IRENA

International Renewable Energy Agency

# WEST AFRICAN POWER POOL:

## Planning and Prospects for Renewable Energy

## About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future, and serves as the principal platform for international cooperation, a centre of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy, in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity.

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## Disclaimer

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# MODEL FILES DOWNLOAD

All data and results presented here are available on the IRENA website: www.irena.org/WAPP.

The analysis presented here corresponds to following version of the model files.

- MAINWAPP_2013-05-15_1526.zip (SPLAT-W model file)
- Demand_ALL_revised2012_AM.xlsx (Electricity demand data assumptions)
- Transmission Data_02.xlsx (transmission lines and projects)
- WAPP_Supply_16_BY_Wind_CIExist_Fixed.xlsm (technology data file)
- 0REFERENCE_v12.xlsm (results file for the WAPP Reference Scenario)
- 1RE_v12.xlsm (results file for the Renewable Promotion Scenario)
- 1bRE_noInga_v12.xlsm (results file for the No Central Africa Import Scenario)
- 1cRE_limTrade_v12.xlsm (results file for the Energy Security Scenario)
- Summary_ECOWAS_v12c.xlsx (ECOWAS Summary)
- Load_Calibration_all_01_for report.xlsm (load data file)

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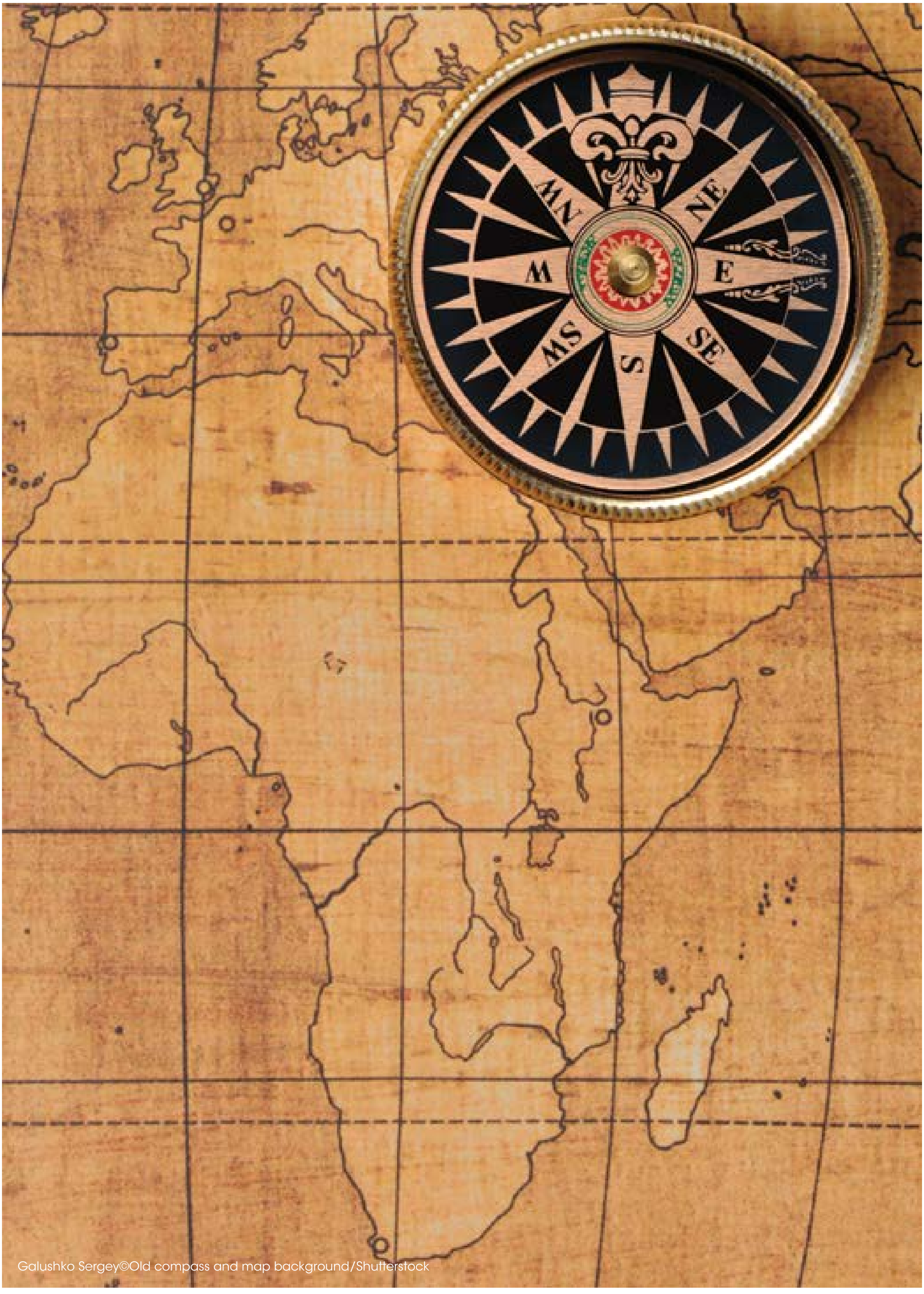


Galushko Sergey©Old compass and map background/Shutterstock

# Abbreviations

| | |
|---|---|
| **CCGT** | Combined Cycle Gas Turbine |
| **CSP** | Concentrated Solar Power |
| **ECOWAS** | Economic Community of West African States |
| **ECREEE** | ECOWAS Regional Centre for Renewable Energy and Energy Efficiency |
| **GWh** | Gigawatt-hours |
| **IAEA** | International Atomic Energy Agency |
| **IRENA** | International Renewable Energy Agency |
| **GJ** | Gigajoules |
| **kV** | Kilovolt |
| **LCOE** | Levelised Cost of Electricity |
| **MESSAGE** | Model for Energy Supply Strategy Alternatives and their General Environmental Impact |
| **MW** | Megawatt |
| **OCGT** | Open Cycle Gas Turbine |
| **O&M** | Operations and Maintenance |
| **PV** | Photovoltaic |
| **SPLAT-W** | System Planning Test Model for Western Africa |
| **T&D** | Transmission and Distribution |
| **TWh** | Terawatt-hours |
| **USD** | United States Dollars |
| **WAPP** | West African Power Pool |

Trevor Kittelty©African fishermen on river with sun setting behind them/Shutterstock

# Executive Summary

The International Renewable Energy Agency (IRENA) has developed a power sector planning tool for West African countries called the System Planning Test model for Western Africa (SPLAT-W, or SPLAT for short) which enables analysts to design a power system that meets various system requirements, including reliability amid growing, fluctuating electricity demand. It also takes into account investment and running costs.

Using the SPLAT-W model, IRENA developed a Renewable Promotion Scenario for continental countries of the Economic Community of West African States (ECOWAS). This is intended to demonstrate how SPLAT-W can be used, and to stimulate discussion about assumptions and results. In this scenario, IRENA assessed investment needs for power generation, both on- and off-grid, for domestic transmission and distribution, and for international transmission networks to meet growing regional power demand in the most affordable manner. Existing capital stock, replacement needs and committed investments were explicitly considered. Emphasis was given to integrating renewable technology generation into on- and off-grid power systems, taking into account the differences between generation technologies in responding to demand fluctuation. All continental ECOWAS countries were assessed jointly, providing insights on the need for investments into regional electricity interconnectors. All data and results presented here are available on the IRENA website: www.irena.org/WAPP.

IRENA's assessment shows that the share of renewable technologies in the region could increase from the current 22% of electricity generation to as much as 52% in 2030, provided that the cost of these technologies continues to fall and fossil-fuel prices continue to rise. In this scenario, nearly half of the envisaged capacity additions between 2010 and 2030 would be with renewable technologies. Mini-hydro generation technology, where suitable resources exist, could become significant for supplying rural electricity demand. Total investment required in the region would amount to nearly USD 170 billion (undiscounted) between 2010 and 2030. Despite conservative assumptions on renewable resource availability and penetration limits for wind and solar technologies, the share of renewable energy technologies in 2030 under this scenario would be substantially higher than the regional target for renewables in the power sector (31% of on-grid power production from renewables by 2030), set by the ECOWAS Renewable Energy Policy. Hydro generation alone would account for 33% of the total generation.

While IRENA has used publicly available information to represent the current power-supply infrastructure, further validation by local experts would enhance the model's robustness. Moreover, the assessment is based on certain assumptions, including, but not limited to, fuel costs, infrastructure and policy developments, which energy planners in the region might regard differently. It is recommended that local experts explore different assumptions and develop and compare their own scenarios to analyse the benefits and challenges of accelerated deployment of renewables.

With the aim to assist ECOWAS member states in developing National Renewable Energy Action Plans under the ECOWAS Renewable Energy Policy, IRENA and the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) have begun enhancing the SPLAT-W tool beyond what is documented in this report. Over the next two years, further methodological improvements regarding the representation of renewable technologies will be implemented, and local experts in the region will be engaged in a bid to improve the data. In parallel, IRENA, together with partner organisations, has been planning to set up capacity building support in the use of the energy system modelling approach for renewable energy planning.


Trevor Kittelty©A Tuareg man walking up a sand dune in the Sahara desert/Shutterstock

# 1. Introduction

Africa needs to significantly improve its electricity supply in order to enhance energy access for its growing population and provide the means for economic growth. Africa has great domestic renewable energy potential, which could be used to provide much needed energy in an affordable and secure manner, and to contribute to universal access to modern energy while avoiding negative environmental impact. A long-term vision is needed to make the best use of available domestic resources, given the long-lasting nature of energy infrastructure. Since different power supply technologies have different operational characteristics that could complement each other, the deployment of renewable technologies cannot be planned in isolation from the rest of a power system, but rather needs to be looked at from the perspective of their integration into the system.

The International Renewable Energy Agency (IRENA) aims to assist its member countries with energy system planning to make a transition to an energy system that makes maximum use of environmentally benign, fossil-free renewable technologies. IRENA's earlier work, Scenarios and Strategies for Africa, was a major input to the IRENA-Africa High Level Consultations on Partnership on Accelerating Renewable Uptake for Africa's Sustainable Development, held in Abu Dhabi in July 2011, at which Ministers of Energy and heads of delegation of African countries announced a communique recognising the IRENA's role in promoting renewable energy to accelerate Africa's development (IRENA, 2011a).

IRENA has since taken up a number of research projects to provide a solid factual basis supporting policy decision-making. This report presents some of power system planning scenarios for the Economic Community of West African States (ECOWAS), which describe a long-term (*i.e.*, until 2050) transition to a renewable-oriented future for national power systems in the region. This can be accelerated by taking into consideration the long-term cost-reduction potential of renewable energy technologies. Technically feasible and economically favourable transition paths were computed by a power system modelling tool, the System Planning Test model for West Africa (SPLAT-W, or SPLAT for short), in which the retirement of current power infrastructure, geographical distribution of renewable resources, generation adequacy of the system and other factors were taken into account. The assessment considers economic and social implications of adopting renewable energy, including investment needs, fuel savings, energy security, etc. The exercise is part of a series that IRENA has been conducting for the five power-pool regions in Africa, covering all continental African countries.

The SPLAT-W model is built on the database of the West African Power Pool (WAPP) system, which consists of existing generation units, international transmission lines and a range of future technology options. SPLAT calculates future configurations of the power system based on specified system requirements, in order to meet a given range of electricity demand fluctuations. The configuration of the power system is defined primarily by minimising total energy system costs over the planning period (*i.e.*, 2010-2050).

WAPP recently published the Draft Final Report of the Update of the ECOWAS Revised Master Plan for the Generation and Transmission of Electrical Energy (WAPP, 2011), in which different power generation and transmission projects are analysed and evaluated from a techo-economic perspective. The economic evaluation of different planning scenarios, combining different policy actions and uncertainties, was done using a power-system optimisation tool. The WAPP Master Plan uses these scenarios to identify priority investment projects.

The SPLAT-W model starts out by duplicating the reference scenario of the WAPP Master Plan, ensuring the compatibility in the underlying approach of the model with actual regional energy plans. This study's primary value addition is that insights from IRENA's latest analytical work on renewable technology development and renewable resource potential are reflected in the database and modelling approach. The Renewable Promotion Scenario presented in this report shows that a more aggressive deployment of renewable technology than the one in the WAPP Master Plan reference scenario would be feasible and even economical. Its secondary additional value is that the SPLAT-W model is built on a modelling framework that is well maintained and can be obtained free of charge. SPLAT-W is designed to be transferred to interested organisations in IRENA member countries so that they can use it to explore alternative scenarios for national and regional power sector development. Several SPLAT-W model tutorials have been developed by IRENA and the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) and made available at www.irena.org/WAPP.

SPLAT-W covers all the continental ECOWAS countries: Burkina Faso, Cote d'Ivoire, Gambia, Ghana, Guinea, Guinea-Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone, and Togo/Benin (treated as a single node).

Wind Power in West Africa (ECREEE)

# 2. Overview of Methodology

SPLAT-W was developed using a modelling platform, the Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE), a dynamic, bottom-up, multi-year energy system modelling framework that applies linear and mixed-integer optimisation techniques. The modelling platform was originally developed at the International Institute of Applied System Analysis (IIASA), but was more recently modified by the International Atomic Energy Agency (IAEA). The modelling platform is the framework within which the actual model is developed.

The MESSAGE modelling platform consists of a database which needs to be populated with energy demand and load projections, economic and technical parameters of energy resources and energy supply options, including power plants, transmission and distribution (T&D) lines, electricity trades and information regarding existing capital stock and remaining power-plant life spans. IRENA developed the SPLAT-W model by populating the database, configuring it to replicate the existing power infrastructure in each country and setting up various scenarios to provide a quantitative picture of future power system development. Investment and operation "decisions" for plants that are under consideration (*i.e.*, planned but not yet built), along with generic capacity representing futher future expansion, reflect the least-cost optimisation approach that is built into the MESSAGE platform.

The least-cost optimisation procedure defines the operation and investment schedule that minimises total discounted system costs (including investment, operation and maintenance (O&M), fuel and any other user-defined costs) over the planning period, while meeting various system requirements (*e.g.*, supply matching demand at a given time; sufficient resources and capacity in place to supply desired production) and user-defined constraints (*e.g.*, reserve margin, speed of technology deployment, emission limits, policy targets). The model reports on the mix of technologies and fuels that achieves a least-cost power-system configuration for given demand levels. The economic, environmental and social implications associated with the identified least-cost power systems can be easily calculated using the platform.

Using the MESSAGE platform, the IAEA has developed a model and training materials to analyse least-cost power systems for the coming 20 years in the ECOWAS region. The model developed by the IAEA was further enhanced by IRENA in two respects. First, in order to better reflect the role of decentralised power systems, for which renewables can offer a significant cost advantage over fossil-based options, power demand was split into three main categories:

» industrial;

» urban;

» rural.

This is important as the shape of the load curve and the connection to the grid differs markedly between categories. Different distributed generation options are available for each category. Second, the set of renewable energy supply options was also expanded and significantly refined. The latest technology cost data and capacity factor data were used, based on IRENA renewable energy costing and technology assessment studies. Data on the quantity and quality of renewable energy resources was updated and refined, using data collected during IRENA's work on the Global Renewable Energy Atlas.

In the SPLAT-W model, countries are modelled as separate nodes inter-linked by transmission lines. Each node, representing the power system of a single country, is characterised as shown in Figure 1. Once demand is specified, a technically feasible, least-cost power-supply system that meets the given demand while satisfying all constraints is computed for the modelling period. "Least cost" is defined for the region as a whole and for the entire modelling period. SPLAT-W considers four types of power-generation options: existing power plants; power plants to be commissioned; site-specific power plant projects under consideration (candidate projects); and non-site specific (generic) future power capacity. Plants listed in the first three categories follow the WAPP Master Plan.

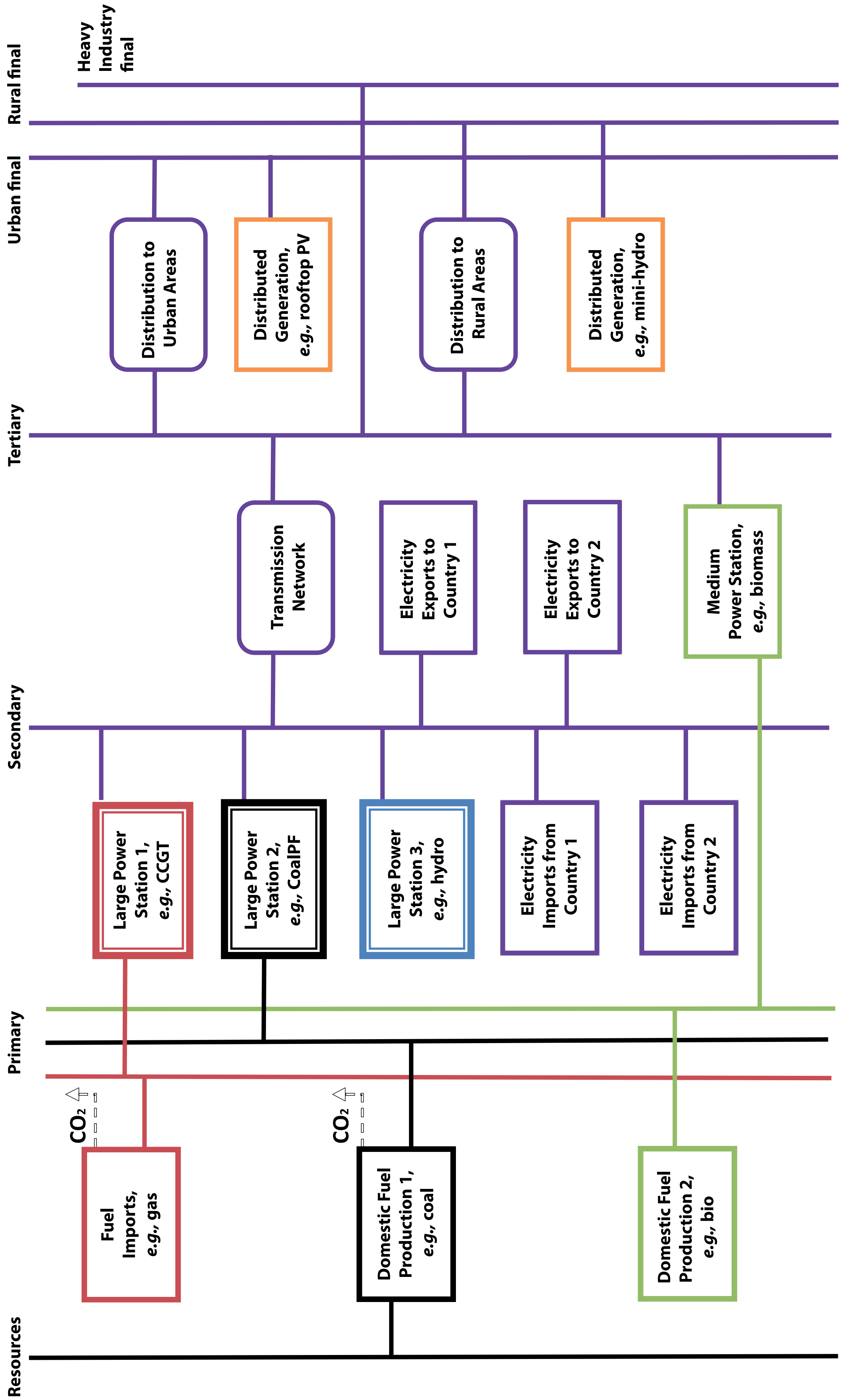


Figure 1. Country Power Sector Model Structure

# 3. Scenario Assumptions

## 3.1 THE FOUR SCENARIOS

One Reference Scenario and three variations of the Renewable Promotion Scenario (Renewable Energy Policy, No Central Africa Import, and Energy Security) have been assessed. The Reference Scenario is compatible with the WAPP Master Plan reference scenario, but includes mining demand (which is about 8% higher than in the WAPP Master Plan reference scenario for 2025). The system has been optimised at the regional level, with electricity trade allowed within ECOWAS. Only those cross-border transmission projects currently under consideration (decided or candidate) are included as future options to be optimised by the model. Some important differences from the reference scenario in the WAPP Master Plan are:

» Inclusion of decentralised electricity supply options;

» Segregation of rural / urban / industrial electricity demand;

» Updating of renewable energy resource potential and technology cost data; and

» Conservative assessment of hydro projects using a "dry year" generation assumptions.

As in the WAPP Master Plan, decided projects are commissioned at fixed dates, while candidate projects are regarded as investment options from a given date: 2014 for thermal and 2018 for hydro projects. An option to import electricity from the Central African region is not included in the WAPP Master Plan, and thus not included in our Reference Scenario either.

In the Renewable Promotion Scenario, cost reductions due to anticipated technology learning are taken into account for renewable energy technologies, consistent with past trends (IRENA, 2013a). This is in contrast to the assumption adopted in the WAPP Master Plan's reference scenario, to which our Reference Scenario was calibrated. Also, unlike in our Reference Scenario, fossil-fuel prices are assumed to escalate.

An option to import electricity from the Central African region, with vast hydro resources (notably the Grand Inga project) is included in all but one scenario.

In the No Central Africa Import Scenario, these electricity import options from the Central African region are excluded.

Finally in the Energy Security Scenario, import shares are limited to 25% of total electricity demand for each country. Countries that already have imports higher than 25% are modelled with a gradual reduction to 25% by 2030.

To ensure that the resulting energy system is reliable, conservative views on resource potential, the capacity of intermittent renewable sources, and penetration limits are retained throughout the analysis. This is a short-cut representation of system reliability. In the next round of model improvement, it will be enhanced: by refining intermittent renewable capacity to reflect the geographic dispersion of resources within each country; adding system integration costs for renewables; refining the assessment of exclusion zones when estimating solar and wind resource potential; and conducting sensitivity analysis on hydro generation. Representing system reliability in energy system models with a large share of renewables is the subject of on-going research around the world. IRENA keeps up and adopts the latest methodological improvements, within the parameters of the current modelling platform.

## 3.2 OVERALL ASSUMPTIONS

Overall assumptions across all scenarios are as follows:

» The real discount rate applied is 10%, consistent with the assumption in the WAPP Master Plan.

» The monetary unit used throughout is the US dollar (USD) at 2010 rates, with adjustments made for monetary data from other years using the World Bank's gross domestic product (GDP) deflator for the United States (World Bank, 2011).

- The study spans 2010–2050, with a focus on 2010–2030.
- In order to capture the key features of electricity demand load patterns, a year is characterised by three seasons: pre-summer (January–April); summer (May–August); and post-summer (September–December). Pre-summer and summer days are characterised by three blocks of equal demand: day (6 a.m.–6 p.m.), evening (6 p.m.–11 p.m.) and night (11 p.m.–6 a.m.). Post-summer days include an additional block (7 p.m.) to capture the daily demand peak.
- In order to ensure system reliability, penetration of intermittent renewables is limited, conservatively, to 10% of total generation (prior to transmission) for solar and 20% for wind.

## 3.3 ASSUMPTIONS ABOUT ELECTRICITY DEMAND

The main source used for electricity demand projections is the WAPP Master Plan (WAPP, 2011), which projects secondary electricity demand (*i.e.*, at the utility level, before transmission) to 2025, with mining projects handled separately in some cases. The demand projections considered in our Reference Scenario, however, include mining projects. Post-2025 demand is simply extrapolated from the growth projected in the WAPP Master Plan for the period 2020-2025. Figure 2 shows the evolution of secondary electricity demand, which is dominated by Nigeria.

