.[3]
Topography	An archipelago of 992 islands, the terrain is mostly rugged mountains with some low coral atolls.1 The highest peak is Mount Makarakomburu, at 2,447 m. The islands include the large high islands of Guadalcanal, Malaita, Santa Isabel, San Cristóbal, Choiseul, New Georgia and the Santa Cruz Group, with many diverse smaller islands. The islands in the archipelago are of two types, either of volcanic origin or coral atolls. The six main islands in the group are volcanic and mountainous, blanketed with dense rainforests. Some volcanoes on the islands are considered active.[3]
Rain pattern	Average annual rainfall is within the range of 3,000-5,000 mm. The southern sides of the larger islands tend to have maximum rainfall from June to September.[2]
General dissipation of rivers and other water sources	Rivers are narrow and impassable except by canoe. Extensive coral reefs and lagoons surround the island coasts. The longest river in the Solomon Islands is the Lungga River, located in Honiara on Guadalcanal. The Tina River, to the east of Honiara, has the most hydropower potential.[3]

Electricity sector overview

In 2014, 85.47 GWh of electricity was generated, predominantly by diesel.[5] More than 90 per cent of electricity was generated by two major power plants, Lungga (71.8 GWh) and Honiara (5.5 GWh). The Ranadi Solar plant generated 0.03 GWh. According to available data, the installed small hydro power plants capacity was approximately 0.258 MW (approximately 1 GWh) (Figure 1).[4,5,7]

FIGURE 1

Electricity generation in Solomon Islands (GWh)



Source: Solomon Islands Electricity Authority[5]

The Solomon Islands are almost entirely dependent on imported refined petroleum fuels for national energy needs for electricity generation, for transport by land, sea and air and for lighting. The installed grid generation capacity is 28 MW and is currently at almost 100 per cent diesel generation. Generation capacity (not including Honiara) is 6.9 MW. In 2009, 11.8 per cent of households in the Solomon Islands were connected to the Solomon Islands Electricity Authority (SIEA) electricity grid. For off-grid access, an additional 0.7 per cent of households had their own generator and 8.7 per cent were supplied by solar, indicating a total household electrification rate of 21.2 per cent.[6]

The Energy Division within the Ministry of Mines, Energy & Rural Electrification is responsible for energy policy, renewable energy development and project implementation. The Electricity Act 1969, detailed in Chapter 128 of the Laws of the Solomon Islands, and associated regulations provide a legal framework for the establishment of a state-owned, vertically integrated utility providing grid supply to urban and provincial centres. In 1982, the Act was amended to align with utility practice at the time and allow SIEA to expand its jurisdiction. Regulations have been promulgated which focus only on the utility functions of SIEA. Part III of the Electricity Act allows SIEA to issue licences to non-utility actors to provide some electricity services. SIEA has developed distributed generation policies. SIEA is an autonomous, government-owned entity. Under the Electricity Act of 1969, it is responsible for the generation, transmission, distribution and sale of electrical energy throughout the Solomon Islands.

In preparation for the proposed 20 MW Tina River hydropower scheme, a framework was defined for negotiation and contracting of an independent power producer who will build, run the scheme and sell power to SIEA under a power purchase agreement. The Government has reached the threshold stage in the project by advancing to transitional stage from project preparatory stage to actual construction (implementation stage). A potential developer has been selected through competitive international tender process for negotiations to develop the 20 MW Tina River hydropower scheme after the completion of feasibility studies in 2014. The independent power producer will negotiate with SIEA on a Power Purchase Agreement. The final Feasibility Study now has the following features:

- 53-metre high roller compacted concrete dam;
- A tunnel of 3.3 m diameter and 3.3 km in length to the power station;
- The overall scheme head is 101 m, net head between intake and tailrace water level;
- A power station of 4 x 5 MW machines providing a potential total output of 20 MW;
- The scheme is expected to produce an average annual energy output of 88 GWh when fully absorbed.

The government has almost completed the process of securing land and has completed environmental and social impact assessment studies. The Government is currently working together with affected communities and tribal landowners on how to cope with social changes anticipated from the project and is assisting the communities to prepare mechanisms to capture the benefits that will flow from the project. It is highly likely that Solomon Islands will never have a single integrated electricity grid network due to its many islands and the deep oceans in between. However, the climate and geography of the country is ideally suited to the development of independent power systems and multi-generator mini-grids.

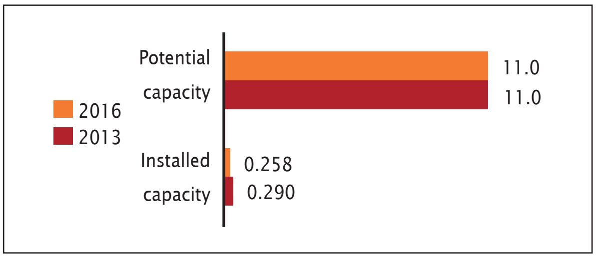
Small hydropower sector overview and potential

The mountainous nature of the majority of the country offers significant micro hydropower potential (Figure 2). There is little access to modern energy sources and the nation is listed as a Least Developed Country under the United Nations system.

The Japan International Cooperation Agency Master Plan 2000 funded a study for power development in the Solomon Islands, including hydropower development. A total of 130 potential hydropower sites were identified, with a total hydro potential of 326 MW, including the Lungga and Komarindi hydropower projects and other previous studies. A summary of the sites identified in the report are listed in Table 1.[9] The majority of the identified potential hydro sites were assessed from desktop or map studies using area, contour and rainfall methods. However, it should be noted that the study seems to be based on theoretical potential, therefore not taking into

FIGURE 2

SHP capacities 2013-2016 (MW) in Solomon Islands



Sources: Ministry of Mines, Energy & Rural Electrification,[6] SIEA,[5] *WSHPDR 2013*[7]
Note: Data do not include mini hydro plants under repair or suspended activity (Table 2).
Note: The comparison is between data from *WSHPDR 2013* and *WSDPHR 2016*.

account technical obstacles such as restricted areas or topographical limitations. The government developed its own database of over 100 sites for possible small hydro development, of which 62 had an estimated overall capacity of 11 MW.[6,7] This report bases the potential capacity of small hydropower (SHP) on study conducted by the government, as seen in Figure 2.

There are 14 hydroelectric systems with capacities below 150 kW, of which five were implemented by an Australian environmental NGO, the Appropriate Technology for Community and Environment (APACE). Six plants are currently operational and are all community-owned. Two government-operated systems are currently 'suspended', primarily due to technical issues. The oldest remaining micro-hydropower system, at the Atoifi Adventist Hospital, has experienced frequent technical problems and is currently undergoing repairs. The success of the majority of currently operating micro-hydroelectric systems in Solomon Islands is significantly due to the efforts by APACE, and its work in researching procedures and technologies to allow access to the technology by the rural people of Solomon Islands.[8]

TABLE 1

Total potential of hydropower sites

Islands	Number of sites	Micro (kW)	Mini (kW)	Small (kW)	Total (kW)
Guadalcanal	49	—	1,210	236,100	237,310
Malaita	23	90	2,700	28,000	30,790
Santa Isabel	6	—	610	4,100	4,710
New Georgia	23	320	4,840	—	5,160
San Cristobal	12	20	371	25,500	25,891
Choiseul	15	140	2,030	20,030	22,200
Santa Cruz	2	50	260	—	310
Total	**130**	**620**	**12,021**	**313,730**	**326,371**

Source: SIEA[5] (based on JICA's 2000 study, 'Master plan study of power development in Solomon Islands: Final report' (pp. 5-18).
Note: Overall theoretical potential; it is assumed the technical and economically feasible potential is roughly the same as those in *WSHPDR 2013*.