Projections for Guinea, Guinea Bissau, Liberia and Sierra Leone include demand for mining projects that is projected to be several times larger than all other electricity demand. Other mining projects in the West African region, such as gold mining in Burkina Faso, were not identified in the WAPP Master Plan and are not included in this analysis.

Each country's secondary electricity demand was divided into the following categories:

- Heavy industry (*e.g.*, mining), which connects to generation at a high voltage and generally requires little T&D infrastructure;
- Urban (residential, commercial and small industries), connected via a moderate amount of T&D infrastructure;
- Rural (residential and commercial), which requires the most extensive T&D infrastructure.

A detailed bottom-up analysis, which would be required to calculate the exact distribution of demand in these categories, is beyond the scope of this work.

Here, a simple and basic approach was adopted:

- WAPP Master Plan projections of secondary electricity demand was the baseline for electricity demand projections.
- The subsequent energy balances (where available) were then used to split base-year consumption into "heavy industry" and "other", with adjustments made for differences in loss, assuming that heavy industry has lower losses.
- The evolution of the split in the base-year consumption over time was estimated, assuming that a small share of electricity demand originated from rural areas.
- For some countries, the WAPP Master Plan explicitly states the electricity demand for certain mining or industrial projects. This additional demand was completely allocated to "heavy industry", with the remaining demand allocated to "urban" and "rural" sectors.

Final electricity demand, extrapolated based on this approach, is given in Figure 3 for each demand category. Detailed country-by-country data is found in Table 13, Appendix A.

Each demand category is characterised by a different load profile. These profiles are assumed to be common to all countries and are defined by shares of demand in each season (pre-summer, summer, and post-summer) and each part of the 24-hour day (daytime, evening and night).

Since demand in reality differs between countries, actual load profiles for the various seasons and parts of the day are country-specific. As an example, load-shape data for Ghana in 2012 is shown in Figure 4.

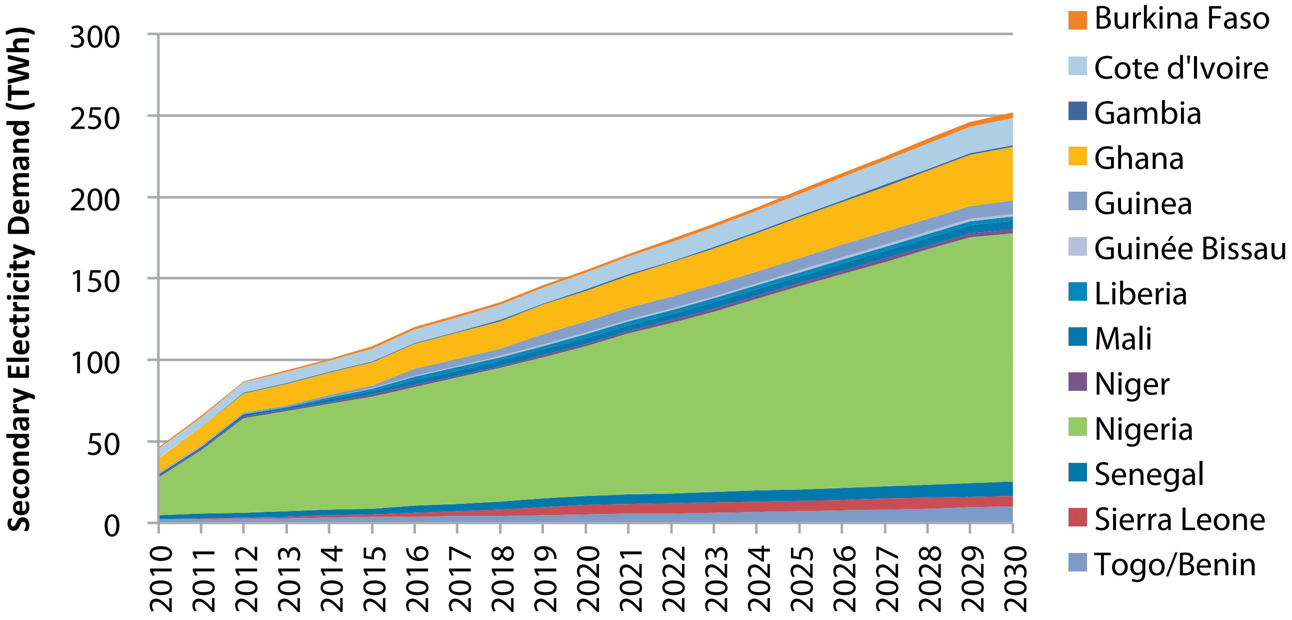


Figure 2. Secondary Electricity Demand Projections with Mining Projects

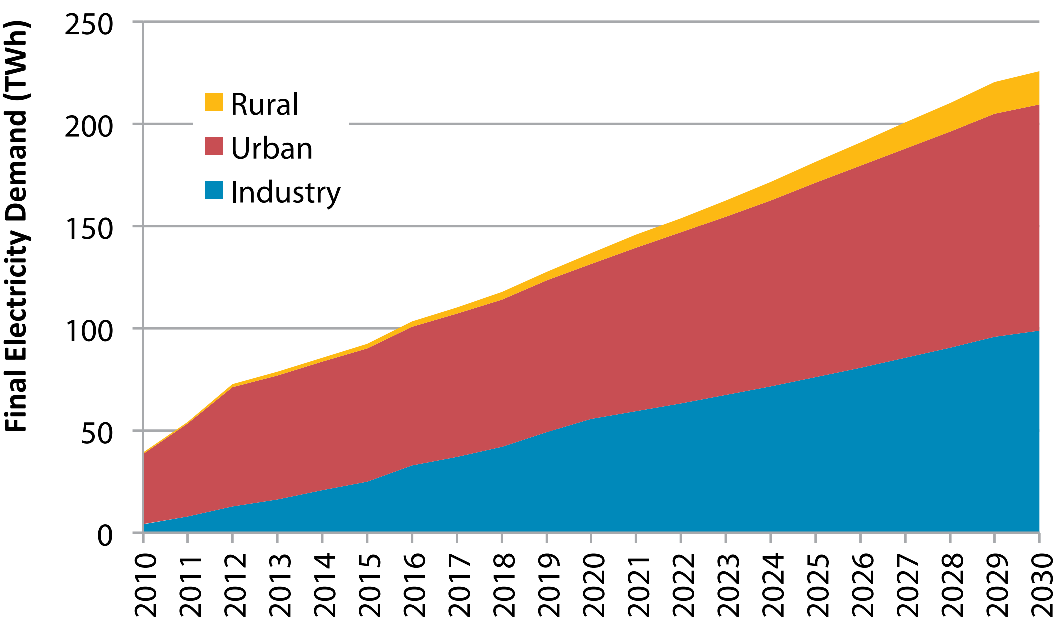


Figure 3. Total Final Electricity Demand, 2010-2030, by Category

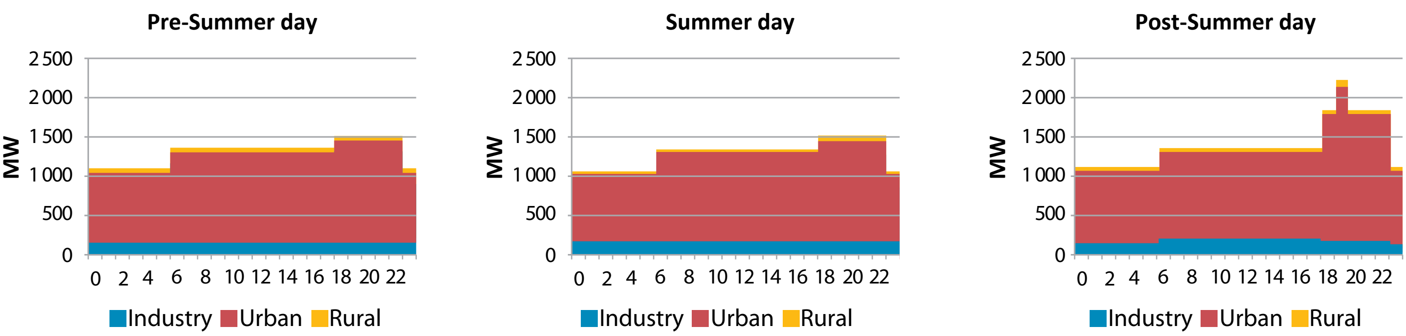


Figure 4. Load Shape Data: Ghana in 2012

## 3.4 ASSUMPTIONS ON LOCAL TRANSMISSION AND DISTRIBUTION

T&D infrastructure needs investment in order to meet peak system demand. The required investment in T&D infrastructure (*i.e.*, grid-connected, not taking into account demand met by off-grid technologies) is modelled to exceed peak system demand by some margin, which in turn determines installed capacity. Costs and losses are defined for each demand category, reflecting the different levels of T&D infrastructure required. Off-grid technologies, requiring no T&D infrastructure, entail no costs and losses. Costs and losses for distribution through mini-grid solutions were disregarded for the sake of simplification.

T&D infrastructure costs are assumed lowest to heavy industry, medium to urban, and the highest to rural demand category and kept constant over time. The assumptions on T&D losses are specific to each country. For industry, losses are assumed 7% for 2010, and are reduced to 5% by 2030. For the urban demand category, they are assumed 17-30% for 2010 and are reduced to 13% by 2030 in all countries. The losses are highest to the rural demand category, 20-35% for 2010 and are reduced to 25% by 2030 in all countries. The losses by country and by demand category are given in Appendix D. The T&D losses shown in Table 1 corresponds to the average values used to calculate the levelised cost of electricity (LCOE) which are further discussed in Section 3.7 and Table 9.

Table 1. Assumptions for Transmission and Distribution Infrastructure Costs[1] and Losses

| | Cost (USD/kWh) | Average Losses | | |
|---|---|---|---|---|
| | | 2010 | 2020 | 2030 |
| **Heavy Industry** | 0.015 | 7% | 7% | 5% |
| **Urban Residential/ Commercial/Small Industries** | 0.05 | 20% | 15% | 13% |
| **Rural Residential/Commercial** | 0.10 | 30% | 25% | 25% |

Table 2. Existing Hydro and Identified Hydro Projects

| | Existing Hydro | | | Identified Hydro Projects | | |
|---|---|---|---|---|---|---|
| **Country** | **Capacity** | **Average Generation** | **Dry-Year Generation** | **Capacity** | **Average Generation** | **Dry-Year Generation** |
| | MW | GWh | GWh | MW | GWh | GWh |
| **Burkina Faso** | 23 | 91 | 41 | 60 | 192 | 146 |
| **Cote d'Ivoire** | 585 | 2,424 | 1,842 | 1,072 | 4,953 | 2,916 |
| **Gambia** | 0 | 0 | 0 | 68 | 241 | 92 |
| **Ghana** | 1,044 | 5,051 | 3,722 | 661 | 2,330 | 1,010 |
| **Guinea** | 95 | 482 | 379 | 3,346 | 14,296 | 10,974 |
| **Guinea-Bissau** | 0 | 0 | 0 | 14 | 48 | 18 |
| **Liberia** | 0 | 0 | 0 | 967 | 4,763 | 3,633 |
| **Mali** | 153 | 683 | 495 | 434 | 2,003 | 1,342 |
| **Niger** | 0 | 0 | 0 | 279 | 1,269 | 486 |
| **Nigeria[2]** | 1,358 | 7,476 | 4,632 | 10,142 | 43,710 | 33,220 |
| **Senegal** | 68 | 264 | 165 | 530 | 1,988 | 1,100 |
| **Sierra Leone** | 56 | 321 | 158 | 755 | 4,168 | 3,468 |
| **Togo/Benin** | 65 | 173 | 91 | 357 | 1,004 | 722 |
| **Total** | **3,447** | **16,965** | **11,525** | **18,682** | **80,964** | **59,129** |

[1] Note that the costs of the distribution technologies are modelled as investment cost based on the load factor of each of the demand categories and not as a variable cost, *i.e.*,. the cost in the table shows the levelised cost of distribution.

[2] In Nigeria there is 3,300 Megawatts (MW) of identified hydro projects. The rest is based on REMP (2005), which identified a total potential of 11,500 MW of large hydro for Nigeria.

## 3.5 ASSUMPTIONS ABOUT RENEWABLE RESOURCE POTENTIAL

### Large Hydro

Large-hydro potential is limited to the identified hydro sites in the WAPP Master Plan (WAPP, 2011), summarised in Table 2. A "dry-year" is assumed for all hydro sites in all years within the modelling period. This underplays the role of hydro in the region but is considered prudent in view of the vulnerability of West Africa to drought years. A more comprehensive, stochastic approach (as used in WAPP, 2011) was impossible due to limitations of the MESSAGE modelling platform. Detailed parameters for existing and planned hydro projects are given in Table 15 and Table 17 in Appendix B.

### Other Renewable Energy Potential

Estimates for renewable resource potential other than large hydro are shown in Table 3. Estimates for solar are based on the Mines ParisTech[3] dataset, while wind estimates are based on the Vortex data set (9 km resolution), as reported by IRENA (2013b). These may underestimate actual potential, given that only 1% of the suitable land area is considered available for solar, and 0.25% for wind generation. Yet the potential is so vast that no country is expected to reach its resource constraints by 2030.[4] Mini-hydro data is based on UNIDO (United Nations Industrial Development Organisation)/ ECREEE (2010), while biomass data is based on IRENA (2011b).

## 3.6 ASSUMPTIONS ABOUT FUEL AVAILABILITY AND PRICES

Three types of gas supply are assumed to be available: locally produced gas, in Nigeria, Cote d'Ivoire, and Ghana; Nigerian gas exports, supplied through the Western African Gas Pipeline to Ghana, Togo and Benin; and imported liquefied natural gas (LNG) in other coastal countries.

For petroleum products, three types of fuel are distinguished: heavy fuel oil (HFO), distillate diesel oil (DDO), and light crude oil (LCO). Different prices are assumed for petroleum products delivered to coastal countries as opposed to inland countries.

For coal, only Nigeria and Niger are assumed to have resources for local production. Apart from Nigeria all other coastal countries have the option of coal imports, which for the purpose of modelling are assumed to be available.

Table 3. Estimates of other Renewable Energy Potential

| Country | Mini Hydro | CSP | Solar PV | Biomass | Wind 20% | Wind 30% |
|---|---|---|---|---|---|---|
| | MW | TWh | TWh | MW | MW | MW |
| **Burkina Faso** | 140 | 18.1 | 77.4 | 2,250 | 4,742 | 29 |
| **Cote d'Ivoire** | 242 | 2.2 | 103 | 1,530 | 491 | 0 |
| **Gambia** | 12 | 3.2 | 4.74 | 23.75 | 197 | 5 |
| **Ghana** | 1 | 2.3 | 76.4 | 1,133 | 691 | 9 |
| **Guinea** | 332 | 4.7 | 52.0 | 656 | 2.4 | 0 |
| **Guinea-Bissau** | 2 | 9.0 | 14.9 | 71 | 142 | 0 |
| **Liberia** | 1,000 | 0.0 | 6.67 | 459 | 0 | 0 |
| **Mali** | 67 | 36.2 | 79.1 | 1,031 | 2,195 | 0 |
| **Niger** | 50 | 88.3 | 157 | 1,115 | 16,698 | 5,015 |
| **Nigeria** | 3,500 | 100 | 325 | 10,000 | 14,689 | 363 |
| **Senegal** | 104 | 15.4 | 75.2 | 475 | 6,226 | 1,243 |
| **Sierra Leone** | 85 | 2.0 | 15.0 | 166 | 0 | 0 |
| **Togo/Benin** | 336 | 0.0 | 51.6 | 957 | 551 | 0 |

[3] HelioClim-3, developed by Mines ParisTech and operated by Transvalor, is a satellite-based database with a long history, where data and maps are offered via the SoDa online portal. Read more at: www.pv-magazine.com/archive/articles/beitrag/solar-resource-mapping-in-africa-_100009438/501/#ixzz2JNDgfV6q

[4] Solar potential would correspond to 2-100 times larger than the projected total electricity demand in each country in 2030, and only 3% of solar potential would be utilised in the Renewable Promotion Scenario.

Inland countries other than Niger are assumed to have no domestic coal resources or coal transport infrastructure, and coal costs in these countries are assumed to be prohibitively expensive.

Two types of biomass are distinguished based on price range. Countries with sufficient agriculture to potentially produce biomass for the power sector were allocated to the "moderate" price category. However, Burkina Faso, Niger and Mali, inland countries with limited agricutural resources are assigned to the "expensive" category.

Assumptions on fuel availability are summarised in Table 4. Base-year fossil fuel prices follow the WAPP Master Plan (WAPP, 2011). Prices for gas, oil products and coal in the base year of the Master Plan were derived from an assumed benchmark oil price of USD 100 per barrel. In the Reference Scenario, fossil-fuel prices are kept constant throughout the study period, as in the WAPP Master Plan. However, in the Renewable Promotion Scenario and its variations, future prices for oil products increase 20% by 2020 and 35% by 2030, compared to the base year. Gas prices escalate 10% between 2010 and 2020, and 30% by 2030. Domestic coal in Niger and Nigeria is set at a lower price compared to the landed price in coastal countries. Domestic coal prices are based on Idrissa (2004). The WAPP Master Plan in contrast does not distinguish clearly between the price for locally produced coal for Niger/Nigeria and imported coal for coastal countries.

The assumed price evolutions for fuels are summarised in Table 5.

Dennis Schroeder©SolarTAC test facility in Aurora, CO/NREL

### Table 4. Assumptions on Fuel Availability

| Country | Coal | Gas | Oil | Biomass |
|---|---|---|---|---|
| **Burkina Faso** | NA | NA | Inland | Scarce |
| **Cote d'Ivoire** | Import | Domestic | Coastal | Moderate |
| **Gambia** | Import | LNG | Coastal | Moderate |
| **Ghana** | Import | Domestic/Pipeline | Coastal | Moderate |
| **Guinea** | Import | LNG | Coastal | Moderate |
| **Guinea-Bissau** | Import | LNG | Coastal | Moderate |
| **Liberia** | Import | LNG | Coastal | Moderate |
| **Mali** | NA | NA | Inland | Scarce |
| **Niger** | Domestic | NA | Inland | Scarce |
| **Nigeria** | Domestic | Domestic | Coastal | Moderate |
| **Senegal** | Import | LNG | Coastal | Moderate |
| **Sierra Leone** | Import | LNG | Coastal | Moderate |
| **Togo/Benin** | Import | Pipeline | Coastal | Moderate |

### Table 5. Fuel Price Projections

| USD/GJ | 2010 | 2020* | 2030* |
|---|---|---|---|
| **HFO (delivered to the coast)** | 12.9 | 15.5 | 17.4 |
| **HFO (delivered to the inland)** | 16.3 | 19.6 | 22.0 |
| **Diesel (delivered to the coast)** | 21.9 | 26.3 | 29.6 |
| **Diesel (delivered to the inland)** | 25.2 | 30.2 | 34.0 |
| **LCO (delivered to the coast)** | 17.8 | 21.4 | 24.0 |
| **LCO (delivered to the inland)** | 18.9 | 22.7 | 25.5 |
| **Gas Domestic** | 8.5 | 9.5 | 11.0 |
| **Gas Pipeline** | 10.3 | 11.4 | 13.5 |
| **Gas Imported (LNG)** | 11.0 | 12.3 | 14.2 |
| **Coal Domestic** | 3.0 | 3.3 | 3.5 |
| **Coal Imported** | 4.6 | 5.0 | 5.3 |
| **Biomass Not Free** | 1.5 | 1.5 | 1.5 |
| **Biomass Scarce** | 3.6 | 3.6 | 3.6 |

* For the fossil fuels, prices in 2020 and 2030 are kept constant as in 2010 in the Reference Scenario.

## 3.7 ASSUMPTIONS ABOUT ELECTRICITY GENERATION OPTIONS

### Existing Generating Capacity

Existing thermal and hydro generation is based on WAPP (2011) and is summarised in Table 6. Detailed parameters are given in Table 14 and Table 15, Appendix B.

### Future Power Generation Options

There are two types of future power generation in the model: site-specific projects and generic technology options. Site-specific projects are taken from the WAPP Master Plan, with specified unit size, capacity factors, efficiency, O&M costs, investment costs, etc. Some projects are already "committed" and are sure to be a part of future energy mix. Other projects are "under consideration" and may or may not be included in each scenario computed by our model. Similarly, generic technology options may or may not be included.

Table 7 summarises power generation projects as per WAPP (2011). Detailed tables are given in Table 16 and Table 17, Appendix B.

In the SPLAT-W model, demand is first met by existing technologies and committed projects. Additional demand is met by site-specific projects, or by generic power-generation technologies, for which capacity is modelled without reference to specific unit sizes. Certain technologies are assumed to provide electricity only via the grid, while others are assumed to provide on-site electricity.

For thermal power generation, the following are included as generic options:

» Diesel/Gasoline, 1 kW system, for urban and rural uses

» Diesel, 100 kW system, for heavy industry

» Diesel, centralised, feeding the grid (pre-transmission)

» Heavy fuel oil, feeding the grid (pre-transmission)

» Open-cycle gas turbine (OCGT), feeding the grid (pre-transmission)

» Combined-cycle gas turbine (CCGT), feeding the grid (pre-transmission)

» Supercritical coal, feeding the grid (pre-transmission)

For renewable energy technologies, the following options are included as generic technologies:

» Small or mini-hydro, supplying rural electricity.

» On-shore wind, feeding the grid (pre-transmission), based on two wind regimes: one where the capacity factor is 30%, and the other where the capacity factor is 20%.

» Biomass, mainly in the form of co-generation to be consumed on-site, with surplus exported to the grid (pre-transmission).

» Utility solar photovoltaic (PV), referring to PV farms managed by the utility and feeding the grid (pre-transmission), modelled to only produce electricity during the daytime.

» Distributed or rooftop solar PV, supplying either urban or rural demand, modelled to only produce electricity during the daytime.

» Distributed or rooftop solar PV, 1-hour storage, with batteries allowing use slightly beyond daylight hours.

» Distributed or rooftop solar PV, 2-hour storage, with batteries allowing more extended use beyond daylight hours.

» Concentrated Solar Power (CSP), no storage, medium- to large-scale CSP feeding the grid pre-transmission.

» CSP, with storage, medium- to large-scale CSP with thermal storage, able to supply daytime and evening electricity.

For hydro power, given the lengthy lead time needed, only site-specific projects are included as future generation options, with the exception of Nigeria.[5]

### Cost of Future Power-Generation Options

Table 8 shows the assumptions on overnight investment costs for generic (*i.e.*, non-site specific) power generation in the base year. For non-renewable energy technologies, these are mainly based on the WAPP Master Plan, except for distributed diesel generators where parameters are sourced from the Energy Sector Management Assistance

[5] For Nigeria, generic hydro options are included after 2030. For other countries, data on total hydro resources were not available.

Table 6. Existing Power Generating Capacity (MW)

| Country | Oil | Coal | Gas | Hydro | Total |
|---|---|---|---|---|---|
| **Burkina Faso** | 146 | | | 23 | **169** |
| **Cote d'Ivoire** | | | 765 | 585 | **1,350** |
| **Gambia** | 49 | | | 0 | **49** |
| **Ghana** | 685 | | 180 | 1,044 | **1,909** |
| **Guinea** | 19 | | | 95 | **114** |
| **Guinea-Bissau** | 4 | | | 0 | **4** |
| **Liberia** | 13 | | | 0 | **13** |
| **Mali** | 114 | | 20 | 153 | **287** |
| **Niger** | 15 | 32 | 20 | 0 | **67** |
| **Nigeria** | | | 3,858 | 1,358 | **5,216** |
| **Senegal** | 395 | | 49 | 68 | **512** |
| **Sierra Leone** | 44 | | | 56 | **100** |
| **Togo/Benin** | 57 | | | 65 | **122** |
| **Total** | **1,541** | **32** | **4,892** | **3,447** | **9,912** |

Table 7. Capacity of Future Projects- MW (figures in parentheses refer to committed projects)

| Country | Oil | Coal | Gas | Hydro | Biomass | Wind | Solar | Total |
|---|---|---|---|---|---|---|---|---|
| **Burkina Faso** | 120 (112) | - | - | 60 | - | - | 40 | **220 (112)** |
| **Cote d'Ivoire** | - | - | 1,313 (863) | 1,072 | - | - | - | **2,385 (863)** |
| **Gambia** | 16 (16) | - | - | 68 | - | 1 (1) | - | **85 (17)** |
| **Ghana** | 100 | - | 2,265 (1,180) | 661 (228) | - | 150 (150) | 10 (10) | **3,186 (1,568)** |
| **Guinea** | 227 (227) | - | - | 3,346 (287) | - | - | - | **3,573 (514)** |
| **Guinea-Bissau** | 15 (15) | - | - | 14 | - | - | - | **29 (15)** |
| **Liberia** | 45 (45) | - | - | 967 (66) | 35 | - | - | **1,047 (111)** |
| **Mali** | 332 (166) | - | - | 434 (90) | 33 | - | 40 (10) | **839 (266)** |
| **Niger** | 32 (15) | 200 | 18 (8) | 279 (98) | - | 30 | 50 | **609 (121)** |
| **Nigeria** | - | - | 13,581 (8,531) | 3,300 | - | - | - | **16,881 (8,531)** |
| **Senegal** | 540 (180) | 1,000 (250) | - | 530 | 30 (30) | 225 | 8 | **2,333 (460)** |
| **Sierra Leone** | - | - | - | 755 | 115 | - | 5 | **875** |
| **Togo/Benin** | - | - | 630 (580) | 357 (147) | - | 20 | 35 | **1,042 (727)** |
| **Total** | **1,437 (776)** | **1,200 (250)** | **17,807 (11,162)** | **11,840 (916)** | **213 (30)** | **426 (151)** | **188 (20)** | **33,104 (13,305)** |

Program (2007). No cost reduction resulting from technology learning is assumed for non-renewable energy technologies in any scenario throughout the study period.

For renewable energy technologies, a reduction of overnight investment cost was assumed in the Renewable Promotion Scenario, as is presented in Figure 5. The learning rates anticipated are based on increased global installed capacity for those technologies. What is assumed here is more aggressive cost reduction, which would be achieved by governments and the private sector actively seeking opportunities: to increase local content; streamline regulations and taxation regimes; resolve bottlenecks in materials supply (including transportation problems and logistical constraints); achieve economies of scale, economic efficiency gains and so forth.

Assumptions on load factor, O&M costs, efficiency, construction duration and expected technology life for all generic technology options are given in Table 18, Appendix C. These are identical in all scenarios.

## Levelised Costs from Generic Options

LCOE was computed for the generic technology options available in the region based on the same assumptions (found in Table 18) on investment, O&M and fuel costs, capacity factor, generation capacity,and expected years of operation. For delivery of electricity using grids to different demand categories, additional T&D costs are added and T&D losses taken into account. This is detailed in Table 1 for the industrial, urban and rural demand categories.[6]

Figure 5. Overnight Investment Cost Assumptions for Renewable Energy Technologies in the Renewable Promotion Scenario

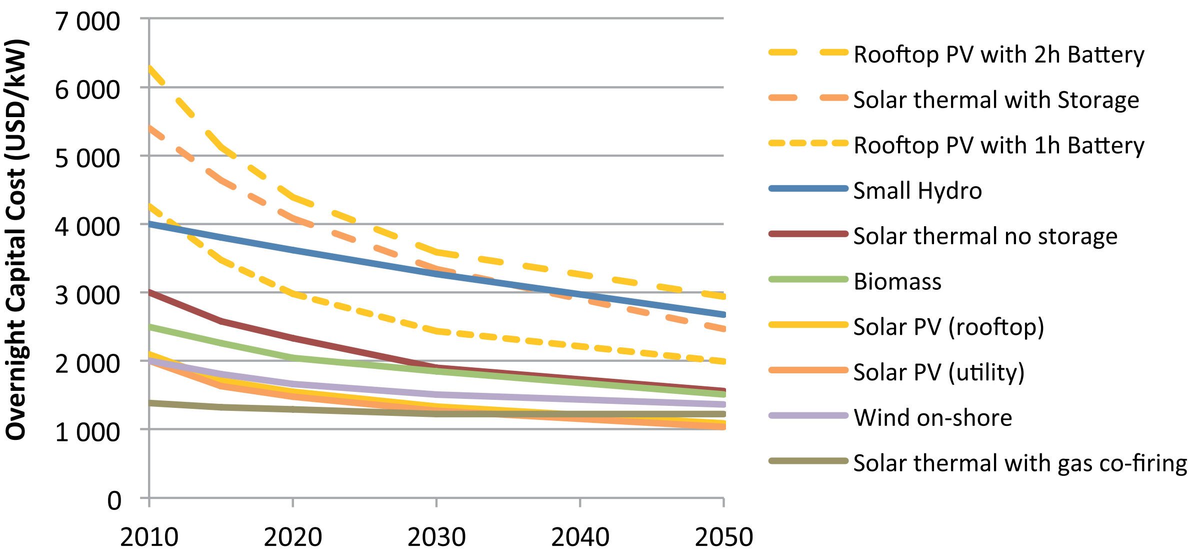


Table 8. Assumptions on Overnight Investment Costs for Generic Power Technologies

| Overnight Costs | | | |
|---|---|---|---|
| | USD/kW | | USD/kW |
| **Diesel/Gasoline 1 kW system (urban/rural)** | 692 | **Bulk wind (20% CF)** | 2,000 |
| **Diesel 100 kW system (industry)** | 659 | **Bulk wind (30% CF)** | 2,000 |
| **Diesel Centralised** | 1,070 | **Solar PV (utility)** | 2,000 |
| **HFO** | 1,350 | **Solar PV 1 kW (rooftop)** | 2,100 |
| **OCGT** | 603 | **PV with battery (1-hour storage)** | 4,258 |
| **CCGT** | 1,069 | **PV with battery (2-hour storage)** | 6,275 |
| **Supercritical coal** | 2,403 | **CSP no storage** | 3,000 |
| **Hydro** | 2,000 | **CSP with storage** | 5,400 |
| **Small hydro** | 4,000 | **CSP with gas co-firing** | 1,388 |
| **Biomass** | 2,500 | | |

[6] LCOE for the industry customer = LCOE of generation / (1-loss) + T&D costs of industry. For example, for diesel centralised, LCOE for the industry customer is: 291/(1-0.07)+15=328

The LCOEs of generic technology options considered in this analysis were computed for 2010, 2020, and 2030 based on assumptions for each of those years. These are presented in Table 9 for 2010 and 2030 for the Renewable Promotion Scenario. A more complete LCOE summary is given in Table 9, and in Appendix C, Tables 19-21.

Table 9 shows that in 2010, for the industrial demand category, which connects at high voltage, hydro is the cheapest option, followed by coal in countries that have domestic coal, and CCGT in countries with domestic gas. Imported coal and gas are the next cheapest options. In the Renewable Promotion Scenario, high capacity-factor wind overtakes domestic and imported coal and gas in 2020, as wind investment costs come down, and coal and gas prices rise. Biomass, where available, and utility PV also overtake imported coal and gas. CSP overtakes imported gas but not imported coal.

In 2030, utility PV and biomass overtake domestic coal and gas. CSP with no storage overtakes imported coal and gas (both imported and domestic).

For the urban demand category, in 2010, the rankings generic technology options in terms of LCOE are similar to those for heavy industry. Hydro is cheapest, followed by distributed or rooftop PV without batteries. PV with storage only starts to become interesting later in the modeling period. Rooftop PV with no storage overtakes hydro as the cheapest option on a levelised basis from 2020 onward.

Table 9. Levelised Cost of Electricity: Assumptions

| LCOE (USD/MWh) | Generation | | Industry | | Urban | | Rural | |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2030 | 2010 | 2030 | 2010 | 2030 | 2010 | 2030 |
| **Diesel centralised** | 291 | 339 | 328 | 376 | 433 | 440 | 516 | 552 |
| **Dist. diesel 100 kW** | 320 | 371 | 320 | 371 | | | | |
| **Dist. diesel/gasoline 1 kW** | 604 | 740 | | | 604 | 740 | 604 | 740 |
| **HFO** | 188 | 216 | 217 | 245 | 298 | 299 | 369 | 389 |
| **OCGT (domestic gas)** | 141 | 161 | 167 | 187 | 236 | 235 | 301 | 315 |
| **CCGT (imported gas/LNG)** | 111 | 126 | 134 | 150 | 196 | 195 | 258 | 269 |
| **CCGT (domestic gas)** | 90 | 102 | 112 | 124 | 168 | 167 | 229 | 236 |
| **Supercritical coal** | 101 | 106 | 124 | 127 | 183 | 172 | 244 | 241 |
| **Supercritical domestic coal** | 81 | 93 | 102 | 114 | 157 | 157 | 216 | 224 |
| **Hydro** | 62 | 62 | 82 | 81 | 132 | 122 | 189 | 183 |
| **Small hydro** | 107 | 89 | | | | | 107 | 89 |
| **Biomass** | 104 | 86 | 127 | 107 | 187 | 149 | 249 | 215 |
| **Bulk wind (20% capacity factor)** | 149 | 117 | 176 | 139 | 247 | 184 | 314 | 256 |
| **Bulk wind (30% capacity factor)** | 102 | 81 | 125 | 101 | 185 | 143 | 246 | 208 |
| **Solar PV (utility)** | 121 | 84 | 145 | 104 | 209 | 146 | 272 | 212 |
| **Solar PV 1 kW (rooftop)** | 143 | 96 | | | 143 | 96 | 143 | 96 |
| **PV with battery (1 hour storage)** | 250 | 151 | | | 250 | 151 | 250 | 151 |
| **PV with battery (2 hour storage)** | 323 | 192 | | | 323 | 192 | 323 | 192 |
| **CSP no storage** | 147 | 102 | 173 | 123 | 244 | 167 | 311 | 236 |
| **CSP with storage** | 177 | 116 | 205 | 139 | 282 | 184 | 352 | 255 |
| **CSP with gas co-firing** | 106 | 115 | 129 | 137 | 189 | 182 | 251 | 253 |

For the *rural demand* category, mini-hydro remains the best option where available. Distributed or rooftop PV without batteries is the next cheapest option, with storage options becoming competitive later in the modelling period.

The LCOE results shown here assume a load factor equal to the availability factor for each energy source. Note that the penetration of technologies is not solely based on LCOE; system requirements, in terms both of reliability, and of matching supply and demand, are also taken into account during optimisation. Also, given differences in investment and fuel costs, rankings would vary at different load factors. For example, gas plants at an 80% load factor may be less competitive than coal on a levelised basis, but more competitive at 40%. Diesel or Open Cycle Gas Turbines (OCGTs) would be competitive at very low load factors and could well play a role in meeting peak loads of short durations. The MESSAGE modelling framework takes account of this during optimisation, which is one of the reasons the results of optimisation can differ from what would be expected given the simple LCOE analysis.

For hydro power, neither generic technology options nor generic costs were used in the SPLAT-W model, although the typical LCOE for a hydro power plant is shown is the LCOE tables (19-21) in Appendix C, providing a reference indication of the cost competitiveness of hydro options. Figure 6 shows LCOE ranges for the 63 hydro projects that are included in the model as future options. Costs are highly site-dependent and can vary considerably from one plant to the next.

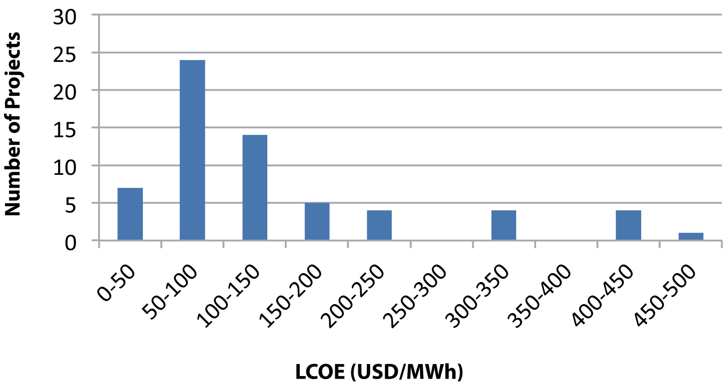


Figure 6. Levelised Cost of Electricity: Distribution of 63 Hydro Projects

Thorsten Schier©High voltage power lines with electricity pylons at twilight/Shutterstock

## 3.8 ASSUMPTIONS ON TRADE BETWEEN COUNTRIES

Trade between countries is limited by existing infrastructure and planned transmission projects. Any hypothetical project that is not currently identified is not included as an option. Existing transmission infrastructure and planned projects for transmission are based on the WAPP Master Plan (WAPP, 2011) and are summarised in Table 10 and in Table 11, with details in and Table 22 and Table 23 in Appendix D. In the case of Energy Security Scenario, each country's electricity imports are limited to 25% of electricity demand.

## 3.9 CONSTRAINTS RELATED TO SYSTEM AND UNIT OPERATION

In the SPLAT-W model, key system constraints are introduced to make sure the system is reliably operated.

### Reserve Margin

In order to increase the reliability of a power system, excess operational capacity needs to be installed over and above peak demand requirements. The reserve margin is defined as the difference between operable capacity and the peak demand for a particular year, as a percentage of peak demand. In all scenarios, a reserve-margin constraint of 10% has been imposed on every country. Only "firm" capacity, sure to be available at all times, is considered to contribute to this requirement.

The capacity credit, or the share of capacity that is considered "firm", equals 1.0 for dispatchable technologies, such as thermal and large hydro with dams. For variable renewable power technologies, however, the capacity credit depends on the share of total capacity and on the quality of the intermittent resource, including in terms having a range of sites with low correlation to each other. The capacity credit is generally lower than the availability factor, as no single site can be relied upon to generate power at any given time, considering the variability of wind and solar conditions.

The reserve margin constraint is defined as follows:

$$\sum_{i=1}^{n} \alpha(i) C_P(i) \geq (1 + RM) D$$

Where:

- $\alpha(i)$ is the capacity credit given to power plant/technology *(i)* or the share of capacity that is accounted as "firm" (fraction);
- $C_p(i)$ is the capacity of power plant/technology *(i)* in MW (centralised only);
- *D* is the peak demand on the centralised grid system in MW; and
- *RM* is the reserve margin (fraction).

### Constraints on Variable Renewables

Given that the model has an aggregate representation of the load, the variability of wind and solar PV was accounted for in an aggregate and conservative manner:

- The capacity of wind was de-rated by the availability factor (*i.e.*, a 100 MW wind plant with 30% capacity factor is constrained to only deliver 30 MW at any given point in time). The firm capacity for every megawatt of installed capacity was set to half the availability factor (in this example, 15%).
- Centralised PV plants and CSP were given a 5% and 30% capacity credit respectively.

When resources are spread over a large area, firm capacity may increase, as meteorological variability is dispersed, so that power generation is less affected by local meteorological conditions in any specific area. However, since the current study does not permit such detailed considerations, upper limits were set at 20% for the share of wind-generated electricity on the grid, and 10% for centralised PV. These limits were set conservatively, ensuring reliable system projections until the methodology is improved to allow more sophisticated modelling of intermittent supply options.

### Load following capability of power plants

There are some technical limitations as to how fast coal and biomass plants can ramp production up or down. To approximate this limitation, all coal and biomass plants in the model were de-rated by their availability factor. For example, a 100 MW coal plant with 85% availability can only produce up to 85 MW at any given point in time.

Run-of-river hydro power plants as well as mini-hydro options are modelled as non-dispatchable and thus also have their capacity de-rated by the availability

## Table 10. Existing Transmission Infrastructure Summary

| Country 1 | Country 2 | Line Capacity |
|---|---|---|
| | | MW |
| Ghana | Cote d'Ivoire | 327 |
| Ghana | Togo/Benin | 310 |
| Senegal | Mali | 100 |
| Cote d'Ivoire | Burkina Faso | 327 |
| Nigeria | Togo/Benin | 686 |
| Nigeria | Niger | 169 |

## Table 11. New Cross-Border Transmission Projects

| Project name | Approximate Line Capacity | Earliest year |
|---|---|---|
| | MW | |
| **Committed projects** | | |
| Dorsale 330 kV (Ghana, Togo/Benin, Cote d'Ivoire) | 650 | 2013 |
| CLSG (Cote d'Ivoire, Liberia, Sierra Leone) | 330 | 2014 |
| OMVG (Senegal, Guinea, Gambia, Guinea Bissau) | 315 | 2017 |
| Hub Intrazonal (Ghana, Burkina Faso, Mali, Cote d'Ivoire, Guinea) | 320 | 2014-2020 |
| | | |
| **Planned projects** | | |
| Corridor Nord (Nigeria, Niger, Togo/Benin, Burkina Faso) | 650 | 2014 |
| | | |
| **Other projects** | | |
| Dorsale Mediane (Nigeria, Togo/Benin, Ghana) | 650 | 2020 |
| OMVS (Mali, Senegal) | 330 | 2020 |

Warren Gretz©Harvesting corn and stover/NREL factor. Hydro power plants with dams are modelled as dispatchable to reflect the more flexible operation that a dam allows. A "dry-year" assumption also defines their availability factor for all hydro options.

Finally, the dispatch patterns modelled for three types of solar rooftop PV system are illustrated in Figure 7, which shows the output for 1 MW of installed rooftop solar PV.

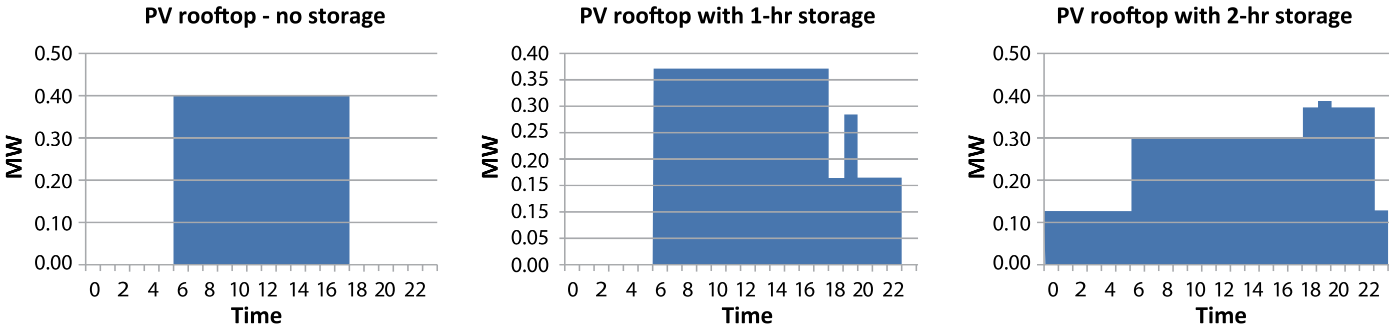


Figure 7. Diurnal Variation of Solar Photovoltaic Output

Dennis Schroeder©Installing mirrored parabolic trough collectors/NREL

# 4. Modelling Results

## 4.1 REFERENCE SCENARIO

The Reference Scenario is calibrated to the reference scenario of the WAPP Master Plan, which is based on a number of conservative assumptions on renewable deployment costs.

This study's Reference Scenario was set up mainly to demonstrate the compatibility of the SPLAT-W tool with the tool used for WAPP Master Plan development.

As expected, the results are consistent with those presented in the reference scenario of the WAPP Master Plan. Figure 8 presents the electricity generation mix in the Reference Scenario.

The main difference between the SPLAT-W results and the WAPP Master Plan is the lower share of hydro in the SPLAT-W model due to the "dry-year" assumption imposed over the entire modelling period.

Notably, SPLAT-W fills current supply-demand gaps with on-site diesel generators. As more power-supply options become available, these gaps are quickly filled and replaced by grid-supply electricity or on-site renewable energy technology options, mainly from mini-hydro.

The share of hydropower increases from 18% to 34% of total electricity generation (or from 22% to 29% of grid-connected electricity) by 2030, while the share of other renewables remains small, at 5%, with most of it coming from biomass.

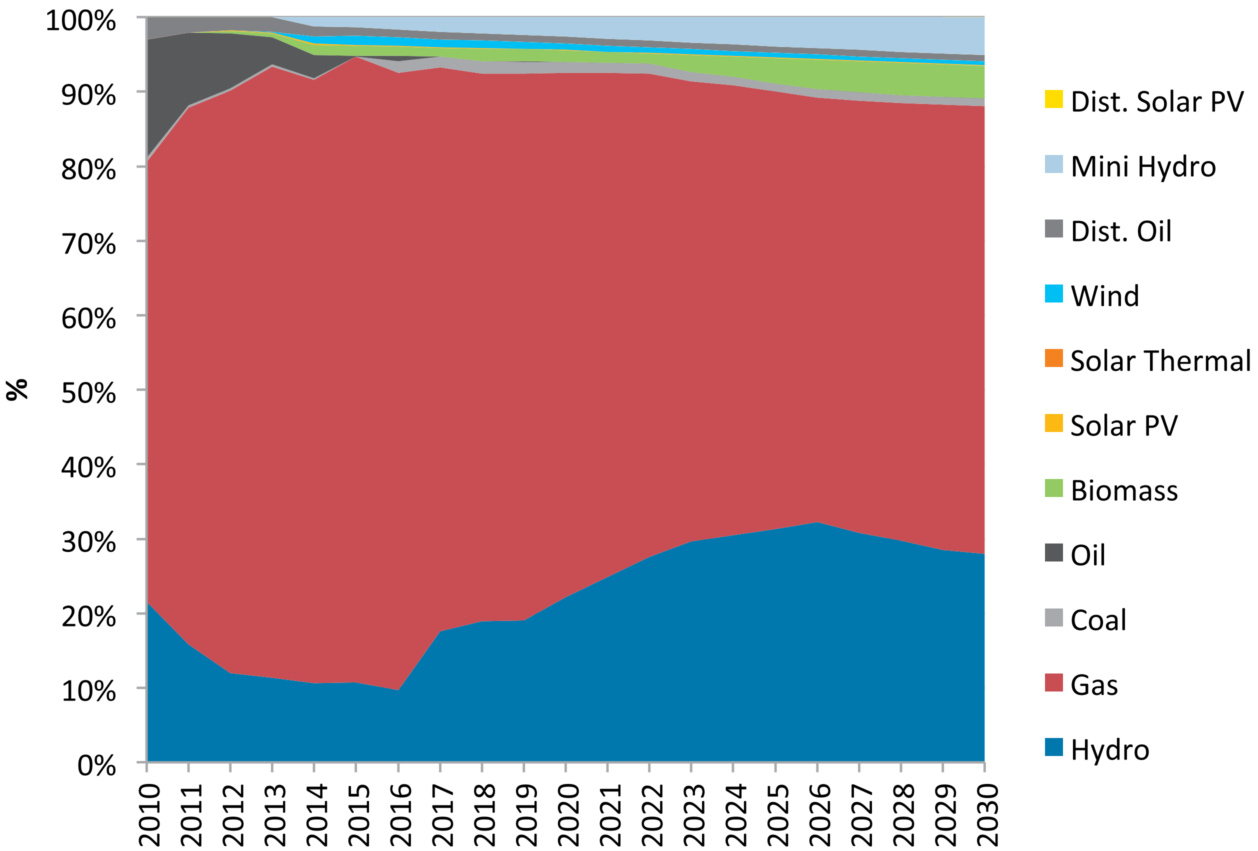


Figure 8. Electricity Production in the Reference Scenario

## 4.2 RENEWABLE PROMOTION SCENARIO: INVESTMENT AND GENERATION MIX THROUGH 2030

In WAPP countries, electricity demand is expected to increase nearly six times by 2020 and 14 times by 2050. Installed, grid-connected capacity in 2010 was estimated to be about 9.4 gigawatts (GW), out of which more than half was fuelled with gas, 33% was hydro based, and the remainder was mainly fuelled with oil.