TABLE 2

Micro-hydropower systems in Solomon Islands

Year of commissioning	Location	Ownership	Turbine	Installed capacity (kW)	Status
1952 [a]	Fauabu[b]	Melanesian Mission	Turgo - Gilkes	10	Not operational
1973 [a]	Atoifi	Adventist Hospital	Pelton - Gilkes	30	Ceased operation around 1980
1986	Atoifi	Adventist Hospital	Pelton - Hydro Systems	36	Under repair
1983 [a]	Iriri	Community	Pelton - Apace	3	Ceased operation 1997
1984	Malu'u	SIEA (government)	Crossflow - SKAT	35	Suspended (land and technical issues)
1993 [a]	Vavanga	Community	Crossflow - Apace	2	Ceased operation in 2001
2004	Vavanga	Community	Pelton - Pelena	8	Operating
1995	Manawai	Community)	Pelton - Canyon	16	Operating
1996	Buala (Jejevo)	SIEA (government)	Pelton - Andritz	150	Operating
1997	Ghatere	Community	Crossflow	8	Incomplete and damaged
1999	Bulelavata	Community	Crossflow - Pelena	24	Operating
2003	Raea'o	Community	Pelton - Pelena	30	Operating
2004	Nariao'a	Community	Pelton - Pelena	30	Operating
2010	Masupa	Community	Pelton - Pelena	40	Under repair

Source: Solomon Islands Electricity Authority[5]
Notes: a. decommissioned systems; b. unconfirmed
Note: Data as of September 2015.

In 1996, the German Agency for Technical Cooperation (GTZ) supported the study of three mini-hydropower schemes in the Solomon Islands. The GTZ supported the construction of the Jejevo (Buala) hydropower scheme in Santa Isabel Province, but did not fund the construction of the Huro and Rualae Mini-Hydropower Schemes in Makira and Malaita Provinces respectively. Consultants have recently been engaged to re-evaluate these projects.

With support from the World Bank, AusAID and other agencies, the Solomon Islands Sustainable Energy Project (SISEP) began operations in 2009. SISEP aims to improve the operational efficiency, system reliability and financial sustainability of SIEA through improved financial and operational management, reduction of losses, and increased revenue collection.[4] The Energy Division, working with the Water Resources Division, plans to install five water-gauging systems and intends to expand this programme to other sites in the future.

From 2010-2012, the Asian Development Bank conducted pre-feasibility studies at selected provincial and industrial centres around the country to develop hydropower. The sites include:

- Vila River on Kolombangara island for Ringgi township (1,210 kW);
- Mase River for Noro industrial centre on New Georgia island (2,000 kW);
- Sorave Falls for proposed Choiseul Bay township and the Choiseul provincial government centre located on Taro island (150-730 kW);
- Huro River for Kira Kira township on Makira island. Studies were also conducted on this river by GTZ in 1996 (120 kW);
- Luembalele River for Lata township on Santa Cruz island (190 kW);
- Fiu River for Auki township on Malaita island (750 kW).

Out of the above sites, detailed feasibility studies were conducted on the Fiu River, Huro River and Luembalele River in 2013.

The Government of the Solomon Islands has committed to develop the Fiu River hydropower scheme (750 kW) and has finalized financing agreements with the Asian Development Bank in June 2014 to develop the scheme.[4] The Fiu River hydro scheme will have the following features:

- A run-of-river scheme comprising an intake structure, 1.5 km headrace canal, forebay and 250-m steel penstock and a powerhouse.
- Will include approximately 10 km of 11 kV transmission line from the hydro powerhouse to the 11 kV bus-bar at the existing SIEA diesel power station at Auki town and step-down transformers. The grid will be extended to an estimated additional 250 households. The project will also include a 3.5 km new access road to the hydro site.
- Two 250 kW units will be installed initially. However, the waterway and powerhouse will be designed for

three 250 kW units to cater for the long-term load demand. The current maximum demand in Auki is 360 kW and the maximum demand is forecast to increase to 410 kW by 2018.

- The project will reduce diesel imports into Malaita Province for power generation by 672,000 litres by June 2018 (after commissioning) relative to June 2014 baseline.[4]

Renewable energy policy

The Ministry of Mines, Energy and Rural Electrification is currently responsible for energy sector policy formulation, legal and regulatory development and institutional strengthening. The Solomon Islands National Energy Policy was endorsed in 2007. The National Energy Policy framework of 2007 has been reviewed and the Ministry of Mines, Energy & Rural Electrification hopes to finalize the updated policy framework for endorsement by Cabinet by the end of 2015.

Although there is no renewable energy policy in the country, there is a Renewable Energy Investment Plan (SREP) formulated by the government in 2013-2014, which was submitted to the SREP sub-committee of the Climate Investment Fund at its meeting held in Montego Bay, Jamaica in June 2014. Subsequently, the SREP sub-committee approved funding for scale-up of renewable energy projects in Solomon Islands.

Due to the archipelagic nature of the country and its widespread population throughout the islands with varying load centres, the SREP funds will fund five components of the scaling-up renewable energy programme in the country to achieve the target of increasing electricity access from the current 16 per cent to 25 per cent by 2020 and to increase the renewable energy share in the total energy supply from less than 1 per cent to 50 per cent by 2020.

One of the five components is to develop 60 new mini-grids supplied by micro hydro, coconut based biofuel and solar photovoltaic power. US$5.4 million is allocated for this particular component from the SREP funds, which should leverage a further US$7.5 million from the government or the SIEA, donors, the World Bank and the private sector with a total of up to US$12.9 million. With support from the World Bank, the status of the project is currently in its planning stage.

Legislation that impacts energy includes:

- The Electricity Act of 1969, which created SIEA and gave it exclusive rights for power generation in Honiara and provincial centres. Exclusions were later added which allowed private generation of less than 50 kW capacity for certain purposes without the need for an SIEA licence. This allowed rural villages to generate their own electricity without a licence as long as their generation capacity remained below 50 kW.
- Fuel storage and handling are covered by the Petroleum Act. The provisions of the Petroleum Act dealing with the annual relicensing of fuel storage facilities are being enforced. There is no legislation for regulation of biofuels.
- The Consumer Protection and Price Control Act (1995) establishes price control rules but, of the sixteen products specifically mentioned in the Act, only petroleum products and LPGs are currently systematically price controlled.
- The Environmental Act (1998*)* commenced operation in September 2003 and its relevant regulations were gazetted in 2008. Under the Act, there are formal requirements for environmental impact assessments, and requirements for energy sector investments such as power stations or oil storage.

The Provincial Government Act of 1981 allows provincial governments to provide electrical services within their jurisdiction. Private generators such as rural villages can generate their own electricity without a licence as long as their generation capacity remains below 50 kW (due to later exclusions to the Electricity Act 1969).