Current grid-connected capacity is not sufficient to cover the demand, and over 1 GW of decentralised diesel generator is installed to meet the deficiency.

Figure 9 shows the retirement schedule of the existing capacity. By 2030, half the existing capacity will be retired.

In order to meet the growing demand, over 60 GW of additional capacity is needed by 2030 in the Renewable Promotion Scenario.

Figure 10 shows the investment schedule in the Renewable Promotion Scenario. Appendix E shows all the projects 'selected' in this scenario. Out of 23 GW of gas deployed in the first decade, some 11 GW comes from already-committed projects. In the case of hydro power, some 16 GW is deployed up to 2030, nearly half in the first decade (2010-2020) and the remainder in the second. Distributed diesel generators continue to be deployed, mainly in the industrial demand category. Deployment of renewable technologies other than large hydro exceeds 13 GW by 2030.

Table 12 shows capacity additions during 2010-2030 by country, for centralised and decentralised power

Solar Panels in West Africa (ECREEE)

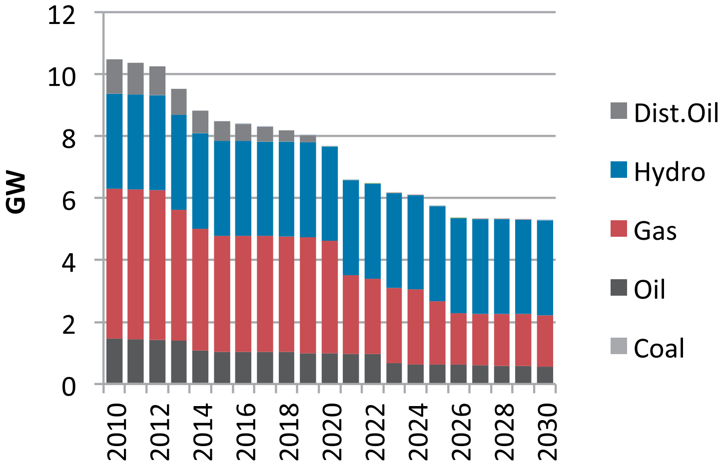


Figure 9. Energy Capacity Mix of Existing Plans

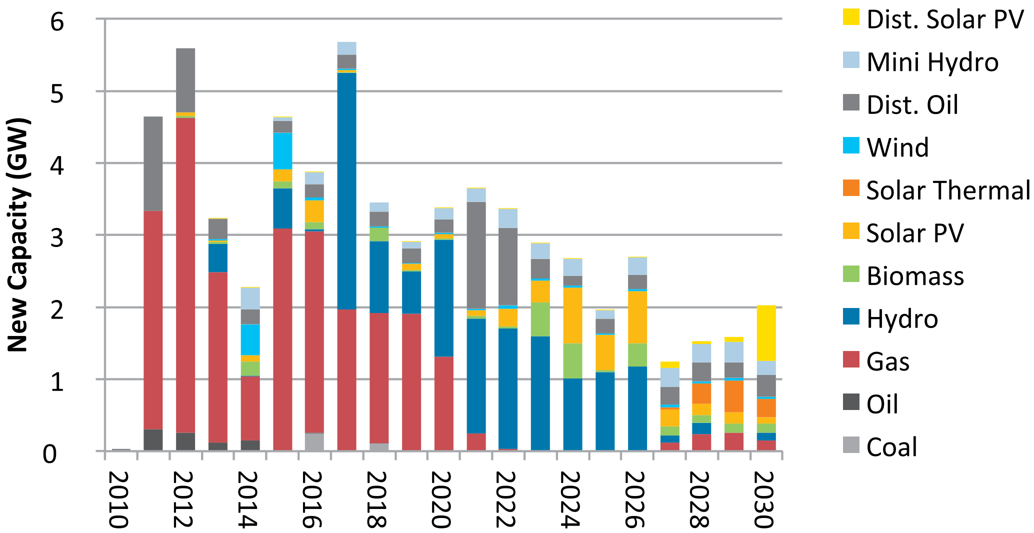


Figure 10. New Capacity Addition under the Renewable Promotion Scenario until 2030

| MW | Centralised | | Decentralised | |
|---|---|---|---|---|
| | Total | Renewable | Total | Renewable |
| Burkina Faso | 800 | 688 | 258 | 121 |
| Cote d'Ivoire | 3,543 | 962 | 702 | 152 |
| Gambia | 254 | 179 | 91 | 36 |
| Ghana | 5,182 | 2,928 | 2,177 | 896 |
| Guinea | 3,842 | 3,615 | 244 | 120 |
| Guinea-Bissau | 294 | 145 | 62 | 17 |
| Liberia | 560 | 402 | 78 | 46 |
| Mali | 890 | 682 | 162 | 72 |
| Niger | 645 | 469 | 130 | 47 |
| Nigeria | 29,057 | 10,504 | 7,506 | 2,568 |
| Senegal | 2,299 | 1,869 | 471 | 104 |
| Sierra Leone | 1,418 | 1,185 | 258 | 120 |
| Togo/Benin | 1,919 | 1,296 | 500 | 90 |
| **Total** | **50,704** | **24,924** | **12,640** | **4,389** |

Table 12. Capacity Addition by Country, 2010-2030: Renewable Promotion Scenario

generation. Out of total capacity addition of 63 GW, renewable energy technologies accounts for 46%.

As a result of these new investments, the share of renewables in total generation capacity increases from 29% (only hydro) to 51% (or 30% hydro, 21% other renewables) by 2030. This goes beyond the targets defined by the ECOWAS Renewable Energy Policy, in which renewable-based power generation capacity by 2030 would be 48% of the total. Figure 11 shows the development of capacity balance in the region under the Renewable Promotion Scenario.

The implication of these investments on the electricity supply mix under the Renewable Promotion Scenario is shown in Figure 12. Note that this figure includes electricity supply from the Central Africa region (shown as 'Net Imports'). The general trend is the replacement of gas-based generation with more hydro and imported power.

Looking at the electricity supply mix in 2010-2030, the share of large hydropower increases from 22% to 41% (counting imports from Central Africa as large hydro). Other renewables would add 17% during the period, which makes for a 58% total share of renewables in the region's total electricity *supply* by 2030. Strictly in terms of the *generation* mix (*i.e.*, not counting imports), the share of renewables in the *generation* mix increases from 22% in 2010 to 52% (33% hydro; 19% other) in 2030.

The share of renewables in grid-connected generation is 48%, of which hydro alone accounts for 35 percentage points. In the ECOWAS Renewable Energy Policy, the regional target is 31% renewables in total grid-connected generation by 2030. The Renewable Promotion Scenario, more optimistically,[7] sees this target being achieved by the early 2020s.

Decentralised electricity supply options account for 7% of total electricity supply in 2030, with major part of these being based on renewable sources.

The overall picture is, to a large extent, dominated by developments in Nigeria and Ghana, which account for about 60% and 10% of total regional electricity demand, respectively. Figure 13 shows the generation mix in 2010 and 2030 in each country in the Renewable Promotion Scenario. In 2010, electricity is produced mainly from gas, oil or hydropower. Some countries have very high import shares. In this scenario, electricity production is more diversified in all countries by 2030.

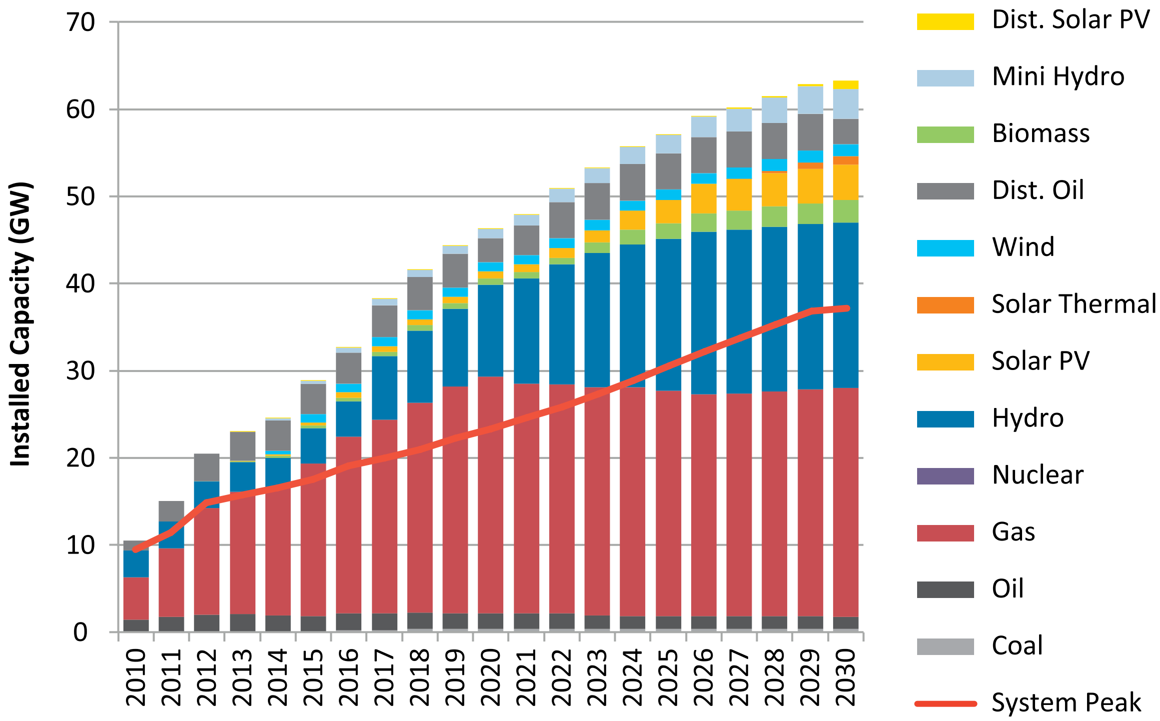


Figure 11. Capacity Balance under the Renewable Promotion Scenario

[7] When comparing our results against the ECOWAS Renewable Energy Policy in terms of the share of renewables based on installed capacity by 2030, the difference was much smaller (51% in our scenario and 49% in the ECOWAS policy). This is mainly explained by the fact that in our technology portfolio, we explicitly took into account decentralised diesel generation, whose share of capacity is large in comparison to actual generation.

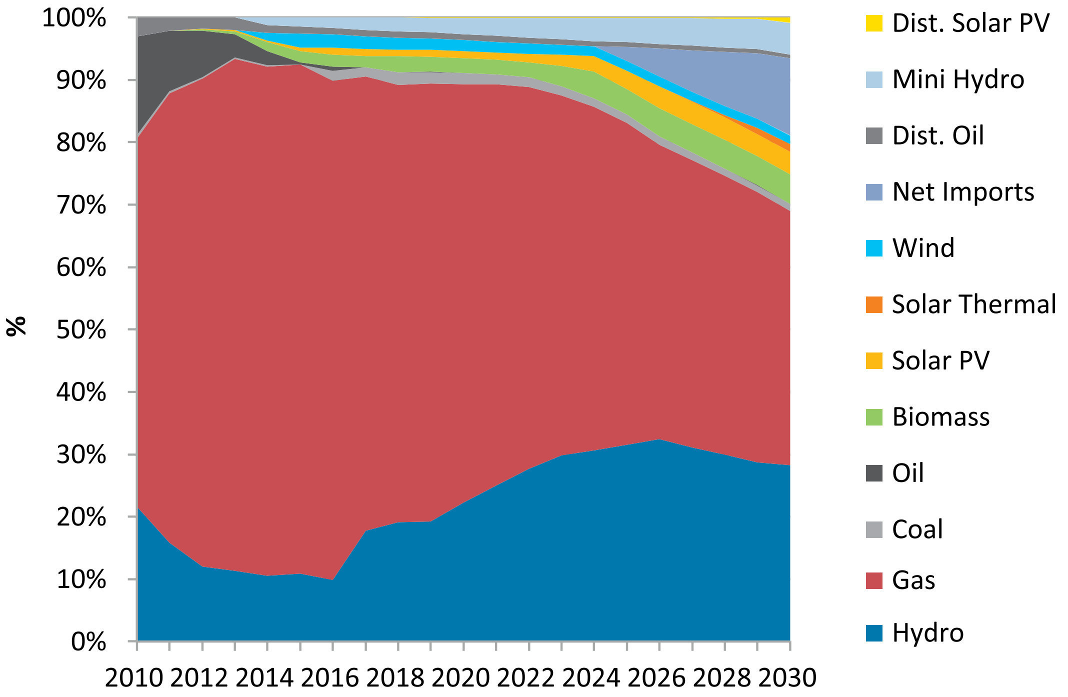


Figure 12. Electricity Supply in the Renewable Promotion Scenario: Regional Generation plus Imports from Central Africa

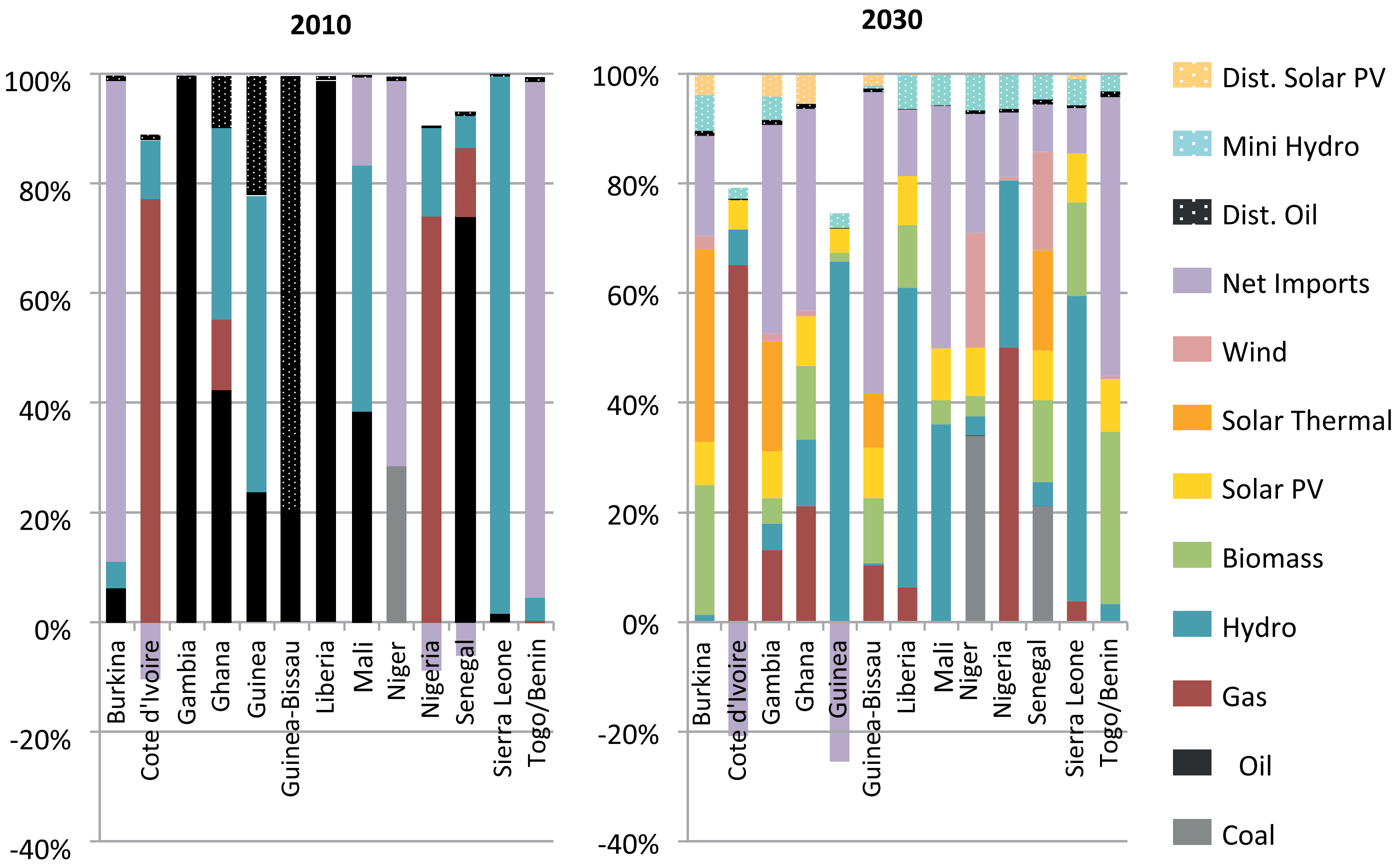


Figure 13. Electricity Production Shares by Country in 2010 and 2030 under the Renewable Promotion Scenario

The share of renewables in the regional electricity supply by 2030 in the Renewable Promotion Scenario is 52%, but this varies on a country-by-country basis, with far higher penetration being economically favourable in some countries. Hydro plays a major role In Cote d'Ivoire, Guinea Bissau, Liberia, Nigeria and Sierra Leone, while total renewable energy penetration virtually reaches 100% by 2030 in Burkina Faso, Guinea and Mali.

Solar PV, wind, and biomass-based electricity generation do not have high shares in the overall regional electricity generation mix, but on a country-by-country basis, these technologies become an important part of the electricity generation portfolio in some countries. For example, these three technologies together account for more than 90% of domestically produced, grid-connected electricity in Burkina Faso and Togo/Benin.[8] More than 60% is accounted for in Gambia, Guinea-Bissau and Senegal.

Figure 14 shows regional energy trade flows in 2030 under the Renewable Promotion Scenario. It shows that the main flows are from Democratic Republic of Congo (DRC) and Cameroon to Nigeria, with some of this power exported on to Ghana, via Togo/Benin, or to Niger. There are also export flows from Guinea to surrounding countries: Guinea-Bissau, Mali, Senegal and Sierra Leone, as well as to Cote d'Ivoire via Liberia. Cote d'Ivoire itself exports to Mali, Burkina Faso and Ghana.

Figure 15 shows the share of urban and rural electricity demand met by distributed generation in 2030 under the Renewable Promotion Scenario. In the urban demand category, most of this distributed generation comes in the form of rooftop PV with battery, along with some diesel generation. In the rural demand category, distributed generation comes from mini-hydro when available, with the remainder being met through a mix of diesel generators and rooftop PV with battery.

ZSM©Akosombo Dam is spilling water, Ghana/Wikimedia

[8] However, the share of domestic generation in total domestic system demand is relatively small, 19% for Burkina Faso and 30% and Gambia, as the results include a high share of electricity imports.

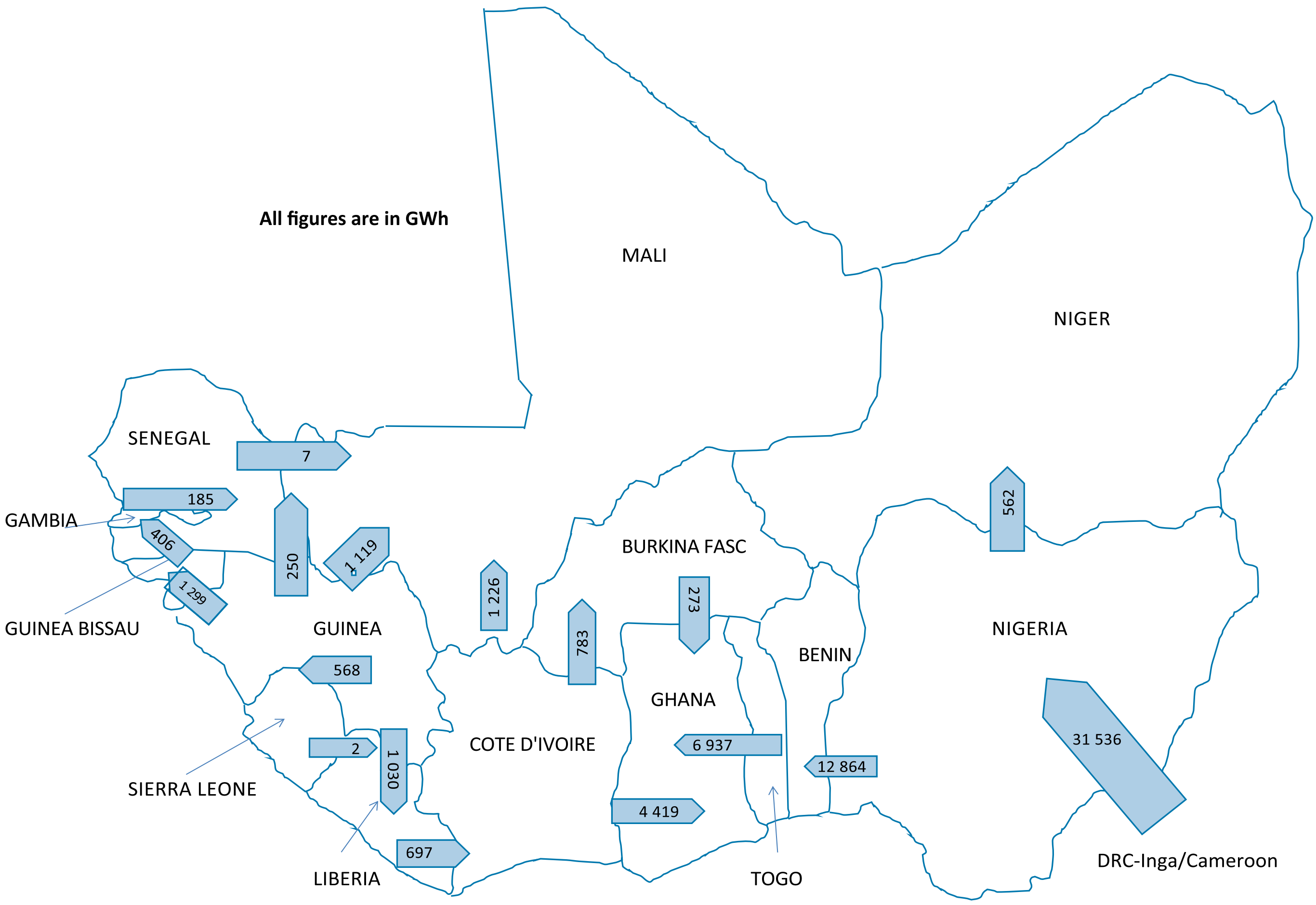


Figure 14. Regional Trade in 2030 in the Renewable Promortion Scenario

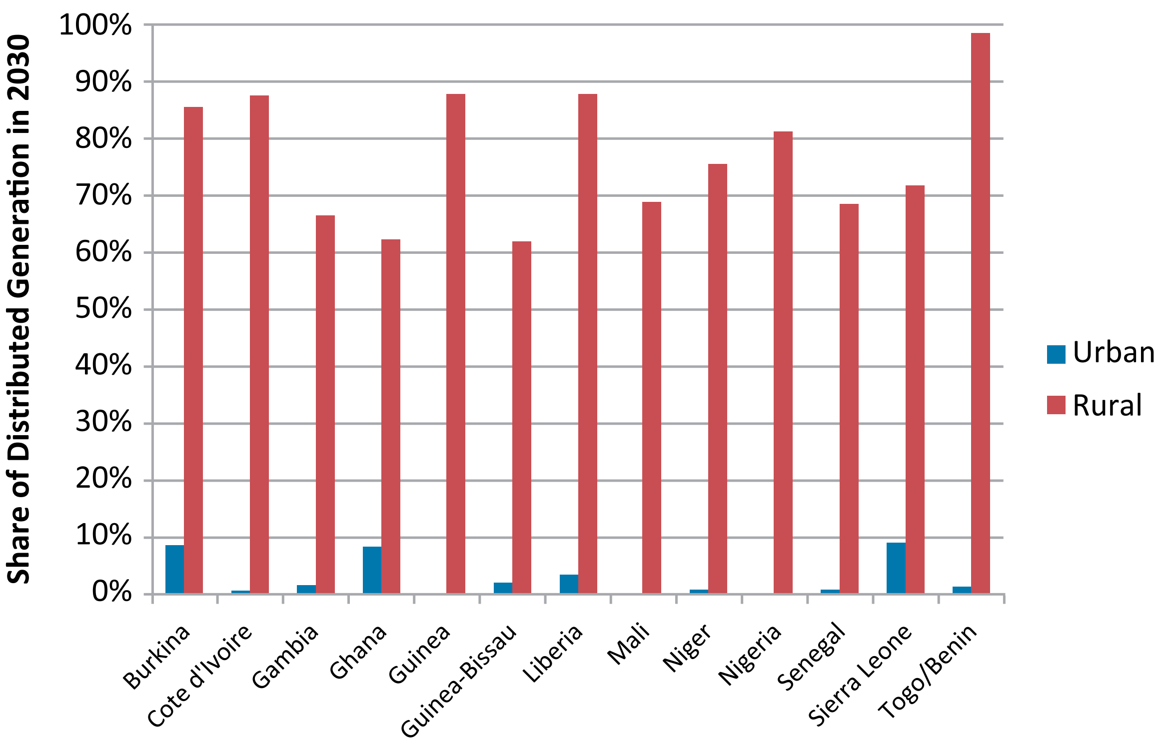


Figure 15. Share of Distributed Generation in Urban and Rural Demand in 2030 for the Renewable Promotion Scenario

## 4.3 ECONOMIC IMPLICATIONS OF THE RENEWABLE PROMOTION SCENARIO

The SPLAT-W model computes the economic implications of a given scenario in terms of investment (for generation and T&D), fuel and O&M costs, along with gains from carbon finance. The sum of these cost elements constitutes the system cost, which the model tries to minimise.

Figure 16 shows the undiscounted system costs for selected years in the Renewable Promotion Scenario. Investment costs substantially grow to meet growing electricity demand. Overall investment needs in the region between 2010 and 2030 amount to USD 170 billion (undiscounted) or USD 47 billion (discounted). This includes domestic T&D costs and cross-border transmission lines, which add up to about 37% of total investment costs. The average cost of electricity would drop slightly, from USD 0.14/kWh in 2010 to USD 0.13/kWh by 2030, mainly reflecting reduced reliance on expensive liquid fuels for power generation.

Although significant at the beginning of the modelling period, they are replaced first by hydro and then by a combination of coal, gas, renewables (including hydro), and imports from Central Africa. This is in contrast to our analysis of the Southern African Power Pool (SAPP), where a similiar renewable promotion scenario suggests an increase in average electricity costs (IRENA, 2013b). This is because SAPP countries currently rely on cheaper coal and hydro, but are expected to shift to more expensive low-$CO_2$ options, mainly to meet the emission reduction aspirations of South Africa. By 2030, however, average electricity costs in both regions look very similar.

## 4.4 COMPARISON WITH ALTERNATIVE SCENARIOS

The Renewable Promotion Scenario explores how much renewable energy technologies could contribute to the least-cost solution under favourable conditions. These conditions include the reduction of renewable energy technology investment costs, escalation of fossil-fuel prices, and electricity imports from the Central African region providing access to its rich hydro resources. Figure 17 shows electricity supply shares under the Renewable Promotion Scenario and the two alternative renewable scenarios, namely, the No Central Africa Import Scenario and the Energy Security Scenario.

In the Renewable Promotion Scenario, imports from Central Africa are included as an option after 2025. When imports from Central Africa are not allowed, the needed electricity is provided by solar PV and biomass.

In the Energy Security Scenario, where electricity import shares are limited to 25% by 2030, the overall regional result shown in Figure 17 does not change greatly, as the counties most affected by this new constraint are relatively small ones. Country-by-country results are shown in Figure 18. The reduction of imports in electricity supply is offset mainly by the deployment of solar technologies.

The average cost of electricity generation decreases from USD 139 per megawatt-hour (MWh) to USD 128 per MWh by 2030 in the Renewable Promotion Scenario, but only to USD 132 per MWh in the No Central Africa Import Scenario, implying that inter-regional electricity trade could reduce West Africa's average generation costs in 2030 by 3%.

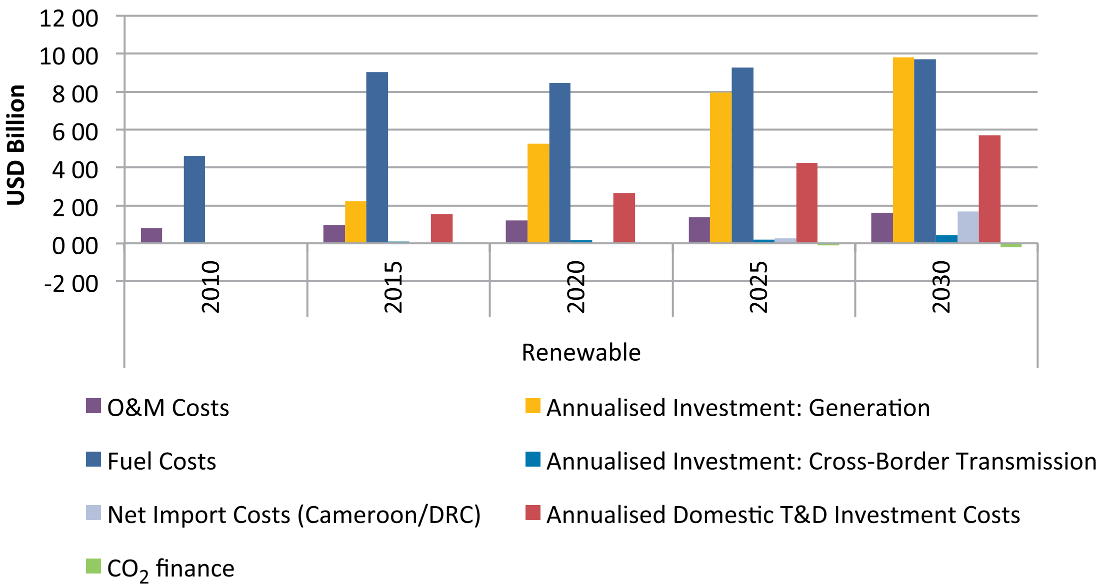


Figure 16. Annualised Undiscounted System Costs in the Renewable Promotion Scenario

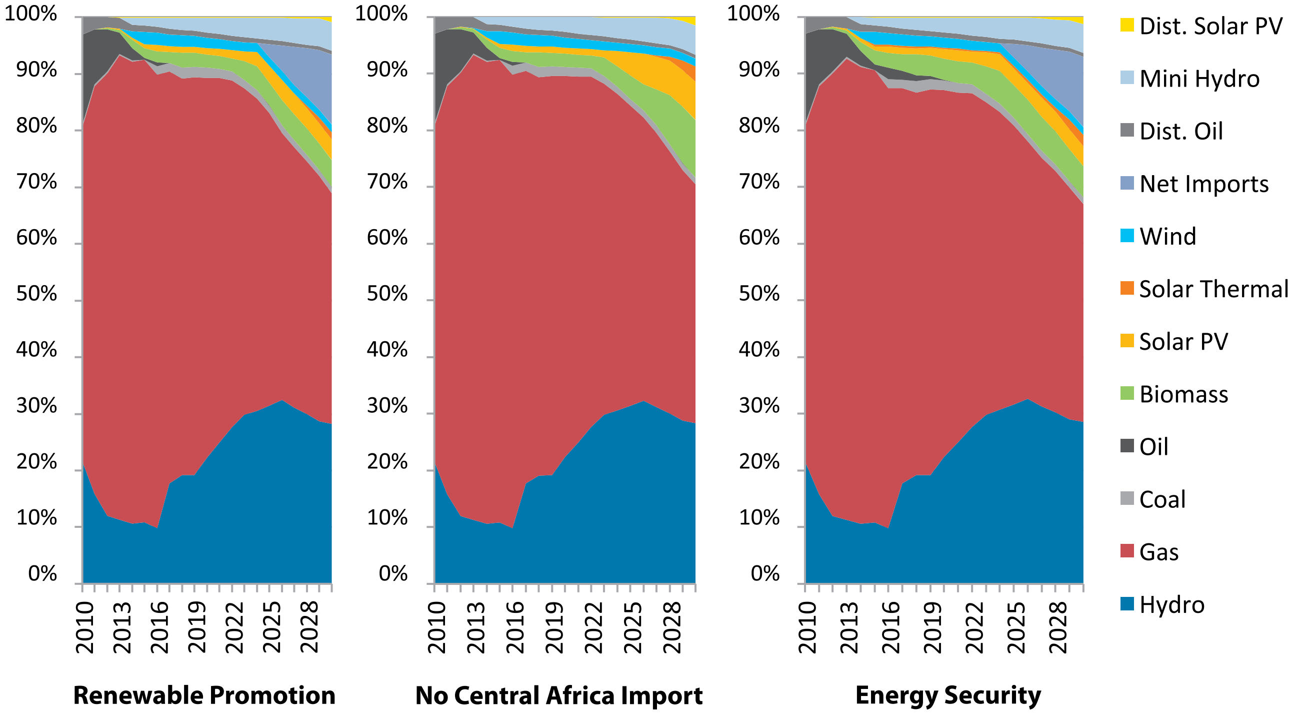


Figure 17. Electricity Supply Shares under Three Alternative Scenarios

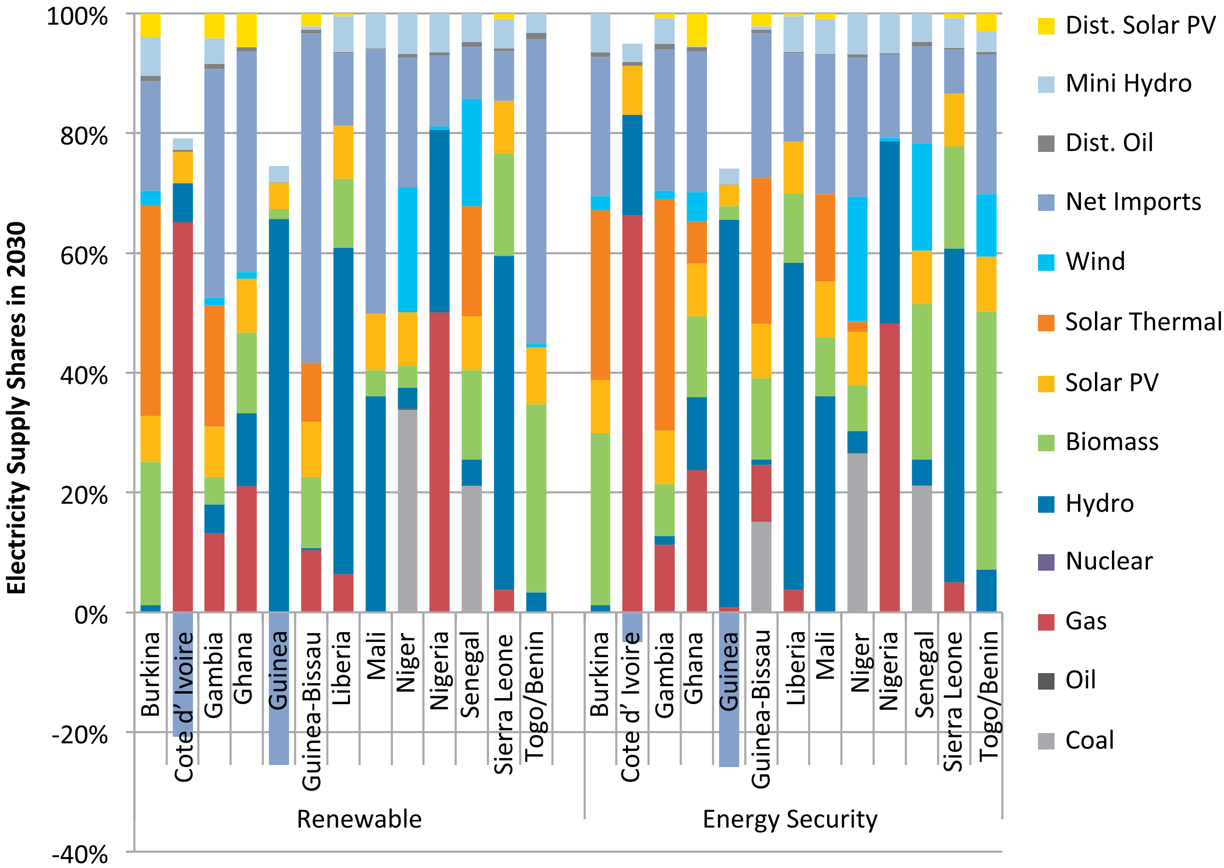


Figure 18. Electricity Supply Mix by Country: Renewable Promotion Scenario *vs.* Energy Security Scenario

Steve Heap©Water falling 1600 feet down Wli Waterfall near Hohoe in Ghana/Shutterstock

# 5. Long-term Energy Planning and Integration of Renewable Energy in Power Systems

The SPLAT-W model used in this analysis was developed primarily with the aim of helping IRENA member countries to take ownership of the process of developing long-term renewable integration scenarios and strategies, by transferring these to interested countries' energy planning offices. In developing such long-term scenarios and strategies, a formal power-system modelling technique, as shown in this report, could play an important role for two main reasons.

Firstly, it provides a rational basis for decision-making. A formal modelling technique assesses overall investment needs to meet demand and helps to prioritise alternative investment options based on economic criteria, *i.e.*, cost minimisation. It also takes account of other considerations, including social ones (import dependency, reliability of supply, rural electrification, etc.) and environmental ones (emissions of air pollutants and greenhouse gas, etc.). This allows various "what-if" analyses to compare the implications of different policy options.

Secondly, the processes for developing long-term scenarios using a formal modelling technique provide a platform for consensus-making among stakeholders who may have conflicting objectives. The advantage of using a model is that different objectives can be traded-off while avoiding inconsistencies.

Analytical work using formal modelling tools is a basic "must" in putting forward a long-term vision of energy sector development. Electricity master plans are typically developed based on fully fledged electricity sector analysis using such modelling tools. However, in many African countries, the local capacity to obtain or use such tools is often limited.

The process of planning is as important as the plan itself, so the local capacity to use energy modelling tools is important. Moreover, local capacity allows timely updates to a plan, which can often be a problem when relying on analysis by foreign consultancy firms. The landscape surrounding the power sector, and in particular renewable technologies, is rapidly changing, and modelling tools allow these changes to be addressed.

Another advantage of owning the energy planning process is that it allows possible caveats in the use of energy planning tools to be fully appreciated. Any model output must be considered in light of input data, model structure and modelling framework limitations.

It is against this background that IRENA developed the SPLAT-W model. Special attention has been given to the representation of renewable power-supply options and their integration into the power system. The aim is to make the SPLAT-W model available to interested energy planners and academics in the region, so that they can use it to explore alternative scenarios for national and regional power sector development. The SPLAT-W model provides links to IRENA's latest resource and technology cost assessments. It is configured with information in the public domain and can be easily updated by country experts in the region with the latest information that may not be in public domain.

The purpose of this analysis is not to develop or advocate a renewable transition plan for the region. Rather, the scenarios presented here are intended to provide a suitable starting point for analysts around the region to engage in further discussions. Along with highlighting the initial assumptions and results, the aim is to eventually transfer the model for local experts to use for energy planning purposes. Further scenarios can be created for specific policy assessments. Energy planning is a continuous process, and modelling tools for decision-making need to be kept alive by constant revision as new information is received.

In December 2012, IRENA, in cooperation with ECREEE, organised a workshop to discuss the role of planning in energy-sector development and renewable energy promotion; to present IRENA's SPLAT-W model; and

John Copland©Palm tree dates/Shutterstock

to identify areas of collaboration in the field. Invited participants from ECOWAS countries, representing energy planning offices in the region's governments and utilities, acknowledged that having access to planning tools such as the SPLAT-W model was important, although access to such tools and the capacity to use them was limited in some countries.

The countries of the region, following the adoption of the ECOWAS Renewable Energy Policy in October 2012, are developing national renewable deployment plans, making the availability of SPLAT-W timely. With National Renewable Energy Action Plans to be developed over the next two years, the SPLAT-W model is seen as an appropriate tool to support this process. IRENA, together with its partner organisations, has been planning the formation of a capacity-building support framework for this region-wide undertaking.

Jojje©The Earth on white background/Shutterstock

# 6. Conclusions

The SPLAT-W model was developed to provide decision makers and analysts from IRENA member countries in the West African region with a planning tool to help design medium- to long-term power systems, prioritise investment options, and assess the economic implications of a given investment path.

More specifically, SPLAT-W allows analysts to design an energy system that meets various system requirements (including reliability), while taking into account investment and operation costs to meet daily/seasonally fluctuating demand.

To summarise, the key features of the SPLAT-W model are as follows:

- The latest WAPP Master Plan for electricity production and transmission (WAPP, 2011) outlines: projected electricity demand; data on existing generation and cross-border transmission infrastructure; and planned or proposed projects in the West African region for additional generation capacity and cross-border transmission lines.
- Demand for electricity is split into three categories: heavy industry; urban residential, commercial and small industries; and rural residential and commercial. This also allows a better representation of decentralised power supply and improves the representation of the load curve.
- Three demand categories are modelled to require different levels of T&D infrastructure and incur different levels of electricity losses. Each demand category implies access to a different mix of distributed generation options.
- The cost and performance evolution of renewable energy technologies is taken from the latest IRENA study (IRENA, 2013a).
- Renewable energy potential follows IRENA's latest resource assessment studies (IRENA, 2013b).
- The nuclear option was excluded from the analysis, as it requires further investigation into technical, legal and economic challenges, and is outside the scope of this study.

The results presented here should serve as a basis for further discussion. The methodology will be used as a framework for further refinement of general assumptions to reflect the perspectives of energy planners in the various countries of the region.

Four scenarios were developed using SPLAT-W: Reference, Renewable Promotion, and two variants of Renewable Promotion. These have provided a basis for further analysis and possible elaboration.

- The Reference Scenario was configured with consistent assumptions, as used in the WAPP Master Plan, including: international power trade; no reduction in cost with renewable energy technologies; and constant fossil-fuel costs.
- The Renewable Promotion Scenario forsees international and inter-regional (*i.e.*, from Central Africa) power trade, modest cost escalation for fossil fuels, and cost reductions for renewable energy.
- The No Central Africa Imports Scenario excludes electricity imports from Central Africa (DRC/Cameroon)
- The Energy Security Scenario limits imports to 25% of each country's electricity by 2030.

The Reference Scenario was developed mainly to benchmark the SPLAT-W model against the WAPP Master Plan. The focus of our analysis was on the Renewable Promotion Scenario and its variants.

The share of renewable energy in power generation around the region was 22% in 2010. In the Renewable Promotion Scenario, this rises to 56% by 2030. Given a nearly five-fold increase of electricity demand over this period, renewable power generation grows more than ten-fold in absolute terms. The overall contribution of renewables to power generation ranges from around 22% in Cote d'Ivoire to 100% in Burkina Faso, Guinea and Mali. Three-quarters of this renewable power supply in 2030 originates through hydropower generation within the ECOWAS region, which is supplemented by imported hydropower from Central Africa. In the Renewable Promotion Scenario, renewables could greatly help to increase access to electricity in rural areas.

The total capacity additions needed to meet demand over the period of 2010-2030 are calculated as 68 GW, of which one-third are decentralised options. Renewable energy technologies account for 48% of total capacity additions in the Renewable Promotion Scenario. In the No Central Africa Import Scenario the share rises to 56%, while remaining at 55% in the Energy Security Scenario. In all three variants of the Renewable Promotion Scenario, decentralised options play an important role, especially in rural areas.

The investment needed between 2010 and 2030 in the Renewable Promotion Scenario is USD 55 billion (discounted). As discussed in IRENA (2011b), adequate electricity provision has been a challenge for the African continent. Reliable, affordable, low-cost power supply is needed for economic growth, and renewable energy can play an important role in filling this gap. In particular, African countries are in the enviable position of being able to choose their future energy pathway. The Renewable Promotion Scenario assumes relatively rapid reduction of renewable investment costs. Whether this is feasible depends on the level of policy and private sector engagement. The policy framework is crucial for successful renewable energy development.

This report presents a quantitative analysis of the Renewable Promotion Scenario, in which all these opportunities are realised through the engagement of governments. The model demonstrates the valuable role that renewable energy can play in meeting growing electricity demand in the region. Country-level analysis takes into account each country's particularities in terms of composition of demand and available resources. The model also considers regional factors and identifies opportunities for trade that would benefit both resource-rich and resource-poor countries.

The assessment presented here is based on certain key assumptions, including fuel costs, infrastructure and policy developments, which were taken from the WAPP Master Plan. Energy planners in ECOWAS countries may question some of these key assumptions, and any country may produce updated information. Any assessment is strongly influenced by its initial assumptions. IRENA, therefore, encourages energy planners to explore different policy assumptions and scenarios, as these can help to justify or articulate the challenges associated with investment decisions.

IRENA and ECREEE initiated a data validation process involving local experts, as well as implementing enhancements of modelling methodology. Modelling enhancements include: detailed analysis of land-use exclusion zones when assessing renewable energy potential; differentiation between countries in terms of capacity factors for solar and wind technologies; and better representation of investments in domestic transmission lines associated with higher shares of solar and wind technologies.