The River Waters Act of 1981 is intended to prevent upstream water uses to adversely impact on downstream populations, which impacts hydropower development. The Environmental Act of 1998 includes environmental impact assessment requirements that could affect some future energy sector investments. The Land Tenure Legislation attempts to sort out some of the many issues surrounding the use of land in the Solomon Islands. About 87 per cent of land rights are based on Customary Land terms, the traditional approach to land transfer and use, and the rest is Alienated Land, which was procured and given freehold title during the colonial era.[4]

Barriers to small hydropower development

There are a number of barriers identified to the expansion of renewable energy in the Solomon Islands which includes hydropower development. These are:

- Lack of standardized and streamlined approaches for land acquisition for distribution extensions and mini-grids;
- Outdated regulatory framework which requires revision;
- Requirement to improve system planning and project management capacity within SIEA;
- Need to strengthen MMERE capacity to develop appropriate policies and regulations;
- High upfront capital costs for most renewable energy projects.

The government will use the SREP financing to bring down the cost of new renewable energy projects (in this case, hydropower) at larger scale than under current planning scenarios. The SREP-supported projects will facilitate the reform agenda via a learning-by-doing approach.

5.2.5 Vanuatu

John Christopher Simelum, Ministry of Climate Change Adaptation and Disaster Management

Key facts

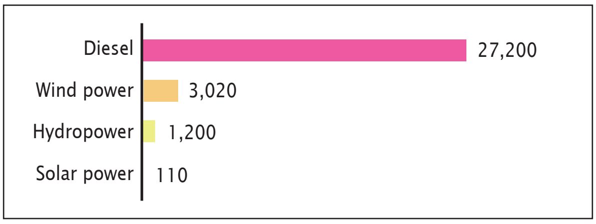
Population	280,201[1]
Area	12,190 km[2]
Climate	Vanuatu has a tropical maritime climate with characteristic uniform temperature, high humidity and variable rainfall. Winds are generally light except during a tropical storm. The climate of Vanuatu can be defined by two main seasons: the cold (dry) season (May to October) and the hot (wet/cyclone) season (November to April). The warmest month is February and the coolest is August. In the coastal areas, daily temperatures average 26°C in the hot season with an average maximum of 30°C and an average minimum of 24°C. Extreme night-time minimum temperatures in some coastal areas may reach 13°C.[3]
Topography	It has more than 80 tropical islands, composed of coral reefs and volcanic deposits. The highest point is Mount Tabuemasana, at 1,897 m.[3]
Rain pattern	During the wet season, rainfall is particularly high on the windward side (south-east) of the bigger islands and scarce during the dry season especially on the leeward sides (north-west). Rainfall is variable on the smaller islands, depending on their location and size. Rainfall on the island of Efate shows this particular pattern. On the windward side, annual rainfall is measured from 2,400 mm to 3,000 mm and is almost half that amount on the leeward side.[3]
General dissipation of rivers and other water sources	Vanuatu has relatively few rivers, considering the tropical location of the islands. Small island areas and porous volcanic terrain reduce the potential for river formation. However, many small streams do drain the mountains, including the Jourdain, Sarakana and Wamb Rivers. Though less abundant on Efate, most of the larger islands have significant river systems and potential for viable hydropower. The Sarakata River flows adjacent to the main Santo town of Lugainville into the ocean. It experiences periodic flooding, has encroaching urban sprawl, hydroelectric power generation, and agriculture development.[2]

Electricity sector overview

The installed electricity capacity at the end of 2014 was 32 MW. Generation was mostly based on imported diesel (86 per cent), although 4.33 MW was from renewable energy sources (14 per cent) (Figure 1).[5] Demand for electricity is steadily increasing and is predicted to continue to rise through 2030 (Figure 2). Electricity generation accounts for 38 per cent of the demand. Generation in 2014 was 80 GWh.[4] Over 80 per cent of all electricity generated in Vanuatu is from diesel fuel. Diesel is the largest volume imported (33 million litres) as it is used in electricity generation (18 million litres, including use for outer islands generation).[4]

FIGURE 1

Installed electricity capacity in Vanuatu (kW)

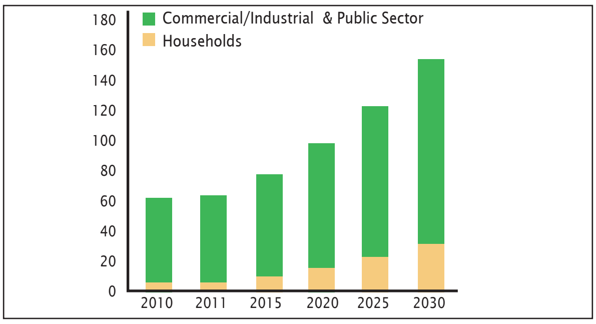


Source: The Utilities Regulatory Authority[5]

The Vanuatu Government considers development of the electricity sector as a priority. The Vanuatu National Energy Roadmap 2013 (NERM), which was developed with support from the World Bank, lays the foundation for future energy sector policy and investment in Vanuatu.[4] There are four electricity concessions in four major islands of Vanuatu, Efate, Santo, Malekula and Tanna. These are operated by private service providers Vanuatu Utilities Infrastructure (VUI, Pernix Group) Ltd and Unelco Ltd (Suez).

FIGURE 2

Forecast demand for electricity in Vanuatu, 2011-2030 (GWh)

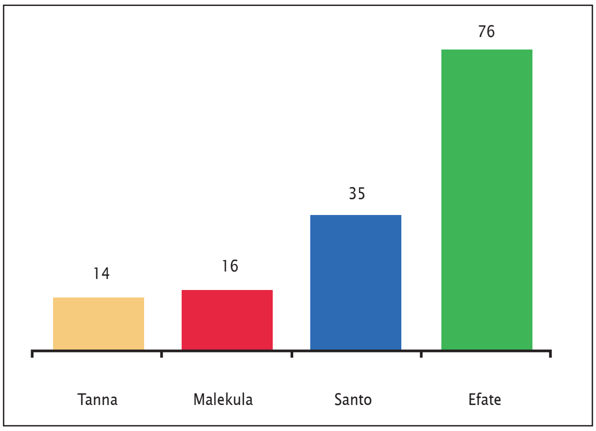


Source: The Vanuatu National Energy Road Map, Government of Vanuatu[4]

Due to the formations of islands and remote rural communities, the Vanuatu overall electrification rate is low (27 per cent). Overwhelmingly, those without access live in rural areas and outside of Efate Island. Even on these largest four islands (of the 80+ islands of Vanuatu), the share of those without access remains high: Efate (24 per cent), Santo (65 per cent), Tanna (86 per cent) and Malekula (84 per cent) (Figure 3).

FIGURE 3

Electricity access in Vanuatu

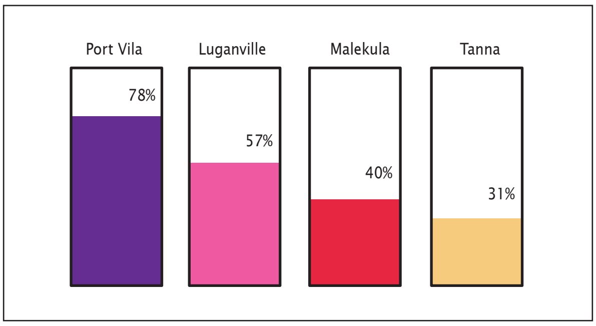


Source: Department of Energy[4]

Connection rates in concession areas can be seen in Figure 4. Initial estimates suggest that additional funds of US$20 million are required to ensure that the Government's target to electrify 90 per cent of the concession areas is achieved by 2020 and 100 per cent of households are electrified by 2030.[4]

FIGURE 4

Connection rates in concession areas



Source: Department of Energy[4]
Note: Includes households using electricity from the main grid by shared connections.

The Department of Energy is planning to establish standalone micro grids (through the Vanuatu Rural Electrification Project Phase 2) and possibly introduce hybrid of solar and small hydropower (SHP) projects to be developed in remote areas due to insufficient electricity grid connections. Electricity and transmission lines connecting all the islands are not feasible, resulting in great variations in electricity prices.

However, the situation has steadily improved. The development of grid extensions and household connections at the four major electricity concessions are subsidized and co-financed with the support of development partners such as the World Bank, Asian Development Bank, Climate Investment Fund and other incentives.

The electricity market was privatized since gaining independence in July 1980. In 2007, the Utilities Regulatory Authority Act was adopted, which authorized the formation of the Utilities Regulatory Authority (established in 2009). Under the direction of the Chief Executive Office, the URA is responsible for regulating tariffs on water and electricity services in Vanuatu.[4]

In Vanuatu there is a cross-subsidy mechanism designed to support access to electricity services for poorer households. Consumers under the Small Domestic category are paying lower subsidized rates for electricity up to 60 kWh. Therefore, those in the Domestic Consumers threshold are paying a higher price per kWh. The cross-subsidization is more evident for UNELCO consumers. Vanuatu, compared to other parts in the Pacific region, has a very high cost of electricity (US$0.50/kWh).[5,6]

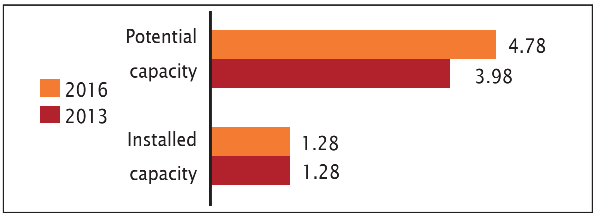
Expensive electricity tariffs limit its usage, making the average annual consumption per household in Vanuatu very low (compared to some other Pacific island nations). For example, a typical low-income household in Vanuatu would use approximately 30 kWh per month to run several lights, listen to radio, and charge cell phones. Additionally, high tariffs add to the high cost of doing business in Vanuatu and undermine economic competitiveness.[4]

Small hydropower sector overview and potential

The installed capacity of SHP in Vanuatu is 1.28 MW, while the potential is estimated to be 3.98 MW indicating that 32 per cent has been developed. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, there has been no change in installed capacity. Potential has increased as indicated by plans for future development (Figure 5).

FIGURE 5

SHP capacities 2013-2016 in Vanuatu (MW)



Sources: The Utilities Regulatory Authority,[5] Vanuatu Energy Road Map,[4] *WSHPDR 2013*[7]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

On the island of Santo, about 70-80 per cent of the generation comes from the Sarakata Hydro Plant (1.2 MW), which has been operational since 1997. There are several pico hydro projects being developed for individual consumption. On the island of Maweo, a pilot hydro project of 70 kW is currently being developed for three communities (200 households). Two other hydro plants are subject to further feasibility studies on design and appropriate resource availability. These two power projects could stimulate economic development in Malekula and Espiritu Santo by improving affordability in these two concession areas:[4]

- In Malekula, the Brenwe Hydro Power Project (< 1.2 MW) will increase capacity to meet demand until at least 2041. The levelized cost of electricity generated from the hydro plant is estimated to be 29.5 VUV/kWh (approximately US$0.31/kWh), which is below the levelized cost of diesel generated electricity of VUV 33.3 (approximately US$0.37). The hydro plant is estimated to cost US$4.5 million and will displace most of the diesel generation in the concession area. The Project will be co-financed through grants and loans from the Scaling up of Renewable Energy Program (SREP-2014 Vanuatu) and the Asian Development Bank respectively.[4]
- In South Espiritu Santo, the Wambu River Mini Hydro Project will provide about 2.2 MW generating capacity for the Luganville concession area. The Wampu project has an estimated levelized cost of 32.3 VUV/kWh (approximately US$0.34/kWh) and this is expected to reduce tariffs when it begins generating, providing strong support for large industrial investments in the Luganville area. Construction is expected take place between 2019-2021, costing about VUV 1.4 billion (approximately US$16 million).[4]

In addition to the above, VUI has also indicated that there is potential for upsizing the existing Sarakata plant with additional 500-600 kW capacity, that could contribute to increasing hydro capacity of Luganville. Unelco is undertaking pre-feasibility studies for hydro power on rivers such as La Colle and Teouma on the island of Efate, possibly contributing to another 5 GWh within five years. A prior pre-feasibility study on Teouma River dated 1992 will be updated. The VUI and Unelco hydro projects are subject to further feasibility studies and have therefore not been included in the investment prospectus.[4]

Renewable energy policy

As a tropical country, Vanuatu has potential in renewable energy resources, particularly solar, hydro, biomass, geothermal and wind, but only a small fraction of this potential is currently used. The power sector has been characterized by significant challenges in terms of access. The target for Renewable Energy (in generation) is 40 per cent by 2015 and 65 per cent towards 2020. The estimated share of renewable energy generation is shown in Figure 6. The Vanuatu Rural Electrification Project (VREP) currently in implementation stage will establish Plug and Play Solar Home Systems for rural households, aid posts and community halls. The next phase of the project will be to develop micro-grids feasible for larger communities that ideally are close to public institutions. The Government of Vanuatu is embarking on appropriate legislation in the energy sector to promote new projects to modernize Vanuatu's power industry and enable a greener energy future.

The NERM identifies five priority areas and targets for Vanuatu's energy sector, including:

- Access to secure, reliable and affordable electricity for all citizens by 2030;
- Petroleum supply: reliable, secure and affordable petroleum supply throughout Vanuatu;
- Affordability: lower cost energy services in Vanuatu;
- Energy security: an energy secure Vanuatu at all times;
- Climate change: mitigating climate change through renewable energy and energy efficiency.

Major plans for renewable energy projects include:

- 8 MW North Efate Geothermal Energy (Status: Conducting slim drills to identify prospect);
- Bio-diesel Projects on government provincial centres, Ambae, Vanua Lava. (Status: Installation stage);
- Brenwe Hydro Project (Status: Negotiation of funding);
- The UAE funded Grid Connect Solar Project for two government buildings, the parliament complex and the Ministry of Climate Change complex (Status: Installation);
- European Union, funded with Unelco and Government Solar Farm, 1.5 MW grid connected (Status: Design and tendering of works).

Barriers to small hydropower development

Major barriers on renewable energy and hydro developments:

- High cost of feasibility. To properly collect data and conduct a full-scale feasibility and technical aspects, the government relies on development partner support.
- Technical Support. The Department of Energy lacks technical expertise of hydro studies. Training and capacity development in operation and management must be developed as an essential for hydro development.
- Lack of regulation of technical specifications in particular for the power grid connection.
- Challenge of transporting renewable energy generated electricity through the transmission system to the communities and public institution is very high.