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Africa924©Typical village to the south of Senegal/Shutterstock


Sierra Pacific©Geothermal plant

# Appendix A: Detailed Demand Data

Table 13. Final Electricity Demand Projections (GWh)

| | Senegal | Gambia | Guinée Bissau | Guinea | Sierra Leone | Liberia | Mali | Ivory Coast | Ghana | Togo/ Benin | Burkina | Niger | Nigeria | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2010** | 2,494 | 219 | 141 | 608 | 162 | 34 | 1,098 | 5,814 | 9,022 | 2,083 | 859 | 835 | 23,179 | 47,554 |
| **2011** | 2,654 | 239 | 141 | 608 | 552 | 47 | 1,136 | 6,005 | 11,107 | 2,383 | 873 | 849 | 39,102 | 65,696 |
| **2012** | 2,991 | 337 | 149 | 760 | 617 | 138 | 1,232 | 6,390 | 11,735 | 2,763 | 934 | 912 | 58,069 | 87,027 |
| **2013** | 3,147 | 414 | 157 | 934 | 994 | 294 | 1,382 | 6,799 | 13,064 | 3,004 | 1,006 | 977 | 61,321 | 93,493 |
| **2014** | 3,319 | 496 | 167 | 1,102 | 1,397 | 883 | 2,111 | 7,245 | 13,735 | 3,268 | 1,087 | 1,044 | 64,964 | 100,818 |
| **2015** | 3,744 | 586 | 176 | 1,563 | 1,498 | 1,446 | 2,226 | 7,731 | 14,455 | 3,547 | 1,173 | 1,235 | 68,830 | 108,210 |
| **2016** | 4,311 | 747 | 538 | 4,361 | 2,327 | 2,119 | 2,896 | 8,197 | 15,223 | 3,841 | 1,265 | 1,306 | 72,926 | 120,057 |
| **2017** | 4,536 | 771 | 584 | 4,448 | 3,102 | 2,136 | 2,997 | 8,680 | 16,041 | 4,151 | 1,362 | 1,379 | 77,258 | 127,445 |
| **2018** | 4,774 | 796 | 632 | 4,542 | 3,841 | 2,154 | 3,153 | 9,182 | 16,912 | 4,478 | 1,466 | 1,454 | 81,856 | 135,240 |
| **2019** | 5,026 | 821 | 683 | 6,739 | 5,003 | 2,174 | 3,248 | 9,703 | 17,840 | 4,822 | 1,576 | 1,530 | 86,717 | 145,882 |
| **2020** | 5,306 | 847 | 1,086 | 6,873 | 6,163 | 2,195 | 3,398 | 10,244 | 18,828 | 5,185 | 1,694 | 1,609 | 91,873 | 155,301 |
| **2021** | 5,624 | 879 | 1,142 | 7,043 | 6,213 | 2,218 | 3,567 | 10,807 | 19,879 | 5,567 | 1,820 | 1,691 | 98,732 | 165,182 |
| **2022** | 5,933 | 912 | 1,166 | 7,187 | 6,263 | 2,242 | 3,740 | 11,391 | 20,998 | 5,971 | 1,953 | 1,774 | 104,604 | 174,134 |
| **2023** | 6,261 | 945 | 1,192 | 7,332 | 6,313 | 2,268 | 3,916 | 11,998 | 22,189 | 6,395 | 2,095 | 1,860 | 110,821 | 183,585 |
| **2024** | 6,611 | 980 | 1,218 | 7,477 | 6,363 | 2,295 | 4,097 | 12,628 | 23,456 | 6,842 | 2,247 | 1,948 | 117,412 | 193,574 |
| **2025** | 6,983 | 1,017 | 1,246 | 7,626 | 6,413 | 2,324 | 4,282 | 13,284 | 24,803 | 7,314 | 2,408 | 2,039 | 124,393 | 204,132 |
| **2026** | 7,364 | 1,055 | 1,275 | 7,769 | 6,462 | 2,354 | 4,470 | 13,963 | 26,237 | 7,809 | 2,579 | 2,132 | 131,033 | 214,502 |
| **2027** | 7,761 | 1,094 | 1,306 | 7,915 | 6,511 | 2,387 | 4,661 | 14,665 | 27,764 | 8,327 | 2,761 | 2,226 | 137,629 | 225,007 |
| **2028** | 8,175 | 1,134 | 1,337 | 8,061 | 6,559 | 2,420 | 4,855 | 15,392 | 29,389 | 8,870 | 2,954 | 2,323 | 144,139 | 235,608 |
| **2029** | 8,605 | 1,176 | 1,371 | 8,206 | 6,605 | 2,456 | 5,052 | 16,144 | 31,118 | 9,438 | 3,159 | 2,421 | 150,518 | 246,269 |
| **2030** | 8,998 | 1,219 | 1,403 | 8,323 | 6,619 | 2,491 | 5,193 | 16,798 | 32,985 | 9,917 | 3,357 | 2,497 | 152,232 | 252,032 |
| **2031** | 9,466 | 1,264 | 1,439 | 8,470 | 6,664 | 2,531 | 5,397 | 17,606 | 34,944 | 10,540 | 3,587 | 2,600 | 158,507 | 263,015 |
| **2040** | 14,940 | 1,751 | 1,825 | 9,864 | 7,146 | 3,017 | 7,637 | 26,862 | 59,196 | 18,234 | 6,523 | 3,743 | 227,997 | 388,733 |
| **2050** | 24,805 | 2,514 | 2,436 | 11,631 | 7,878 | 3,967 | 11,232 | 42,954 | 107,560 | 33,526 | 12,674 | 5,611 | 341,469 | 608,257 |

# Appendix B: Detailed Power Plant Assumptions

Table 14. Existing Thermal Power Stations

| Name of Station | Fuel [9] | Plant Capacity | Available Capacity | Heat Rate | Decomm-issioning Year | Forced Outage | Planned Outage | Variable O&M |
|---|---|---|---|---|---|---|---|---|
| | | MW | MW | GJ/MWh | | | hr/year | USD/MWh |
| **Senegal** | | | | | | | | |
| **Steam Turbine** | OHF | 87.5 | 53 | 12.9 | | 8% | 613 | 3.1 |
| **Diesel Generators** | OHF | 280.5 | 275.5 | 9.0 | | 10% | 960 | 10 |
| **Gas Turbine** | ODS | 76 | 66 | 16.3 | | 8% | 613 | 2.5 |
| **Combined Cycle** | GAS | 52 | 49 | 9.2 | | 8% | 613 | 2 |
| **Gambia** | | | | | | | | |
| **Diesel Generators** | ODS | 6 | 2.6 | 12.5 | | 10% | 960 | 10 |
| **Diesel Generators** | OHF | 61 | 46.6 | 9.7 | | 10% | 960 | 10 |
| **Guinea-Bissau** | | | | | | | | |
| **Diesel Generators** | ODS | 5.6 | 3.7 | 9.9 | | 25% | 960 | 10 |
| **Guinea** | | | | | | | | |
| **Diesel Generators** | OHF | 67.7 | 19 | 8.9 | 2012 | 10% | 960 | 10 |
| **Sierra Leone** | | | | | | | | |
| **Diesel Generators** | OHF | 45.9 | 38.7 | 9.5 | | 10% | 960 | 10 |
| **Diesel Generators** | ODS | 5 | 5 | 10.4 | | 10% | 960 | 10 |
| **Liberia** | | | | | | | | |
| **Diesel Generators** | ODS | 12.6 | 12.6 | 11.8 | | 10% | 960 | 10 |
| **Mali** | | | | | | | | |
| **Diesel Generators** | ODS | 56.9 | 56.9 | 9.7 | | 10% | 960 | 10 |
| **Gas Turbine** | ODS | 24.6 | 20 | 15.6 | | 8% | 613 | 2.5 |
| **Diesel Generators** | OHF | 57.5 | 57.5 | 9.4 | | 10% | 960 | 10 |

[9] OHF: Heavy fuel oil; ODS: Diesel/Naphta; GAS: Natural gas

| Name of Station | Fuel | Plant Capacity | Available Capacity | Heat Rate | Decomm-issioning Year | Forced Outage | Planned Outage | Variable O&M |
|---|---|---|---|---|---|---|---|---|
| | | MW | MW | GJ/MWh | | | hr/year | USD/MWh |
| **Cote D'Ivoire** | | | | | | | | |
| **Gas Turbine** | GAS | 2,960 | 290 | 11.4 | 2013 | 5% | 684 | 2.5 |
| **Gas Turbine** | GAS | 95.6 | 84 | 14.4 | | 3% | 693 | 2.5 |
| **Gas Turbine** | GAS | 214.5 | 210 | 12.1 | | 5% | 638 | 2.5 |
| **Gas Turbine** | GAS | 111 | 111 | 12.1 | | 5% | 636 | 2.5 |
| **Gas Turbine** | GAS | 70 | 70 | 12.1 | 2013 | 5% | 626 | 2.5 |
| **Ghana** | | | | | | | | |
| **Combined Cycle** | OLC | 330 | 300 | 8.7 | | 22% | 720 | 5 |
| **Gas Turbine** | OLC | 346 | 300 | 12.5 | | 13% | 576 | 6.5 |
| **Gas Turbine** | ODS | 129.5 | 85 | 12.3 | | 14% | 576 | 4.5 |
| **Combined Cycle** | GAS | 200 | 180 | 8.2 | | 7% | 720 | 2 |
| **Togo/Benin** | | | | | | | | |
| **Gas Turbine** | GAS | 156 | 139 | 13.3 | 2025 | 8% | 613 | 2.5 |
| **Diesel Generators** | ODS | 99.3 | 51.5 | 10.7 | 2013 | 10% | 960 | 10 |
| **Diesel Generators** | OHF | 16 | 5 | 12.9 | 2015 | 10% | 960 | 10 |
| **Burkina Faso** | | | | | | | | |
| **Diesel Generators** | ODS | 46 | 27 | 10.5 | | 8% | 1,289 | 10 |
| **Diesel Generators** | OHF | 1,328 | 119 | 9.6 | | 9% | 1,095 | 10 |
| **Niger** | | | | | | | | |
| **Steam Turbine** | COA | 32 | 32 | 10.8 | | 8% | 613 | 3.1 |
| **Diesel Generators** | ODS | 15.4 | 4.6 | 10.4 | | 10% | 960 | 10 |
| **Diesel Generators** | OHF | 12 | 10 | 9.5 | | 10% | 960 | 10 |
| **Gas Turbine** | GAS | 20 | 20 | 12.7 | | 8% | 613 | 2.5 |
| **Nigeria** | | | | | | | | |
| **Gas Turbine** | GAS | 4,147.7 | 2,558.7 | 12.7 | | 8% | 613 | 2.5 |
| **Steam Turbine** | GAS | 2,229.3 | 1,299.1 | 10.6 | | 8% | 613 | 3.1 |

Table 15. Existing Hydro Power Plants

| Name of Station | Hydro Type [10] | Plant Capacity | Available Capacity | Install-ation Year | Retirement Year | Forced Outage | Planned Outage | Variable O&M | Average Year | Dry year GWh |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MW | MW | | | | hr/year | USD/MWh | GWh | GWh |
| **Senegal** | | | | | | | | | | |
| **Manantali (OMVS) part Senegal 33%** | DAM | 67.6 | 67.6 | 1988 | | 5% | 570 | 2 | 264 | 165 |
| **Guinea** | | | | | | | | | | |
| **Baneah** | DAM | 5 | 1 | 1989 | 2015 | 5% | 570 | 2 | 6.4 | 5 |
| **Donkea** | ROR | 15 | 11 | 1970 | 2015 | 5% | 570 | 2 | 72.4 | 56 |
| **Grandes Chutes** | DAM | 27 | 3 | 1954 | 2015 | 5% | 570 | 2 | 127 | 99 |
| **Garafiri** | DAM | 75 | 75 | 1999 | | 5% | 570 | 2 | 258 | 204 |
| **Kinkon** | DAM | 3.4 | 3.4 | 2006 | | 5% | 570 | 2 | 11.6 | 11 |
| **Tinkisso** | ROR | 1.7 | 1.5 | 2005 | | 5% | 570 | 2 | 6.4 | 5 |
| **Sierra Leone** | | | | | | | | | | |
| **Goma 1** | ROR | 6 | 6 | 2007 | | 5% | 570 | 2 | 30.8 | 1 |
| **Bumbuna 1** | DAM | 50 | 50 | 2010 | | 5% | 570 | 2 | 290 | 157 |
| **Mali** | | | | | | | | | | |
| **Selingué** | DAM | 46.2 | 43.5 | 1980 | | 5% | 570 | 2 | 224.7 | 198 |
| **Sotuba** | ROR | 5.7 | 5.7 | 1966 | | 5% | 570 | 2 | 38.6 | 37 |
| **Manantali (OMVS) part Mali 52%** | DAM | 104 | 104 | 1988 | | 5% | 570 | 2 | 420 | 260 |
| **Cote d'Ivoire** | | | | | | | | | | |
| **Ayame 1** | DAM | 19.2 | 19.2 | 1998 | | 3% | 632 | 2 | 60 | 46 |
| **Ayame 2** | DAM | 30.4 | 30.4 | 1998 | | 3% | 1,920 | 2 | 90 | 68 |
| **Buyo** | DAM | 164.7 | 164.7 | 1980 | | 3% | 752 | 2 | 900 | 684 |
| **Kossou** | DAM | 175.5 | 175.5 | 2004 | | 3% | 856 | 2 | 505 | 384 |
| **Taabo** | DAM | 210.6 | 190 | 2004 | | 3% | 872 | 2 | 850 | 646 |
| **Faye** | ROR | 5 | 5 | 1984 | | 3% | 96 | 2 | 19 | 14 |

[10] DAM: Hydro with a dam; ROR: Run of river.

| Name of Station | Hydro Type | Plant Capacity | Available Capacity | Install-ation Year | Retirement Year | Forced Outage | Planned Outage | Variable O&M | Average Year | Dry year GWh |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MW | MW | | | | hr/year | USD/MWh | GWh | GWh |
| **Ghana** | | | | | | | | | | |
| **Akosombo** | DAM | 1,020 | 900 | 2005 | | 2% | 359 | 0 | 4,171 | 3,100 |
| **Kpong** | ROR | 160 | 144 | 1982 | | 2% | 359 | 0.1 | 880 | 622 |
| **Togo/Benin** | | | | | | | | | | |
| **Nangbeto** | DAM | 65.6 | 65 | 1987 | | 5% | 504 | 0 | 172.7 | 91 |
| **Burkina Faso** | | | | | | | | | | |
| **Bagre** | DAM | 14.4 | 11 | 1993 | 2018 | 5% | 570 | 2 | 55.8 | 21 |
| **Kompienga** | DAM | 12 | 9 | 1988 | 2013 | 5% | 570 | 2 | 30.9 | 16 |
| **Niofila** | ROR | 1.7 | 1.3 | 1996 | 2021 | 5% | 570 | 2 | 3.3 | 3 |
| **Tourni** | ROR | 0.6 | 0.5 | 1996 | 2021 | 5% | 570 | 2 | 1 | 1 |
| **Nigeria** | | | | | | | | | | |
| **Shiroro** | DAM | 600 | 480.3 | 1989 | | 5% | 570 | 2 | 2,628 | 1,945 |
| **Jebba** | DAM | 607.2 | 458 | 1986 | | 5% | 570 | 2 | 2,373 | 1,401 |
| **Kainji** | DAM | 781.2 | 420 | 1968 | | 5% | 570 | 2 | 2 ,475 | 1,286 |

Table 16. Considered and Committed Thermal Generation Projects

| Project Name | Plant type [11] | Fuel [12] | Available Capacity | Heat Rate | Start Year | Status | Forced Outage | Planned Outage | Variable O&M | Fixed O&M | Inv. Cost | Life |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | MW | GJ/MWh | | | | hr/yr | USD/MWh | USD/kW | USD/kW | years |
| **Senegal** | | | | | | | | | | | | |
| **Location** | DI | ODS | 150 | 10.4 | 2011 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **new mobile** | DI | OHF | 150 | 9.5 | 2011 | Planned | 10% | 960 | 10 | 0 | 1,418 | 30 |
| **relocation** | DI | OHF | 120 | 9.5 | 2017 | Considered | 10% | 960 | 10 | 0 | 1,418 | 30 |
| **IPP Tou** | DI | OHF | 60 | 9.5 | 2017 | Considered | 10% | 960 | 10 | 0 | 1,418 | 30 |
| **belair** | DI | OHF | 30 | 9.5 | 2012 | Committed | 10% | 960 | 10 | 0 | 1,418 | 30 |
| **unknown** | DI | OHF | 30 | 9.5 | 2017 | Considered | 10% | 960 | 10 | 0 | 1,418 | 30 |
| **Sendou** | ST | COA | 250 | 10.8 | 2016 | Committed | 8% | 613 | 3.1 | 0 | 971 | 35 |
| **Kayar** | ST | COA | 500 | 10.8 | 2017 | Considered | 8% | 613 | 3.1 | 0 | 2,489 | 35 |
| **St Louis** | ST | COA | 250 | 10.8 | 2017 | Considered | 8% | 613 | 3.1 | 0 | 2,489 | 35 |
| **ross betio** | BIO | BIO | 30 | 9.6 | 2014 | Committed | 8% | 613 | 0 | 130 | 3,910 | 30 |
| **St Louis WP** | WND | WND | 125 | 0 | 2014 | Considered | 70% | 0 | 10 | 17 | 1,934 | 20 |
| **ziguinchor** | SOL | SOL | 7.50 | 0 | 2014 | Considered | 75% | 0 | 0 | 20 | 5,030 | 20 |
| **taiba ndiaye** | WND | WND | 100 | 0 | 2016 | Considered | 70% | 0 | 10 | 17 | 1,934 | 20 |
| **Gambia** | | | | | | | | | | | | |
| **Brikama** | DI | OHF | 15.5 | 9.5 | 2012 | Committed | 10% | 960 | 10 | 0 | 1,418 | 30 |
| **Batokunku** | WND | WND | 1 | 0 | 2012 | Committed | 70% | 0 | 10 | 17 | 1,750 | 20 |
| **Guinea-Bissau** | | | | | | | | | | | | |
| **Bissau** | DI | OHF | 15 | 9.5 | 2012 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Guinea** | | | | | | | | | | | | |
| **Tombo (Rehab.)2012** | DI | OHF | 66.2 | 9.2 | 2012 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Maneah** | DI | OHF | 126 | 9.5 | 2014 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Sierra Leone** | | | | | | | | | | | | |
| **Energeon** | ST | BIO | 500 | 10.8 | 2018 | Considered | 8% | 613 | 3.1 | 0 | 2,489 | 35 |
| **Naanovo** | SOL | SOL | 5 | 0 | 2018 | Considered | 75% | 0 | 0 | 20 | 3,660 | 20 |
| **Addax** | BIO | BIO | 15 | 9.6 | 2018 | Considered | 8% | 613 | 0 | 130 | 3,604 | 30 |
| **Liberia** | | | | | | | | | | | | |
| **Bushrod** | DI | ODS | 10 | 11.8 | 2011 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Bushrod 2** | DI | OHF | 40 | 9.5 | 2013 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Kakata (Buchanan)** | BIO | BIO | 35 | 9.6 | 2013 | Planned | 8% | 613 | 0 | 130 | 3,604 | 30 |

[11] DI: Diesel Systems, ST: Steam Turbine, CC: Combined Cycle, BIO: biomass, WND: wind, SOL: Solar

[12] ODS: Diesel, OHF: Heavy Fuel Oil, COA: Coal, BIO: Biomass, WND: Wind, SOL: Solar

| Project Name | Plant type | Fuel | Available Capacity | Heat Rate | Start Year | Status | Forced Outage | Planned Outage | Variable O&M | Fixed O&M | Inv. Cost | Life |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | MW | GJ/MWh | | | | hr/yr | USD/MWh | USD/kW | USD/kW | years |
| **Mali** | | | | | | | | | | | | |
| **SIKASSO (CO)** | DI | ODS | 9.2 | 10.5 | 2011 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **KOUTIALA (CI)** | DI | ODS | 4.4 | 10.8 | 2012 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **KANGABA (CI)** | DI | ODS | 0.5 | 11.5 | 2014 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **BOUGOUNI (CI)** | DI | ODS | 2.5 | 11 | 2015 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **OUELESSEBOUGOU (CI)** | DI | ODS | 0.4 | 11.7 | 2016 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **SAN (CI)** | DI | ODS | 3.7 | 10.4 | 2017 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **TOMINIAN (CI)** | DI | ODS | 0.4 | 11.6 | 2017 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **MOPTI (CI)** | DI | ODS | 8.4 | 10.6 | 2018 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **DJENNE (CI)** | DI | ODS | 0.9 | 12.4 | 2018 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Balingue BID** | DI | OHF | 60 | 9.5 | 2011 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **VICA BOOT** | CC | BIO | 30 | 8.8 | 2012 | Planned | 8% | 613 | 2 | 0 | 957 | 25 |
| **Albatros BOOT** | DI | OHF | 92 | 9.5 | 2012 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Sosumar 1** | BIO | BIO | 3 | 9.6 | 2014 | Planned | 8% | 613 | 0 | 130 | 3,604 | 30 |
| **WAPP CC** | CC | ODS | 150 | 8.8 | 2019 | Considered | 8% | 613 | 2 | 0 | 957 | 25 |
| **WAPP SOLAR** | SOL | SOL | 30 | 0 | 2019 | Considered | 75% | 0 | 0 | 20 | 3,660 | 20 |
| **Mopti SOLAR** | SOL | SOL | 10 | 0 | 2012 | Committed | 75% | 0 | 0 | 20 | 3,660 | 20 |
| **Cote d'Ivoire** | | | | | | | | | | | | |
| **Vridi (CIPREL)** | CC | GAS | 333 | 8.8 | 2014 | Committed | 8% | 613 | 2 | 0 | 957 | 25 |
| **4e centrale IPP (Abbata)** | CC | GAS | 450 | 8.8 | 2014 | Planned | 8% | 613 | 2 | 0 | 957 | 25 |
| **Azito3** | CC | GAS | 430 | 8.8 | 2013 | Committed | 8% | 613 | 2 | 0 | 957 | 25 |
| **G2** | CC | GAS | 100 | 8.8 | 2013 | Committed | 8% | 613 | 2 | 0 | 957 | 25 |
| **Ghana** | | | | | | | | | | | | |
| **Effasu** | GT | ODS | 100 | 11.2 | 2015 | Planned | 20% | 576 | 4 | 0 | 633 | 25 |
| **Aboadze T3 phase 1** | CC | OLC | 120 | 8.2 | 2012 | Committed | 7% | 672 | 2 | 0 | 957 | 25 |
| **Domini T1** | CC | OLC | 300 | 11.6 | 2013 | Planned | 7% | 504 | 2 | 0 | 957 | 25 |
| **Tema T1** | CC | OLC | 210 | 11.6 | 2012 | Committed | 7% | 504 | 2 | 0 | 957 | 25 |
| **Aboadze T2** | CC | OLC | 100 | 8.1 | 2014 | Committed | 7% | 672 | 2 | 0 | 957 | 25 |
| **Sunon Asogli phase 2** | CC | GAS | 327.2 | 7.8 | 2013 | Committed | 7% | 672 | 2 | 0 | 957 | 25 |
| **Aboadze T3 phase 2** | CC | OLC | 127.3 | 8.2 | 2016 | Planned | 7% | 672 | 2 | 30 | 957 | 25 |
| **SolarPV** | SOL | SOL | 10 | 0 | 2012 | Committed | 75% | 0 | 0 | 20 | 3,660 | 20 |
| **Wind** | WND | WND | 150 | 0 | 2014 | Committed | 75% | 0 | 0 | 20 | 1,750 | 20 |
| **Aboadze T4 (WAPP)** | CC | GAS | 400 | 7.3 | 2015 | Committed | 7% | 672 | 2 | 30 | 957 | 25 |