5.2.6 Federated States of Micronesia

Rupeni Mario, Secretariat of the Pacific Community

Key facts

Population	104,044[1]
Area	3.37 km^2 geographical area, 702 km2 land mass and 607 islands, 74 inhabited
Climate	The climate is tropical, with quite even and warm temperatures throughout the year, averaging 26°C to 32°C.[2]
Topography	The terrain consists of large, mountainous islands of volcanic origin and coral atolls. Kosrae is largely mountainous, with two peaks, Fenkol (634 m) and Matanti (583 m). Pohnpei contains a large volcanic island, with the highest elevation at Mount Totolom (791 m). Chuuk contains 14 islands that are mountainous and of volcanic origin. Yap contains four large high islands, with the peak elevation that of Mount Tabiwol (178 m). The outer islands of all states are mostly coral atolls.[2]
Rain pattern	Precipitation is generally plentiful, with heavy year-round rainfall. Pohnpei is one of the wettest places on earth, with up to 8,400 mm of rain per year.[2]
General dissipation of rivers and other water sources	The steepest and wettest of the islands, such as Pohnpei and Kosrae, feature tumbling rivers, often broken with waterfalls.[2]

Electricity sector overview

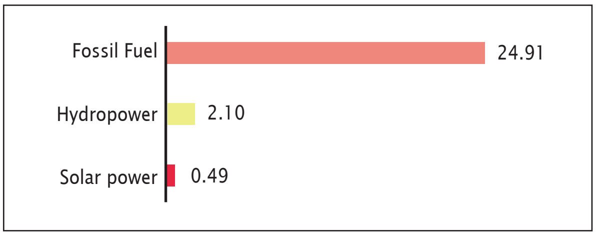
The Federated States of Micronesia (FSM) has four states: Kosrae, Pohnpei, Chuuk and Yap. The electricity sector is made up of state-owned corporations. These include the Kosrae Utilities Authority (KUA), the Pohnpei Utilities Corporation (PUC), the Chuuk Public Utility Corporation (CPUC) and the Yap State Public Service Corporation (YSPSC) governed by a Board with members appointed by the respective state governments. These corporations were established under State Codes (Kosrae State Code Title 7, Pohnpei State Code Title 34, Chuuk State Code Title 30 and the Yap State Code 1987, Title 14). The four corporations of KUA, PUC, CPUC and YSPSC are also tasked with responsibilities in the water sector.

The FSM, like most of the Pacific Island countries, generates its primary electricity from diesel. Fuel to the four states is supplied by the FSM Petroleum Corporation (FSMPC), a public corporation established under the FSMPC Act of 2007. The total installed diesel capacity in 2014 was 25 MW which consisted of 2 MW in Kosrae, 10 MW in Pohnpei, 6 MW in Chuuk and 8 MW in Yap (Table 1). There are renewable energy projects mainly funded by development partners, which represented 22.6 per cent of total installed capacity in 2014.[4]

The electricity access across the FSM averages 55 per cent. This is distributed over the four states with access on Kosrae at 98 per cent, Pohnpei at 87 per cent, Chuuk at 27 per cent and Yap at 67 per cent.[8]

FIGURE 1

Installed electricity capacity in the FSM (MW)



Source: World Bank[8]

The aging electricity generation infrastructure has been undergoing upgrading to improve efficiency and minimize technical losses. An analysis by the Pacific Power Association in 2010, which was updated in 2013, has identified a series of technical and non-technical losses including remedial measures and cost-benefit analysis. These have been implemented when funding is available.

Electricity tariffs across the four states are determined by the respective utilities, which average to US$0.45/kWh. The tariffs for the outer islands are much higher with some outer islands having to pay over US$1.00 per unit.[6]

TABLE 1

Installed electricity capacity in Micronesia

Islands	Plants	Installed / available capacity (kW)
Chuuk	Diesel generators 2 x 1,300 / 2 x 1,800	6,200 / 5,600
Kosrae	Diesel generators 6 x (560 to 1,650 kW) Solar (~ 450 kW)	(N/A) / 2,060
Pohnpei	Diesel generators SHP (725 kW available)	10,710 / 6,500
Yap	Diesel generators	8,549 / 7,054

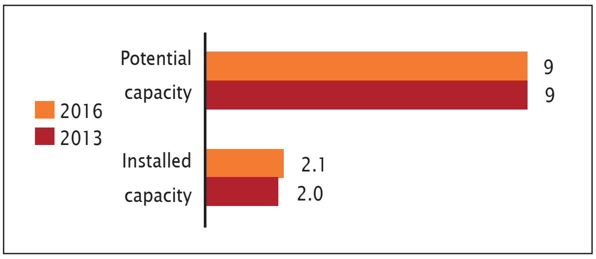
Source: World Bank[8]

Small hydropower overview and potential

The small hydropower (SHP) installed capacity of the FSM is 2.1 MW. The SHP potential is 9 MW. The currently-operating 725 kW (rehabilitated availability, original installed capacity 2.1 MW) run-of-river hydropower plant at Nanpil, Pohnpei, is classified as a mini hydro, in terms of general classification for hydropower plants based on plant size and magnitude of socio-economic concerns. In the FSM context, this provides about 11 per cent of the installed capacity in Pohnpei.[3]

FIGURE 2

SHP capacities 2013-2016 in the FSM (MW)



Sources: *WSHPDR 2013*,[5] Energy Transition Initiative,[7] Secretariat of the Pacific Community[6]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The Nanpil hydropower plant was recently rehabilitated in 2014 by the European Union, the Secretariat of the Pacific Community and the FSM Government partnership, through the North Pacific ACP Renewable Energy and Energy Efficiency Project.[7]

The hydropower potential in the FSM is limited to the states of Kosrae and Pohnpei. Previous studies have identified a potential of at least 35 kW and 5 MW respectively.[7]

Renewable energy policy

The FSM adopted its first national energy policy on 3 October 2011 by the C.R. No. 17-62 of the 17th Congress of the FSM. The policy highlights a renewable energy target of 30 per cent of total energy production by 2020. At the state level, there are four action plans, published as Volume II with the FSM National Energy Policy, that has prioritized objectives and activities.[4]

Barriers to small hydropower development

In a small island context, the FSM is rich with renewable energy resources, particularly solar, hydro, biomass and wind. However, only a small fraction of this potential is currently used. The power sector has been characterized by aging infrastructure compounded with capacity constraints, maintenance challenges and limited incentives for the development of renewable energy.

The current assistance through development partners such as the World Bank, Asian Development Bank, the European Union and the Secretariat of the Pacific Community has provided pathways for further development opportunities in renewable energy.[3]

There are, however, challenges that still exist. These include:

- Limited site-specific hydrology data;
- No dedicated funding for hydro power development;
- Limited capacity to plan and conduct renewable energy resource assessments;
- No dedicated water supply ponds thus current potential ponds for hydro power are also being used as reservoirs for the water supply.