## Table 16. Considered and Committed Thermal Generation Projects (continued)

| Project Name | Plant type | Fuel | Available Capacity | Heat Rate | Start Year | Status | Forced Outage | Planned Outage | Variable O&M | Fixed O&M | Inv. Cost | Life |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | MW | GJ/MWh | | | | hr/yr | USD/MWh | USD/kW | USD/kW | years |
| **Togo/Benin** | | | | | | | | | | | | |
| **CAI** | GT | GAS | 80 | 12.7 | 2011 | Committed | 8% | 613 | 2.5 | 0 | 633 | 25 |
| **IPP_SOLAR** | SOL | SOL | 20 | 0 | 2012 | Planned | 75% | 0 | 0 | 20 | 3,660 | 20 |
| **IPP_WIND** | WND | WND | 20 | 0 | 2013 | Planned | 70% | 0 | 10 | 17 | 1,750 | 20 |
| **IPP_THERMAL** | GT | GAS | 100 | 12.7 | 2013 | Planned | 8% | 613 | 2.5 | 0 | 633 | 25 |
| **CEB_SOLAR** | SOL | SOL | 10 | 0 | 2015 | Planned | 75% | 0 | 0 | 20 | 3,660 | 20 |
| **AFD_SOLAR** | SOL | SOL | 5 | 0 | 2014 | Planned | 75% | 0 | 0 | 20 | 3,660 | 20 |
| **MariaGleta** | CC | GAS | 450 | 8.8 | 2015 | Committed | 8% | 613 | 2 | 0 | 1,984 | 25 |
| **Burkina Faso** | | | | | | | | | | | | |
| **Ouahigouya** | DI | ODS | 4.3 | 10.4 | 2012 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Diebougou** | DI | ODS | 0.9 | 10.4 | 2011 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Gaoua** | DI | ODS | 1.3 | 10.4 | 2011 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Dori** | DI | ODS | 1.5 | 10.4 | 2011 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Gorom-Gorom** | DI | ODS | 0.3 | 10.4 | 2011 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Diapaga** | DI | ODS | 0.5 | 10.4 | 2013 | Planned | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Komsilga** | DI | OHF | 91.5 | 9.5 | 2011-2013 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Bobo 2** | DI | OHF | 20 | 9.5 | 2012 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Ouaga Solaire** | SOL | SOL | 20 | 0 | 2014 | Planned | 75% | 0 | 0 | 20 | 3,660 | 20 |
| **Mana (SEMAFO)** | SOL | SOL | 20 | 0 | 2012 | Planned | 75% | 0 | 0 | 20 | 3,660 | 20 |
| **Niger** | | | | | | | | | | | | |
| **TAG Niamey 2** | GT | GAS | 10 | 12.7 | 2011 | Planned | 8% | 613 | 2.5 | 0 | 633 | 25 |
| **Niamey 2** | DI | OHF | 15.4 | 9.5 | 2011 | Committed | 10% | 960 | 10 | 0 | 1,124 | 30 |
| **Goudel** | DI | OHF | 12 | 9.5 | 2012 | Planned | 10% | 960 | 10 | 0 | 2,058 | 30 |
| **Salkadamna** | ST | COA | 200 | 10.8 | 2015 | Considered | 8% | 613 | 3.1 | 0 | 8,575 | 35 |
| **Zinder** | CC | GAS | 8 | 8.8 | 2013 | Committed | 8% | 613 | 2 | 0 | 1,749 | 25 |
| **Wind** | WND | WND | 30 | 0 | 2014 | Planned | 70% | 0 | 10 | 17 | 1,578 | 20 |
| **Solar** | SOL | SOL | 50 | 0 | 2014 | Planned | 75% | 0 | 0 | 20 | 4,322 | 20 |
| **Nigeria** | | | | | | | | | | | | |
| **2011** | GT | GAS | 2,953 | 12.7 | 2011 | Committed | 8% | 613 | 2.5 | 0 | 633 | 25 |
| **2012** | GT | GAS | 4,126 | 12.7 | 2012 | Committed | 8% | 613 | 2.5 | 0 | 633 | 25 |
| **2013** | GT | GAS | 1,452 | 12.7 | 2013 | Committed | 8% | 613 | 2.5 | 0 | 633 | 25 |
| **ICSPower** | GT | GAS | 600 | 12.7 | 2015 | Planned | 8% | 613 | 2.5 | 0 | 633 | 25 |
| **SupertekNig.** | GT | GAS | 1,000 | 12.7 | 2017 | Planned | 8% | 613 | 2.5 | 0 | 633 | 25 |
| **Ethiope** | GT | GAS | 2,800 | 12.7 | 2017 | Planned | 8% | 613 | 2.5 | 0 | 633 | 25 |
| **FarmElectric** | GT | GAS | 150 | 12.7 | 2015 | Planned | 8% | 613 | 2.5 | 0 | 633 | 25 |
| **Westcom** | GT | GAS | 500 | 12.7 | 2015 | Planned | 8% | 613 | 2.5 | 0 | 633 | 25 |

Solar Panels in West Africa (ECREEE)

### Table 17. Considered and Committed Hydro Projects

| Name of Station | Hydro Type | Available Capacity | Start Year | Status | Forced Outage | Planned Outage | Variable O&M | Invest-ment Cost | Average Year | Dry Year |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MW | | | | hr/yr | USD/MWh | USD/kW | GWh | GWh |
| **Senegal** | | | | | | | | | | |
| **Sambangalou (OMVG) part Senegal 40%** | DAM | 51 | 2017 | Committed | 5% | 570 | 2 | 3,386 | 160.8 | 83.2 |
| **Kaleta (OMVG) part Senegal 40%** | ROR | 96 | 2016 | Planned | 5% | 570 | 2 | 1,114 | 378.4 | 90.8 |
| **Digan(OMVG) part Senegal 40%** | ROR | 37 | 2018 | Considered | 5% | 570 | 2 | 1,201 | 97.0 | 9.5 |
| **FelloSounga (OMVG) part Senegal 40%** | DAM | 33 | 2018 | Considered | 5% | 570 | 2 | 3,474 | 133.2 | 114.4 |
| **Saltinho(OMVG) part Senegal 40%** | ROR | 8 | 2018 | Considered | 5% | 570 | 2 | 4,273 | 32.8 | 9.5 |
| **Felou(OMVS) part Senegal 15%** | ROR | 15 | 2013 | Committed | 5% | 570 | 2 | 2,400 | 87.5 | 80.0 |
| **Gouina(OMVS) part Senegal 25%** | ROR | 35 | 2017 | Committed | 5% | 570 | 2 | 2,347 | 147.3 | 56.8 |
| **DAMConsidered** | DAM | 255 | 2019 | Considered | 5% | 570 | 2 | 4,311 | 950.8 | 656.1 |
| **Gambia** | | | | | | | | | | |
| **Sambangalou (OMVG) part Gambia 12%** | DAM | 15 | 2016 | Planned | 5% | 570 | 2 | 3,386 | 48.2 | 25.0 |
| **Kaleta (OMVG) part Gambia 12%** | ROR | 29 | 2016 | Planned | 5% | 570 | 2 | 1,114 | 113.5 | 27.2 |
| **Digan (OMVG) part Gambia 12%** | ROR | 11 | 2018 | Considered | 5% | 570 | 2 | 1,201 | 29.1 | 2.8 |
| **FelloSounga (OMVG) part Gambia 12%** | DAM | 10 | 2018 | Considered | 5% | 570 | 2 | 3,474 | 40.0 | 34.3 |
| **Saltinho (OMVG) part Gambia 12%** | ROR | 2 | 2018 | Considered | 5% | 570 | 2 | 4,273 | 9.8 | 2.8 |
| **Guinea-Bissau** | | | | | | | | | | |
| **Sambangalou (OMVG) part Guinea Bissau 8%** | DAM | 3 | 2016 | Planned | 5% | 570 | 2 | 3,386 | 9.7 | 5.0 |
| **Kaleta (OMVG) part Guinea Bissau 8%** | ROR | 6 | 2016 | Planned | 5% | 570 | 2 | 1,114 | 22.7 | 5.5 |
| **Digan (OMVG) part Guinea Bissau 8%** | ROR | 2 | 2018 | Considered | 5% | 570 | 2 | 1,201 | 5.8 | 0.6 |
| **FelloSounga (OMVG) part Guinea Bissau 8%** | DAM | 2 | 2018 | Considered | 5% | 570 | 2 | 3,474 | 8.0 | 6.9 |
| **Saltinho (OMVG) part Guinea Bissau 8%** | ROR | 0.5 | 2018 | Considered | 5% | 570 | 2 | 4,273 | 2.0 | 0.6 |

| Name of Station | Hydro Type | Available Capacity | Start Year | Status | Forced Outage | Planned Outage | Variable O&M | Invest-ment Cost | Average Year | Dry Year |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MW | | | | hr/yr | USD/MWh | USD/kW | GWh | GWh |
| **Guinea** | | | | | | | | | | |
| **Baneah (Rehab)** | DAM | 5 | 2015 | Committed | 5% | 570 | 2 | 2,400 | 6.4 | 4.9 |
| **Donkéa (Rehab)** | DAM | 15 | 2015 | Committed | 5% | 570 | 2 | 2,400 | 72.4 | 55.5 |
| **Grandes Chutes (Rehab)** | DAM | 27 | 2015 | Committed | 5% | 570 | 2 | 2,400 | 127.0 | 99.2 |
| **Sambangalou (OMVG) part Guinea 40%** | DAM | 51.2 | 2016 | Planned | 5% | 570 | 2 | 3,386 | 160.8 | 83.2 |
| **Kaleta (OMVG) part Guinea 40%** | DAM | 240 | 2015 | Committed | 5% | 570 | 2 | 1,114 | 946.0 | 227.0 |
| **Digan (OMVG) part Guinea 40%** | DAM | 37 | 2018 | Considered | 5% | 570 | 2 | 1,201 | 97.0 | 9.5 |
| **FelloSounga (OMVG) part Guinea 40%** | DAM | 32.8 | 2018 | Considered | 5% | 570 | 2 | 3,474 | 133.2 | 114.4 |
| **DAM Considered** | DAM | 2,929 | 2019 | Considered | 5% | 570 | 2 | 2,400 | 12,720.3 | 10,370.8 |
| **Saltinho (OMVG) part Guinea 40%** | DAM | 8 | 2018 | Considered | 5% | 570 | 2 | 4,273 | 32.8 | 9.5 |
| **Sierra Leone** | | | | | | | | | | |
| **Goma2 (Bo-Kenema)** | ROR | 6 | 2015 | Planned | 5% | 570 | 2 | 6,709 | 30.8 | 1.4 |
| **Bumbuna2** | DAM | 40 | 2015 | Planned | 5% | 570 | 2 | 1,950 | 220.0 | 237.0 |
| **Bumbuna3 (Yiben)** | DAM | 90 | 2017 | Planned | 5% | 570 | 2 | 1,950 | 396.0 | 317.0 |
| **Bumbuna 4&5** | DAM | 95 | 2017 | Planned | 5% | 570 | 2 | 1,950 | 494.0 | 463.0 |
| **Benkongor 1** | DAM | 35 | 2020 | Planned | 5% | 570 | 2 | 2,447 | 237.2 | 199.7 |
| **Benkongor 2** | DAM | 80 | 2022 | Planned | 5% | 570 | 2 | 2,447 | 413.7 | 338.3 |
| **Benkongor 3** | DAM | 86 | 2025 | Planned | 5% | 570 | 2 | 2,447 | 513.1 | 421.1 |
| **DAM Considered** | DAM | 323 | 2026 | Considered | 5% | 570 | 2 | 2,561 | 1,863.2 | 1,490.5 |
| **Liberia** | | | | | | | | | | |
| **Mount Coffee (+Via reservoir)** | DAM | 66 | 2015 | Committed | 5% | 570 | 2 | 5,803 | 435.0 | 344.0 |
| **SaintPaul -1B** | DAM | 78 | 2017 | Considered | 5% | 570 | 2 | 3,123 | 512.0 | 389.1 |
| **SaintPaul -2** | DAM | 120 | 2017 | Considered | 5% | 570 | 2 | 3,123 | 788.0 | 598.9 |
| **DAM Considered** | DAM | 702.5 | 2019 | Considered | 5% | 570 | 2 | 3,123 | 3,027.7 | 2,301.1 |

Table 17. Considered and Committed Hydro Projects (continued)

| Name of Station | Hydro Type | Available Capacity | Start Year | Status | Forced Outage | Planned Outage | Variable O&M | Invest-ment Cost | Average Year | Dry Year |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MW | | | | hr/yr | USD/MWh | USD/kW | GWh | GWh |
| **Mali** | | | | | | | | | | |
| **Sotuba2** | ROR | 6 | 2014 | Planned | 5% | 570 | 2 | 2,400 | 39.0 | 37.4 |
| **Kenié** | ROR | 42 | 2015 | Planned | 5% | 570 | 2 | 3,670.7 | 199.0 | 162.6 |
| **Gouina (OMVS) part Mali 45%** | ROR | 63 | 2017 | Committed | 5% | 570 | 2 | 2,347 | 265.1 | 102.0 |
| **Felou (OMVS) part Mali 45%** | ROR | 27 | 2013 | Committed | 5% | 570 | 2 | 2,347 | 265.1 | 102.0 |
| **DAM Considered** | DAM | 303 | 2018 | Considered | 5% | 570 | 2 | 4,025 | 1,085.8 | 825.2 |
| **Cote d'Ivoire** | | | | | | | | | | |
| **Soubre** | DAM | 270 | 2018 | Planned | 5% | 570 | 2 | 2,400 | 1 116.0 | 0.0 |
| **Aboisso Comoé** | DAM | 90 | 2026 | Considered | 5% | 570 | 2 | 2,756 | 392.0 | 297.9 |
| **Gribo Popoli** | DAM | 112 | 2027 | Considered | 5% | 570 | 2 | 3,249 | 515.0 | 391.4 |
| **Boutoubré** | DAM | 156 | 2028 | Considered | 5% | 570 | 2 | 2,570 | 785.0 | 596.6 |
| **Louga** | DAM | 280 | 2029 | Considered | 5% | 570 | 2 | 4,751 | 1,330.0 | 1,010.8 |
| **Tiboto / Cavally (Intl.) partCI 50%** | DAM | 112 | 2030 | Considered | 5% | 570 | 2 | 2,570 | 600.0 | 456.0 |
| **Tiassalé** | ROR | 51 | 2030 | Considered | 5% | 570 | 2 | 4,068 | 215.0 | 163.4 |
| **Ghana** | | | | | | | | | | |
| **Bui** | DAM | 342 | 2013 | Committed | 1% | 350 | 0 | 2,400 | 1,000.0 | 0.0 |
| **Juale** | DAM | 87 | 2014 | Considered | 1% | 350 | 0.1 | 3,552 | 405.0 | 307.8 |
| **Pwalugu** | DAM | 48 | 2014 | Considered | 1% | 350 | 0.1 | 3,625 | 184.0 | 139.8 |
| **Hemang** | ROR | 93 | 2014 | Considered | 1% | 350 | 0.1 | 2,688 | 340.0 | 258.4 |
| **Kulpawn** | DAM | 36 | 2014 | Considered | 1% | 350 | 0.1 | 8 111 | 166.0 | 126.2 |
| **Daboya** | DAM | 43 | 2014 | Considered | 1% | 350 | 0.1 | 4,698 | 194.0 | 147.4 |
| **Noumbiel (Intl.) part Ghana 20%** | DAM | 12 | 2014 | Considered | 1% | 350 | 2 | 4,767 | 40.6 | 30.9 |

| Name of Station | Hydro Type | Available Capacity | Start Year | Status | Forced Outage | Planned Outage | Variable O&M | Invest-ment Cost | Average Year | Dry Year |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MW | | | | hr/yr | USD/MWh | USD/kW | GWh | GWh |
| **Togo/Benin** | | | | | | | | | | |
| **Adjarala** | DAM | 147 | 2017 | Committed | 5% | 570 | 2 | 2,264 | 366.0 | 237.0 |
| **Ketou** | DAM | 160 | 2018 | Considered | 5% | 570 | 2 | 2,105 | 490.0 | 372.4 |
| **Tetetou** | DAM | 50 | 2018 | Considered | 5% | 570 | 2 | 3,174 | 148.0 | 112.5 |
| **Burkina Faso** | | | | | | | | 5,839 | 192 | 146 |
| **Noumbiel** | DAM | 48 | 2021 | Considered | 5% | 570 | 2 | 4,767 | 162.4 | 123.4 |
| **Bougouriba** | DAM | 12 | 2021 | Considered | 5% | 570 | 2 | 10,125 | 30.0 | 22.8 |
| **Niger** | | | | | | | | | | |
| **Kandadji** | DAM | 130 | 2015 | Committed | 5% | 570 | 2 | 2,400 | 629.0 | 0.0 |
| **Gambou** | DAM | 122 | 2016 | Considered | 5% | 570 | 2 | 4,712 | 528.0 | 401.3 |
| **Dyodyonga** | DAM | 26 | 2016 | Considered | 5% | 570 | 2 | 2,293 | 112.1 | 85.2 |
| **Nigeria** | | | | | | | | | | |
| **Mambilla** | DAM | 2,600 | 2017 | Considered | 5% | 570 | 2 | 1,538 | 11,205.8 | 8,516.4 |
| **Zungeru** | DAM | 700 | 2018 | Considered | 5% | 570 | 2 | 1,538 | 3,016.9 | 2,292.9 |


Richard Waters©A solar thermal installation, providing hot water/Shutterstock

# Appendix C: Generic Technology Parameters

Table 18. Other Parameters for Renewable Energy Technologies

| | Load Factor | O&M | Thermal Efficiency | Construction Duration | Life |
|---|---|---|---|---|---|
| | | USD/MWh | | Years | Years |
| **Diesel/Gasoline 1 kW system (urban/rural)** | 30% | 33.2 | 16% | 0 | 10 |
| **Diesel 100 kW system (industry)** | 80% | 55.4 | 35% | 0 | 20 |
| **Diesel Centralised** | 80% | 17.0 | 35% | 2 | 25 |
| **Heavy Fuel Oil** | 80% | 15.0 | 35% | 2 | 25 |
| **Open cycle Gas Turbine (OCGT)** | 85% | 19.9 | 30% | 2 | 25 |
| **Combined Cycle Gas Turbine (CCGT)** | 85% | 2.9 | 48% | 3 | 30 |
| **Supercritical coal** | 85% | 14.3 | 37% | 4 | 35 |
| **Small hydro** | 50% | 5.4 | - | 2 | 30 |
| **Biomass** | 50% | 20.0 | 38% | 4 | 30 |
| **Bulk wind (20% CF)** | 20% | 17.4 | - | 2 | 25 |
| **Bulk wind (30% CF)** | 30% | 14.3 | - | 2 | 25 |
| **Solar PV (utility)** | 25% | 20.1 | - | 1 | 25 |
| **Solar PV (rooftop)** | 20% | 23.8 | - | 1 | 20 |
| **PV with battery 1h storage** | 22.5% | 19.0 | - | 1 | 20 |
| **PV with battery 2h storage** | 25% | 17.1 | - | 1 | 20 |
| **CSP no storage** | 35% | 22.3 | - | 4 | 25 |
| **CSP with storage** | 63% | 18.9 | - | 4 | 25 |
| **CSP with gas co-firing** | 85% | 18.9 | 53% | 4 | 25 |

Table 19. Levelised Cost of Electricity: Comparisons in 2010

| | Grid Connection | Generation (without T&D) | Ind. | Urban | Rural | Urban + $CO_2$ | Generation (without T&D) | Ind. | Urban | Rural | Urban + $CO_2$ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Levelised Cost of Electricity (USD/MWh) | | | | | Ranking (cheapest to most expensive) | | | | |
| **Diesel centralised** | Y | 291 | 328 | 433 | 516 | 452 | 18 | 16 | 18 | 19 | 18 |
| **Dist. diesel 100 kW** | N | 320 | 320 | | | | 19 | 15 | | | |
| **Dist. diesel/gasoline 1 kW** | N | 604 | | 604 | 604 | 645 | 21 | | 19 | 20 | 19 |
| **HFO** | Y | 188 | 217 | 298 | 369 | 319 | 16 | 14 | 16 | 18 | 16 |
| **OCGT (domestic gas)** | Y | 141 | 167 | 236 | 301 | 252 | 11 | 10 | 11 | 13 | 14 |
| **CCGT (imported gas/LNG)** | Y | 111 | 134 | 196 | 258 | 206 | 9 | 8 | 9 | 11 | 8 |
| **CCGT (domestic gas)** | Y | 90 | 112 | 168 | 229 | 179 | 3 | 3 | 4 | 5 | 3 |
| **Supercritical coal** | Y | 101 | 124 | 183 | 244 | 206 | 4 | 4 | 5 | 6 | 9 |
| **Supercritical domestic coal** | Y | 81 | 102 | 157 | 216 | 180 | 2 | 2 | 3 | 4 | 4 |
| **Hydro** | Y | 62 | 82 | 132 | 189 | 132 | 1 | 1 | 1 | 3 | 1 |
| **Small hydro** | N | 107 | | | 107 | | 8 | | | 1 | |
| **Biomass** | Y | 104 | 127 | 187 | 249 | 187 | 6 | 6 | 7 | 8 | 6 |
| **Bulk wind (20% CF)** | Y | 149 | 176 | 247 | 314 | 247 | 14 | 12 | 13 | 15 | 12 |
| **Bulk wind (30% CF)** | Y | 102 | 125 | 185 | 246 | 185 | 5 | 5 | 6 | 7 | 5 |
| **Solar PV (utility)** | Y | 121 | 145 | 209 | 272 | 209 | 10 | 9 | 10 | 12 | 10 |
| **Solar PV (rooftop)** | N | 143 | | 143 | 143 | 143 | 12 | | 2 | 2 | 2 |
| **PV with battery (1h storage)** | N | 250 | | 250 | 250 | 250 | 17 | | 14 | 9 | 13 |
| **PV with battery (2h storage)** | N | 323 | | 323 | 323 | 323 | 20 | | 17 | 16 | 17 |
| **CSP no storage** | Y | 147 | 173 | 244 | 311 | 244 | 13 | 11 | 12 | 14 | 11 |
| **CSP with storage** | Y | 177 | 205 | 282 | 352 | 282 | 15 | 13 | 15 | 17 | 15 |
| **CSP with gas co-firing** | Y | 106 | 129 | 189 | 251 | 199 | 7 | 7 | 8 | 10 | 7 |

Table 20. Levelised Cost of Electricity: Comparisons in 2020

| | Grid Connection | Generation (without T&D) | Ind. | Urban | Rural | Urban + $CO_2$ | Generation (without T&D) | Ind. | Urban | Rural | Urban + $CO_2$ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Levelised Cost of Electricity (USD/MWh) | | | | | Ranking (cheapest to most expensive) | | | | |
| **Diesel centralised** | Y | 325 | 364 | 432 | 533 | 451 | 19 | 16 | 18 | 19 | 18 |
| **Dist. diesel 100 kW** | N | 355 | 355 | | | | 20 | 15 | | | |
| **Dist. diesel/gasoline 1 kW** | N | 693 | | 693 | 693 | 735 | 21 | | 19 | 20 | 19 |
| **HFO** | Y | 208 | 238 | 295 | 377 | 315 | 17 | 14 | 17 | 18 | 17 |
| **OCGT (domestic gas)** | Y | 154 | 180 | 231 | 305 | 247 | 15 | 13 | 15 | 17 | 16 |
| **CCGT (imported gas/LNG)** | Y | 120 | 144 | 192 | 261 | 202 | 12 | 10 | 12 | 14 | 13 |
| **CCGT (domestic gas)** | Y | 98 | 120 | 165 | 230 | 175 | 7 | 6 | 7 | 9 | 6 |
| **Supercritical coal** | Y | 104 | 127 | 173 | 239 | 196 | 8 | 7 | 8 | 11 | 11 |
| **Supercritical domestic coal** | Y | 89 | 110 | 154 | 218 | 178 | 3 | 3 | 4 | 6 | 7 |
| **Hydro** | Y | 62 | 82 | 123 | 183 | 123 | 1 | 1 | 2 | 4 | 2 |
| **Small hydro** | N | 97 | | | 97 | | 6 | | | 1 | |
| **Biomass** | Y | 92 | 114 | 158 | 222 | 158 | 4 | 4 | 5 | 7 | 4 |
| **Bulk wind (20% CF)** | Y | 128 | 152 | 200 | 270 | 200 | 13 | 11 | 13 | 15 | 12 |
| **Bulk wind (30% CF)** | Y | 88 | 109 | 153 | 217 | 153 | 2 | 2 | 3 | 5 | 3 |
| **Solar PV (utility)** | Y | 94 | 116 | 161 | 226 | 161 | 5 | 5 | 6 | 8 | 5 |
| **Solar PV (rooftop)** | N | 109 | | 109 | 109 | 109 | 9 | | 1 | 2 | 1 |
| **PV with battery (1h storage)** | N | 181 | | 181 | 181 | 181 | 16 | | 9 | 3 | 8 |
| **PV with battery (2h storage)** | N | 231 | | 231 | 231 | 231 | 18 | | 16 | 10 | 15 |
| **CSP no storage** | Y | 119 | 143 | 190 | 259 | 190 | 11 | 9 | 11 | 13 | 9 |
| **CSP with storage** | Y | 138 | 164 | 213 | 284 | 213 | 14 | 12 | 14 | 16 | 14 |
| **CSP with gas co-firing** | Y | 111 | 135 | 181 | 248 | 191 | 10 | 8 | 10 | 12 | 10 |