5.2.7 French Polynesia

Thierry Trouillet

Key facts

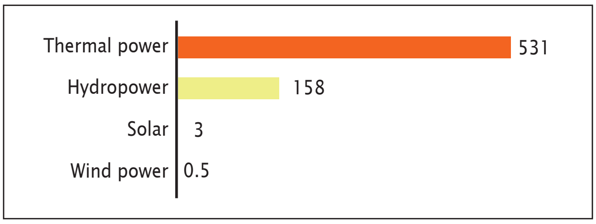
Population	271,800[1]
Area	2,504 km[2]
Climate	The climate is tropical and humid with two seasons: a warm and humid season (November to April) and a drier season (May to October). The average temperature ranges between 21°C and 31°C with little seasonal variation.[2]
Topography	The islands have high volcanic peaks and low-lying coral atolls. There are 118 islands in five archipelagos that make up 2,504 km2 of emerged land. The total territory, including territorial seas is roughly 2.5 million km2, with the Exclusive Economic Zone (EEZ) encompassing 5.5 million km^2.[3]
Rain pattern	The wet season occurs from November-April. January is the wettest month of the year, with 340 mm of rainfall in Papeet□. August is the driest month, with only 48 mm of rainfall.[2]
General dissipation of rivers and other water sources	Numerous rivers, including the Papenoo, make up the torrential regime. The rivers descend from the mountains by waterfalls and in successive steps. None are navigable.[2]

Electricity sector overview

French Polynesia consists of 118 islands grouped in five archipelagos. Overall electricity capacity in 2014 was 227 MW, with 50 MW from renewable source (RE). Electricity generation was 692 GWh, with 161.5 from RE (Figure 1).[4] The majority (60 per cent) of the population live in Tahiti and consume 77 per cent of the electricity. Production and consumption of electricity vary per island, depending on remoteness, population, and installation of plants. The Electricité de Tahiti (EDT), along with its subsidiary Marama Nui, is the largest electric utility. EDT owns 14 power stations with 217 MW capacity. Other public utilities and independent power producers (IPPs) supply the remainder, often for the more remote islands.[6]

FIGURE 1

Electricity generation in French Polynesia (GWh)



Source: de Figueiredo[4]

In Tahiti, fossil fuels contribute the most to the energy mix at 64 per cent, while hydropower represents 31 per cent. The balance consists of other renewable sources such as solar PV.[5] Other islands utilize fossil fuels for 100 per cent of energy generation. This is costly for the island nation, as 90 per cent of fossil fuels are imported. The islands have independent grids. For example, Tahaa has an installed capacity of 1 MW, which is sufficient to meet demand (roughly 1 per cent of Tahiti). While fossil fuels remain the dominant source for the energy mix, hydropower does represent significant percentages in both Tahiti and the Marquesas, while the Tuatmotus and Gambier Islands have the highest number of solar PV units.[5]

The potential capacity for the energy sector is an additional 140 MW, with 36 per cent from renewable energy (RE), and potential generating capacity is an additional 662 GWh, with 26 per cent from RE.[4]

The electrification rate in French Polynesia is 98 per cent, covering nearly all of the most remote locations. This is contributed to not only by EDT and IPPs, but also due to projects such as Programme PHOTOM, which saw the installation of 1,400 autonomous solar PV units on individual houses with an estimated total capacity of 1.8 MW spanning 29 islands.[5]

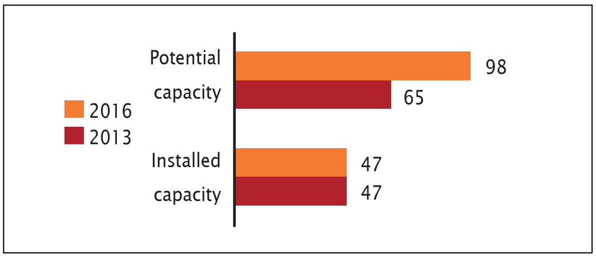
Tariffs on electricity vary depending on type and amount of consumption (e.g. residential or commercial, 200-280 kWh or 281-400 kWh). However, with one of the world's highest base prices and with tariffs the consumers must bear, French Polynesia has some of the most expensive electricity in the world. In 2015, tariffs ranged US$0.25-US$0.51/kWh for residential use. The high costs are in part to subsidize the cost of electricity in remote locations, which would be even higher without this system.[4]

Small hydropower sector overview and potential

French Polynesia considers plants to be small hydropower (SHP) plants when they have an installed capacity of up to 10 MW. Between the *World Small Hydropower Development Report* (*WSHPDR*) *2013* and *WSHPDR 2016*, installed capacity remained unchanged while potential capacity increased by more than 30 MW, mainly due to feasibility studies (Figure 2). This indicates that installed SHP capacity is roughly 48 per cent of potential.

FIGURE 2

SHP capacities 2013-2016 in French Polynesia (MW)



Sources: EDT,[6] *WSHPDR 2013*[7]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

The largest hydropower source is the Papenoo River, which is home to the Papenoo Hydropower Installation. The system comprises five dams and three power stations, which utilize 4-MW Pelton turbines. The entire installation provides up to 20 per cent of the electricity on Tahiti (Table 1).[6]

TABLE 1

Installed SHP in French Polynesia

Location	Site	Installed capacity (MW)
Tahiti	Vaihiria 1,2,3	4.6
	Vaite 1,2	2.3
	Titaaviri 1,2	4.1
	Faatutia (Hitia'a) 1,2,3,4,5	7.5
	Papenoo 1	16.0*
	Papenoo 2	4.0
	Papenoo 3	8.0
Marquesas Islands	Nuku Hiva and Hiva Oa Islands	1.2
Total		**47.7**

Source: EDT[8]
Note: An asterisk (*) denotes larger than 10 MW capacity.

TABLE 2

Potential SHP in French Polynesia

Site	Expected capacity (MW)
Tuauru	4.0
Ahonu	0.5
Papenoo	4.0
Onohea	3.0
Vitaara	6.0
Papeiha	13.8*
Taharuu	15.0 *
Mateoro	4.0
Total	**50.3**

Source: EDT[6]
Note: An asterisk (*) denotes larger than 10 MW capacity.

SHP potential is currently under study, including capacity expansion potentials of updating existing ageing plants. With regard to existing plans in SHP development, the hydropower project at Papeiha (13.8 MW) has already been validated by the Government and the preliminary studies are in progress.

Financing for hydropower studies and construction of installations has come mainly from three sources: the Government of French Polynesia, the Agence Française de Développement and the European Investment Bank.

Renewable energy policy

The Government of French Polynesia seeks to achieve a total of 50 per cent of electricity consumption from RE by 2020 and 100 per cent by 2030. To achieve this goal, it is implementing several programmes, including reducing the impact of electricity prices to make them affordable for the end user. In 2011, tariffs for RE were fixed. This was done in part to ease the burden on consumers but also to incentivize the installation of the systems. Hydropower received a fixed tariff of US$0.11/kWh, while wind was set at US$0.13/kWh. Solar energy was set at US$0.14/kWh in Tahiti (US$0.22/kWh elsewhere).[5]

RE must contribute to a stable and reliable distribution network. While the network has been stable since 2006, there are still outages with an average loss of service at below two hours. The Government seeks to increase stability through the utilization of renewable energy.

The type of RE produced must also match the diverse topography of the islands. The Government of French Polynesia has selected several sectors to promote to achieve the 50 per cent by 2020 goal. As such, the authorities are developing the hydropower, solar, and hybrid forms of electricity generation sectors.

Regarding the development of hydroelectric power production, five valleys have been selected for feasibility studies in mountainous regions. The Papeiha valley project has already been validated. This project is in an isolated location and is designed to respect the environment. This, unfortunately, makes it more expensive

Solar energy will take an increasingly larger role in French Polynesia. French Polynesia benefits from vast solar resources, with the only limiting factor being the size of the distribution network. To undertake more projects, the islands will need alternative, often expensive, energy storage solutions.

The third sector consists of hybrid solar and diesel power generation, used in the outer island atolls. Currently, six of these hybrid systems are in operation, and three more will become operational in 2016. These systems provide a more reliable source of electricity. Cost is a restriction, as these systems produce power using diesel which increases watt peak cost.

Other alternative systems have begun to take shape in the islands, in particular using deep sea water as a cooling mechanism for the air conditioning needs of hotels and hospitals.[5]

Barriers to small hydropower development

Considering the size of the islands and their population, the main difficulties faced by the Government with regard to the implementation of hydroelectric projects are environmental concerns. The valleys with hydro potential often contain protected species and archaeological sites. Topographical limitations on smaller islands also hinders SHP development, although solar and wind can provide the required capacity instead.

5.2.8 Samoa

Sione Foliaki, Ministry of Finance

Key facts

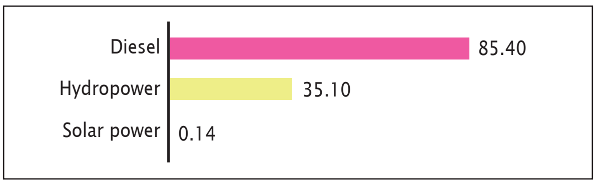
Population	191,845[1]
Area	2,900 km^2
Climate	The climate of Samoa is tropical with abundant rainfall. Humidity averages 80 per cent. The average daily temperature ranges from 22°C to 30°C, with very little seasonal variation. There are two major distinguishable seasons: the wet season extends from November to April and the dry season from May to October. During the dry season, the climate is pleasant because of fresh trade winds.[2]
Topography	Samoa consists of two main islands, Savaii and Upolu, as well as several smaller islands and uninhabited islets. Most have narrow coastal plains with volcanic, rocky and rugged mountains in the interior.[2]
Rain pattern	There are two distinct seasons: a wet season (November to April) and a dry season (May to October). An average of 75 per cent of Samoa's total annual rainfall occurs in the wet season. Its northern and western shores receive about 2,500 mm of rainfall, while inland areas receive about 7,500 mm per year.[2]
General dissipation of rivers and other water sources	The longest river in Samoa is the Vaisigano River. However, there is some potential for hydropower development on both the Upolu and Savaii Rivers.[2]

Electricity sector overview

Gross electricity generation in 2013 was 120.6 GWh with an installed capacity of 35 MW, increasing 7 per cent from the total generation of 111.7 GWh in 2012 (Figure 1).[3]

FIGURE 1

Electricity generation in Samoa (GWh)



Source: Ministry of Finance[3]

In 2013, diesel accounted about 70.85 per cent of total electricity generated, which indicates an increase from 2012 (66.41 per cent). Hydro produced about 29.14 per cent of total generation in 2013, reflecting a decrease of six per cent from 37.5 GWh in 2012 to 35.1 GWh in 2013. Rainfall recorded in the 12-month period in 2013 was mostly lower than the long-term average, causing the reduction of electricity generation from hydro sources. With other hydro projects in the pipeline with the Electric Power Corporation (EPC), there is a possibility of an increase in the generation of electricity from hydro sources once other potential hydro projects are commissioned. However, the contribution from hydro in the general electricity mix has been steadily decreasing. In 2000, 52 per cent of all electricity was generated using hydro. At the same time, diesel saw an increasing percentage to meet electricity demand. Coconut oil bio fuel blending by the EPC was terminated in 2012.

Apolima Island continued to enjoy clean energy from producing electricity using their 13.5-kW solar mini grid. In 2013, the electricity generated from this solar mini grid was 14.2 MWh. This was an increase of 36.8 per cent from 2012, where the electricity generated was 8.97 MWh.

Electricity generation, transmission and distribution are exclusively under the authority of the Electric Power Corporation, a state-owned enterprise. To date, Samoa has an electrification rate of 99 per cent of the whole population.

Electricity consumption, including that by both the prepayment meter and induction meter customers, accounted for 98.0 GWh in 2013 (81 per cent of total consumption). The commercial and manufacturing sectors' consumption accounted for 44 per cent of total consumption in 2013, constant with the consumption from 2012. The remaining total consumption of 56 per cent for 2013 is made up of other sub-sectors including government departments (10 per cent), schools (2 per cent), religious organizations (6 per cent) and residential users (28 per cent). The consumption by all sectors has shown either no change, or a decrease in consumption. Two exceptions to this are the school and industrial sector, which showed an increase of 1 per cent from 2012.

Electricity consumption in 2013 increased by approximately 5.5 per cent from 92.6 GWh in 2012 to 98.0 GWh in 2013. In 2013, the commercial and industrial sector consumption recorded 49.6 GWh and accounted for 51 per cent of total consumption. The residential sector consumption recorded 27.8 GWh and accounted for 28 per cent of the total consumption. The remaining sectors (hotels, government departments, schools and religious groups) recorded a total consumption of 20.5 GWh and accounted for 21 per cent.

The main reason for the increase of electricity generation in 2013 was the increasing power demand for continuous construction works, in order to prepare for the Small Islands Development States Meeting held in September 2014. Another reason was development of new households, as well as several new government buildings such as the new Ministry of Health, Ministry of Education, Ministry of Sports and Culture, the Tui Atua Tupua Tamasese Efi Building and the convention centre.

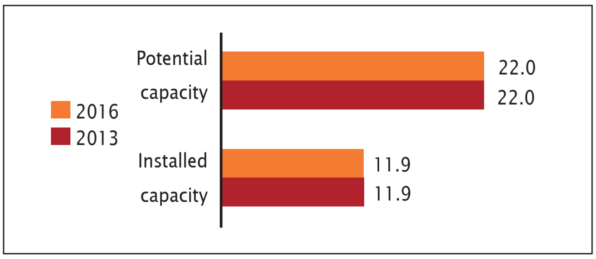
The Electric Power Corporation (EPC) continues to implement the Electricity Sector Expansion Project (PSEP) and continues to explore other Renewable Energy (RE) sources that are feasible for Samoa in order to reduce the heavy reliance on diesel. With the new Electricity Act allowing Independent Power Producers (IPPs) to generate electricity and sell to the EPC, there are a lot of IPPs interested in generating electricity from different RE sources. The EPC's new power station in Fiaga, Aleisa was opened in 2013 and is currently in operation. The EPC has also commissioned a few RE projects such as a solar project funded by the Pacific Environment Community Fund (PEC Fund), another solar project funded by NZAID and a wind project funded by the United Arab Emirates. Electricity tariffs range from US$0.38-US$0.45/kWh.

Small hydropower sector overview and potential

There are five hydropower plants on the island of Upolu, providing approximately 29 per cent of Samoa's total electricity production. These are the Afulilo Dam (4 MW), Lalomauga (3.5 MW), Fale ole F'ee (1.6 MW), Alaoa (1 MW) and Samasoni (1.8 MW). The Afulilo Dam is the only reservoir-type plant, while the rest are all run-of-river plants. In 2012, Hurricane Evan damaged three small hydropower (SHP) plants: Fale ole F'ee, Alaoa and Samasoni.[3] As no new comprehensive research on potential SHP capacity has been conducted, the estimate is the same as that in the *World Small Hydropower Development Report* (*WSHPDR*) *2013*, at 22 MW (Figure 2).[6]

FIGURE 2

SHP capacities 2013-2016 (MW) in Samoa



Sources: *WSHPDR 2013*,[6] Ministry of Finance[3]
Note: The comparison is between data from *WSHPDR 2013* and *WSHPDR 2016*.

Renewable energy (RE) development and power sector rehabilitation projects will support the government policy to increase power generation from renewable sources, rehabilitate damage to the power sector caused by Hurricane Evan, as well as to increase the power sector's resilience to future natural disasters. It will rehabilitate three SHPs on Upolu and construct three new SHPs on Upolu and one in Savai'I. These power plants will be Faleaseela (0.19 MW), Tafitoala (0.46 MW), Faleata (Savaii) (0.16 MW) and Fuluasou (0.68 MW).[4] The project will also provide training to the Electric Power Corporation on operation and maintenance of the SHPs, for up to two years after plant commissioning. The project will result in greater energy security and sustainability for Samoa.

Renewable energy policy

The Samoa Energy Sector Plan 2012-2016 outlines the Government of Samoa's overarching targets to reduce the import volume of fossil fuels by 10 per cent by 2016, as well as to achieve the goal of 100 per cent RE electricity generation by 2017. This will be done by promoting RE and energy efficiency across all sectors. Several projects that involves integrating RE into energy production are being carried out by independent power producers, development partners and donors, as well as by energy stakeholders, such as the Ministry of Finance's Energy Unit, the Ministry of Agriculture, the Ministry of Natural Resources and Environment, and the Electric Power Corporation.[5]

Barriers to small hydropower development

- Lack of monitoring data on water resource potential around the country;
- Resistance of communities to allow hydropower development in local river systems;
- Existing hydropower schemes in Samoa have experienced decreasing load factors due to change in climate and in part due to removal of vegetation in the catchments. Some reforestation is proposed along with investigating means to add storage with flood retention schemes upstream of existing facilities.

***Note**: The following countries are not included in this Report –*

Eastern Africa: Comoros, Eritrea, Mayotte, Seychelles and Somalia
Middle Africa: Chad
Northern Africa: Libya and Western Sahara
Western Africa: Cabo Verde, Guinea-Bissau, Mauritania, Niger and Saint Helena
Caribbean: Antigua and Barbuda, Bahamas, Barbados and Trinidad and Tobago
Northern America: Bermuda, Saint Pierre and Miquelon
South America: The Falkland Islands (Malvinas), Suriname and Venezuela
Southern Asia: Maldives
South-Eastern Asia: Brunei and Singapore
Western Asia: Bahrain, Cyprus, Israel, Kuwait, Omar, Qatar, State of Palestine, United Arab Emirates and Yemen
Southern Europe: Andorra, Gibraltar, Holy See, Malta and San Marino
Western Europe: Liechtenstein and Monaco

Technical Notes and Abbreviations

The findings of the *World Small Hydropower Development Report 2016* were arrived at by totalling data from a wide range of sources. Methodologies vary greatly from source to source, with an inevitable compromise of data integrity to varying degrees. One obvious issue is the lack of a universally agreed definition for small hydropower. While some countries define their small hydropower plants with a capacity of up to 1 MW, others include plants with capacities up to 30 MW or 50 MW. Nonetheless, a widely accepted definition of small hydropower is of plants up to 10 MW and, where possible, data have been provided according to this definition and care has been taken to indicate differing definitions within individual country reports.

An additional issue arises from the varying accuracy and specificity of estimated potential figures. For many countries, accurate assessments of potential capacity are difficult to establish. While care has been taken to provide the most accurate data, it should be noted that the information presented has been derived from various sources that are often unclear as to whether the estimate is theoretical, technical or economically feasible. Furthermore, not all countries have been able to identify their small hydropower potential and, in some cases, planned small hydropower projects have been reported instead. In other cases, data on potential were completely unavailable and already developed capacity was used to indicate the minimal available potential. Thus some countries would have been misrepresented to appear as having fully developed small hydropower resources. Where this occurs, care has been taken to make it clearer. However, it should be highlighted that despite the limitation on data, it is likely there is some level of small hydropower potential remaining in these countries.

When comparing data with the *World Small Hydropower Development Report 2013*, increases and decreases in installed capacity and estimated potential are, on occasion, due to the use of different or more accurate studies, and as such do not always reflect actual changes in small hydropower development. In other cases, plant improvements have led to higher capacities that moved individual plants above the 10 MW threshold and are therefore no longer included in the small hydropower figures. In general, however, differences between the Reports should be considered reflective of a growing degree of accuracy as much as they are an indication of additional small hydropower capacity or potential.

This Report covers 160 countries. Countries that were not included were those that had no known installed small hydropower capacity, potential or for which the data were inaccessible to the point that precludes a full country report. Countries adhered to the geographical regions and composition defined by the United Nations Statistics Division. Melanesia, Micronesia and Polynesia do not contain many countries or territories that use small hydropower and were therefore combined under the regional heading of 'Pacific Island Countries and Territories (PICT)'. This report was compiled for both 'countries' and 'territories'. Overseas territories have been included in the continent where they are geographically located following the online M49 list of the United Nations Statistics Division. Countries that are not part of the United Nations were not considered in this Report. In some cases, the terms 'country' and 'territory' may be used interchangeably. This does not imply an opinion on the legal status of any country or territory.

List of abbreviations

ADB	Asian Development Bank
AfDB	African Development Bank
CER	Certified Emission Reduction
CDM	Clean Development Mechanism
CSP	Concentrated solar power
EBRD	European Bank for Reconstruction and Development
ECOWAS	Economic Community of West African States
EIA	Environmental Impact Assessment
ESHA	European Small Hydropower Association
FIT	Feed-in tariff
GEF	Global Environment Facility
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
JICA	Japan International Cooperation Agency
NEP	National Energy Policy
OLADE	Latin American Energy Organization (Organización Latinoamericana de Energía)
PICT	Pacific Island Countries and Territories
PPA	Power Purchase Agreement
PPP	Public Private Partnership
RE	Renewable energy
RET	Renewable energy technology
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNESCO	United Nations Educational, Scientific and Cultural Organization
UNFCCC	United Nations Framework Convention on Climate Change
VAT	Value Added Tax
WFD	Water Framework Directive

Technical abbreviations

Hz	Hertz	MW	Megawatt
kW	Kilowatt	Rpm	Rate per minute
kWh	Kilowatt hour	m3/s	Cubic metre per second
GWh	Gigawatt hour	kWp	Kilowatt peak
l/s	litre/second	CO2	Carbon dioxide
MVA	Mega Volt Ampere		

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