Table 21: Levelsed Cost of Electricity:  Comparisons in 2030

| | Grid Connec-tion | Gener-ation (without T&D) | Ind. | Urban | Rural | Urban + $CO_2$ | Gener-ation (without T&D) | Ind. | Urban | Rural | Urban + $CO_2$ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Levelised Cost of Electricity (USD/MWh) | | | | | Ranking (cheapest to most expensive) | | | | |
| **Diesel centralised** | Y | 339 | 376 | 440 | 552 | 459 | 16 | 16 | 18 | 19 | 18 |
| **Dist. diesel 100 kW** | N | 371 | 371 | | | | 15 | 15 | | | |
| **Dist. diesel/gasoline 1 kW** | N | 740 | | 740 | 740 | 782 | | | 19 | 20 | 19 |
| **HFO** | Y | 216 | 245 | 299 | 389 | 319 | 14 | 14 | 17 | 18 | 17 |
| **OCGT (domestic gas)** | Y | 161 | 187 | 235 | 315 | 252 | 13 | 13 | 16 | 17 | 16 |
| **CCGT (imported gas/LNG)** | Y | 126 | 150 | 195 | 269 | 206 | 12 | 12 | 15 | 16 | 15 |
| **CCGT (domestic gas)** | Y | 102 | 124 | 167 | 236 | 178 | 7 | 7 | 9 | 11 | 8 |
| **Supercritical coal** | Y | 106 | 127 | 172 | 241 | 195 | 8 | 8 | 10 | 12 | 14 |
| **Supercritical domestic coal** | Y | 93 | 114 | 157 | 224 | 180 | 5 | 5 | 7 | 9 | 9 |
| **Hydro** | Y | 62 | 81 | 122 | 183 | 122 | 1 | 1 | 2 | 4 | 2 |
| **Small hydro** | N | 89 | | | 89 | | | | | 1 | |
| **Biomass** | Y | 86 | 107 | 149 | 215 | 149 | 4 | 4 | 5 | 8 | 5 |
| **Bulk wind (20% CF)** | Y | 117 | 139 | 184 | 256 | 184 | 11 | 11 | 13 | 15 | 11 |
| **Bulk wind (30% CF)** | Y | 81 | 101 | 143 | 208 | 143 | 2 | 2 | 3 | 6 | 3 |
| **Solar PV (utility)** | Y | 84 | 104 | 146 | 212 | 146 | 3 | 3 | 4 | 7 | 4 |
| **Solar PV (rooftop)** | N | 96 | | 96 | 96 | 96 | | | 1 | 2 | 1 |
| **PV with battery (1h storage)** | N | 151 | | 151 | 151 | 151 | | | 6 | 3 | 6 |
| **PV with battery (2h storage)** | N | 192 | | 192 | 192 | 192 | | | 14 | 5 | 13 |
| **CSP no storage** | Y | 102 | 123 | 167 | 236 | 167 | 6 | 6 | 8 | 10 | 7 |
| **CSP with storage** | Y | 116 | 139 | 184 | 255 | 184 | 10 | 10 | 12 | 14 | 10 |
| **CSP with gas co-firing** | Y | 115 | 137 | 182 | 253 | 191 | 9 | 9 | 11 | 13 | 12 |


ZSM©Akosombo Dam spilling water, Ghana/Wikimedia

Dennis Schroeder©Pretreatment reactor in the Integrated Biorefinery Research Facility/NREL

# Appendix D: Detailed Transmission Data

Table 22. Detailed Data for Existing Transmission Infrastructure

| Country 1 | Country 2 | Line Voltage | Line Capacity | Loss Coefficient | Forced Outage Rate |
|---|---|---|---|---|---|
| | | kV | MW | | |
| Ghana | Cote d'Ivoire | 225 | 327 | 220% | 3.03% |
| Ghana | Togo/Benin | 161x2* | 310 | 91.3% | 2.50% |
| Senegal | Mali | 225 | 100 | 1,200% | 5.46% |
| Cote d'Ivoire | Burkina | 225 | 327 | 221.8% | 3.48% |
| Nigeria | Togo/Benin | 330 | 686 | 75% | 2.50% |
| Nigeria | Niger | 132x2* | 169 | 162% | 2.62% |

* Two transmission lines are represented. Links between Ghana and Togo/Benin include Akosomba—Loma and Dapaong—Bawku. Links between Nigeria and Niger include Birnin-Kebbi—Niamey and Katsina—Gazaoua.

Table 23. Detailed Data for Future Transmission Projects

| From | To | Stations | Voltage | Capacity per Line | Distance | Losses | Total Investment | Investment Cost | Earliest Year |
|---|---|---|---|---|---|---|---|---|---|
| | | | kV | MW | km | | USD million | USD/kW | |
| **Dorsale 330 kV (committed)** | | | | | | | | | |
| **Ghana** | **Togo/Benin** | Volta - Sakete | 330 | 655.2 | 240 | 2.50% | 90.0 | 137.4 | 2013 |
| **Cote d'Ivoire** | **Ghana** | Riviera - Presea | 330 | 655.2 | 240 | 2.00% | 90.0 | 137.4 | 2015 |
| **CLSG (committed)** | | | | | | | | | |
| **Cote d'Ivoire** | **Liberia** | Man (CI) - Yekepa (LI) | 225 | 337.6 | 140 | 2.50% | 59.7 | 176.9 | 2014 |
| **Liberia** | **Guinea** | Yekepa (LI) - Nzerekore (GU) | 225 | 337.6 | 140 | 2.50% | 59.7 | 176.9 | 2014 |
| **Liberia** | **Sierra Leone** | Yekepa (LI) - Buchanan (LI) - Monrovia (LI) - Bumbuna (SI) | 225 | 303.4 | 580 | 6.79% | 247.5 | 815.6 | 2014 |
| **Sierra Leone** | **Guinea** | Bumbuna (SI) - Linsan (GU) | 225 | 333.7 | 190 | 2.50% | 81.1 | 242.9 | 2014 |
| **OMVG (Committed)** | | | | | | | | | |
| **Senegal** | **Guinea** | Kaolack (SE) - Linsan (GU) | 225 | 286.3 | 800 | 9.37% | 289.8 | 1,012.3 | 2017 |
| **Senegal** | **Gambia** | Birkelane (SE) - Soma (GA) | 225 | 340.7 | 100 | 2.50% | 36.2 | 106.3 | 2017 |
| **Gambia** | **Guinea-Bissau** | Soma (GA) - Bissau (GB) | 225 | 329.1 | 250 | 2.93% | 90.6 | 275.3 | 2017 |
| **Guinea-Bissau** | **Guinea** | Mansoa (GB) - Linsan (GU) | 225 | 309.6 | 500 | 5.86% | 181.2 | 585.0 | 2017 |
| **Corridor Nord** | | | | | | | | | |
| **Nigeria** | **Niger** | Birnin Kebbi (NG) -Niamey (NI) | 330 | 653.1 | 268 | 3.14% | 143.1 | 219.1 | 2014 |
| **Niger** | **Togo/Benin** | Zabori (NI) - Bembereke (TB) | 330 | 649.7 | 312 | 3.65% | 166.6 | 256.4 | 2014 |
| **Niger** | **Burkina Faso** | Niamey (NI) - Ouagadougou (BU) | 330 | 637.5 | 469 | 5.49% | 250.4 | 392.8 | 2014 |

| From | To | Stations | Voltage | Capacity per Line | Distance | Losses | Total Investment | Investment Cost | Earliest Year |
|---|---|---|---|---|---|---|---|---|---|
| | | | kV | MW | km | | USD million | USD/kW | |
| **Hub Intrazonal** | | | | | | | | | |
| **Ghana** | **Burkina Faso** | Han (GH) - Bobo Dioulasse (BU) | 225 | 332.2 | 210 | 2.50% | 67.0 | 201.7 | 2014 |
| **Burkina** | **Mali** | Bobo Dioulasse (BU) - Sikasso (MA) | 225 | 305.8 | 550 | 6.44% | 175.5 | 573.9 | 2015 |
| **Mali** | **Cote d'Ivoire** | Segou (MA) - Ferkessedougou (CI) | 225 | 319.7 | 370 | 4.33% | 136.9 | 428.3 | 2016 |
| **Guinea** | **Mali** | Fomi (GU) – Bamako (MA) | 225 | 321.3 | 350 | 4.10% | 117.6 | 366.1 | 2020 |
| **Dorsale Mediane** | | | | | | | | | |
| **Nigeria** | **Togo/ Benin** | Kaindhji (NG) - Kara/Bembereke/ Parakou (TB) | 330 | 646.7 | 350 | 4.10% | 164.6 | 254.6 | 2020 |
| **Togo/ Benin** | **Ghana** | Kara/Bembereke/ Parakou (TB) - Yendi (GH) | 330 | 654.5 | 250 | 2.93% | 117.6 | 179.7 | 2020 |
| **OMVS** | | | | | | | | | |
| **Mali** | **Senegal** | Gouina (MA) - Tambacounda (SE) | 225 | 329.1 | 250 | 2.93% | 94.6 | 287.6 | 2020 |

Table 24 Detailed Transmission and Distribution Losses by Country

| | Transmission Losses | Distribution Losses | | | |
|---|---|---|---|---|---|
| | | 2010 | 2020 | 2030 | 2050 |
| **Senegal** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 20.5% | 10% | 8% | 8% |
| **Rural** | 5% | 25% | 20% | 20% | 20% |
| **Gambia** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 25% | 10% | 8% | 8% |
| **Rural** | 5% | 30% | 20% | 20% | 20% |
| **Guinea-Bissau** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 25% | 10% | 8% | 8% |
| **Rural** | 5% | 30% | 20% | 20% | 20% |
| **Guinea** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 25% | 10% | 8% | 8% |
| **Rural** | 5% | 30% | 20% | 20% | 20% |
| **Sierra Leone** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 25% | 10% | 8% | 8% |
| **Rural** | 5% | 30% | 20% | 20% | 20% |
| **Liberia** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 25% | 10% | 8% | 8% |
| **Rural** | 5% | 30% | 20% | 20% | 20% |

| | Transmission Losses | Distribution Losses | | | |
|---|---|---|---|---|---|
| | | 2010 | 2020 | 2030 | 2050 |
| **Mali** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 19% | 10% | 8% | 8% |
| **Rural** | 5% | 25% | 20% | 20% | 20% |
| **Cote d'Ivoire** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 19.5% | 10% | 8% | 8% |
| **Rural** | 5% | 25% | 20% | 20% | 20% |
| **Ghana** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 19.5% | 10% | 8% | 8% |
| **Rural** | 5% | 25% | 20% | 20% | 20% |
| **Togo/Benin** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 19.5% | 10% | 8% | 8% |
| **Rural** | 5% | 25% | 20% | 20% | 20% |
| **Burkina** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 12% | 10% | 8% | 8% |
| **Rural** | 5% | 15% | 15% | 15% | 15% |
| **Niger** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 12% | 10% | 8% | 8% |
| **Rural** | 5% | 20% | 20% | 20% | 20% |
| **Nigeria** | | | | | |
| **Heavy Industry** | 5% | 2% | 2% | 0% | 0% |
| **Urban/Services/Small Industry** | 5% | 12% | 10% | 8% | 8% |
| **Rural** | 5% | 30% | 20% | 20% | 20% |

Ocean Power Technologies©OPT Power Buoy

# Appendix E: Detailed Build Plan in the Renewable Promotion Scenario

## TRANSMISSION PROJECTS

### Dorsale

2013 Ghana to Togo/Benin 655 MW

2017 Cote d'Ivoire to Ghana 655 MW

### CLSG

2015 Cote d'Ivoire to Liberia 338 MW, Liberia to Guinea 338 MW, Liberia to Sierra Leone 303 MW, Sierra Leone to Guinea 334 MW

### OMVG

2017 Senegal to Guinea 286 MW, Senegal to Gambia 341 MW, Guinea to Senegal 286 MW, Gambia to Senegal 341 MW

### Hub Intrazonal

2012 Mali to Cote d'Ivoire 320 MW
2013 Ghana to Burkina Faso 332 MW
2015 Ghana to Burkina Faso 332 MW
2016 Guinea to Mali 95MW

### Dorsale Mediane

2026 Nigeria to Togo/Benin 67MW
2030 Nigeria to Togo/Benin 418MW

### Nigeria – Benin

2025 Nigeria to Togo/Benin 43MW
2026 Nigeria to Togo/Benin 286MW

### Central Africa – Nigeria

2025 Central Africa to Nigeria 1,000 MW
2026 Central Africa to Nigeria 1,000 MW
2027 Central Africa to Nigeria 1,000 MW
2028 Central Africa to Nigeria 1,000 MW
2029 Central Africa to Nigeria 1,000 MW
2030 Central Africa to Nigeria 1,000 MW

# GENERATION PROJECTS BY COUNTRY

## Burkina Faso

### Centralised

- 2011 Komsilga 56MW
- 2012 Bobo-2 20MW
- 2013 Komsilga 36MW
- 2014 Bulk Wind (30% CF) 29MW
- 2020 Biomass 12MW
- 2021 Biomass 26MW
- 2022 Biomass 24MW, Solar PV (utility) 79MW
- 2023 Biomass 22MW, Solar PV (utility) 5MW
- 2024 Biomass 22MW, Solar PV (utility) 6MW
- 2025 Biomass 30MW, Solar PV (utility) 6MW
- 2026 Biomass 24MW, Solar PV (utility) 6MW
- 2027 Biomass 17MW, Solar PV (utility) 7MW, Solar thermal no storage 26MW
- 2028 Solar PV (utility) 7MW, Solar thermal no storage 108MW
- 2029 Solar thermal no storage 150MW
- 2030 Solar thermal no storage 83MW

### De-Centralised

- 2010 Diesel/Gasoline 1kW system (Urban) 1MW
- 2012 Diesel/Gasoline 1kW system (Urban) 4MW
- 2013 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 11MW
- 2014 Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 11MW
- 2015 Small Hydro 1MW
- 2016 Small Hydro 2MW
- 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 3MW
- 2019 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2020 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 11MW

- » 2021 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 3MW
- » 2022 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 2MW
- » 2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 15MW
- » 2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 16MW
- » 2025 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 5MW
- » 2026 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 5MW
- » 2027 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 4MW
- » 2028 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 7MW
- » 2029 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 3MW
- » 2030 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 12MW, Rooftop PV with 1h Battery 64MW

## Cote d’Ivoire

### Centralised

- » 2013 5e centrale IPP (Bassam) 430MW, Lushann 100MW
- » 2014 Vridi (CIPREL) 222MW, 4e centrale IPP (Abbata) 150MW
- » 2015 Vridi (CIPREL) 111MW, 4e centrale IPP (Abbata) 150MW
- » 2016 4e centrale IPP (Abbata) 150MW, CCGT 1,000MW
- » 2017 CCGT 268MW
- » 2024 Solar PV (utility) 112MW
- » 2026 Solar PV (utility) 468MW
- » 2027 Solar PV (utility) 29MW
- » 2028 Boutoubré 156MW, Solar PV (utility) 30MW
- » 2029 Solar PV (utility) 30MW
- » 2030 Tiboto/Cavally(Intl.) partCI 50% 113MW, Solar PV (utility) 25MW

### De-Centralised

- » 2011 Diesel/Gasoline 1kW system (Rural) 6MW, Diesel/Gasoline 1kW system (Urban) 26MW
- » 2012 Diesel/Gasoline 1kW system (Urban) 86MW
- » 2014 Small Hydro 25MW, Diesel/Gasoline 1kW system (Urban) 27MW
- » 2015 Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 24MW

» 2016 Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 23MW

» 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 23MW

» 2018 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 23MW

» 2019 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 23MW

» 2020 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 9MW

» 2021 Diesel/Gasoline 1kW system (Rural) 7MW, Small Hydro 11MW, Diesel/Gasoline 1kW system (Urban) 38MW

» 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 98MW

» 2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 13MW

» 2024 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 9MW

» 2025 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW

» 2026 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 9MW

» 2027 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 10MW

» 2028 Diesel/Gasoline 1kW system (Rural) 7MW, Small Hydro 12MW

» 2029 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 20MW

» 2030 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 12MW, Diesel/Gasoline 1kW system (Urban) 83MW

## Gambia

### Centralised

» 2012 Brikama 16MW, Batokunku 1MW

» 2014 Biomass 7MW, Bulk Wind (30% CF) 5MW, Solar PV (utility) 11MW

» 2015 CCGT 60MW, Biomass 6MW, Solar PV (utility) 5MW

» 2016 Solar PV (utility) 15MW

» 2019 Solar PV (utility) 3MW

» 2021 Kaleta(OMVG)partGambie12% 1MW, Solar PV (utility) 2MW

» 2022 Kaleta(OMVG)partGambie12% 5MW, Solar PV (utility) 1MW

» 2023 Kaleta(OMVG)partGambie12% 5MW, Solar PV (utility) 1MW

» 2024 Kaleta(OMVG)partGambie12% 6MW, Solar PV (utility) 1MW

» 2025 Kaleta(OMVG)partGambie12% 6MW, Solar PV (utility) 1MW

» 2026 Kaleta(OMVG)partGambie12% 6MW, Solar PV (utility) 1MW

» 2027 Kaleta(OMVG)partGambie12% 1MW, FelloSounga(OMVG)partGambie12% 9MW, Solar PV (utility) 2MW

» 2028 Solar PV (utility) 2MW, Solar thermal no storage 22MW

» 2029 Solar thermal no storage 23MW

» 2030 Solar thermal no storage 31MW

### De-Centralised

- 2012 Diesel/Gasoline 1kW system (Urban) 6MW
- 2013 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 7MW
- 2014 Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 3MW
- 2015 Small Hydro 1MW
- 2016 Small Hydro 2MW
- 2017 Diesel/Gasoline 1kW system (Urban) 1MW
- 2018 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2019 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2020 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 2MW
- 2021 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2022 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 7MW
- 2023 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 7MW
- 2024 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 4MW
- 2025 Diesel/Gasoline 1kW system (Urban) 1MW
- 2026 Diesel/Gasoline 1kW system (Urban) 1MW
- 2027 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 2MW
- 2028 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 2MW
- 2029 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 2MW
- 2030 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 2h Battery (roof top - rural) 4MW, Rooftop PV with 1h Battery 20MW

## Ghana

### Centralised

- 2012 Aboadze-T3 phase-1 120 MW, Tema-T1 110 MW, 10 MW
- 2013 Sunon Asogli phase-2 327 MW, Bui 342 MW
- 2014 Aboadze-T2 330 MW, 50 MW, Bulk Wind (30% CF) 9 MW
- 2015 Tema-T1 220 MW, 100 MW, Aboadze T4 (WAPP) 400 MW
- 2022 Biomass 1 MW
- 2023 Biomass 393 MW, Solar PV (utility) 204 MW
- 2024 Biomass 373 MW, Solar PV (utility) 500 MW
- 2025 Solar PV (utility) 359 MW
- 2026 Biomass 223 MW, Solar PV (utility) 61 MW
- 2027 Hemang 93 MW, OCGT 114 MW, Biomass 10 MW, Solar PV (utility) 55 MW

- 2028 OCGT 235 MW, Solar PV (utility) 65 MW
- 2029 OCGT 255 MW, Solar PV (utility) 67 MW
- 2030 OCGT 143 MW, Solar PV (utility) 12 MW

### De-Centralised

- 2014 Small Hydro 1 MW, Diesel/Gasoline 1 kW system (Urban) 118 MW
- 2015 Diesel/Gasoline 1 kW system (Urban) 63 MW
- 2016 Diesel/Gasoline 1 kW system (Rural) 6 MW, Diesel/Gasoline 1 kW system (Urban) 65 MW
- 2017 Diesel/Gasoline 1 kW system (Rural) 5 MW, Diesel/Gasoline 1 kW system (Urban) 65 MW
- 2018 Diesel/Gasoline 1 kW system (Rural) 6 MW, Diesel/Gasoline 1 kW system (Urban) 66 MW
- 2019 Diesel/Gasoline 1 kW system (Rural) 6 MW, Diesel/Gasoline 1 kW system (Urban) 66 MW
- 2020 Diesel/Gasoline 1 kW system (Rural) 4 MW, Diesel/Gasoline 1 kW system (Urban) 41 MW
- 2021 Diesel/Gasoline 1 kW system (Rural) 3 MW, Diesel/Gasoline 1 kW system (Urban) 23 MW
- 2022 Diesel/Gasoline 1 kW system (Rural) 3 MW, PV with 1h Battery (rooftop - rural) 9 MW, Diesel/Gasoline 1 kW system (Urban) 24 MW
- 2023 Diesel/Gasoline 1 kW system (Rural) 4 MW, PV with 1h Battery (rooftop - rural) 1 MW, Diesel/Gasoline 1 kW system (Urban) 25 MW
- 2024 Diesel/Gasoline 1 kW system (Rural) 4 MW, PV with 1h Battery (rooftop - rural) 2 MW, Diesel/Gasoline 1 kW system (Urban) 91 MW
- 2025 Diesel/Gasoline 1 kW system (Rural) 5 MW, Diesel/Gasoline 1 kW system (Urban) 107 MW
- 2026 Diesel/Gasoline 1 kW system (Rural) 11 MW, PV with 1h Battery (rooftop - rural) 1 MW, Diesel/Gasoline 1 kW system (Urban) 110 MW
- 2027 PV with 1h Battery (rooftop - rural) 94 MW, Diesel/Gasoline 1 kW system (Urban) 111 MW
- 2028 Diesel/Gasoline 1 kW system (Rural) 19 MW, PV with 2h Battery (rooftop - rural) 35 MW, Diesel/Gasoline 1 kW system (Urban) 106 MW
- 2029 Diesel/Gasoline 1 kW system (Rural) 10 MW, PV with 2h Battery (rooftop - rural) 62 MW, Diesel/Gasoline 1 kW system (Urban) 102 MW
- 2030 PV with 2h Battery (rooftop - rural) 87 MW, Diesel/Gasoline 1 kW system (Urban) 1 MW, Rooftop PV with 1h Battery 604 MW

## Guinea

### Centralised

- 2012 Tombo 3 (Rehab.) 2012 66MW
- 2013 Tombo 3 (Rehab.) 2013 35MW
- 2014 Maneah  126MW, Biomass 20MW

- 2015 Baneah (Rehab.) 5MW, Donkéa (Rehab.) 15MW, GrandesChutes (Rehab.) 27MW, Kaleta(OMVG)partGuinée40% 240MW, Biomass 21MW
- 2016 Biomass 22MW, Solar PV (utility) 184MW
- 2019 DAMEnvisagée 586MW, Solar PV (utility) 6MW
- 2020 DAMEnvisagée 586MW
- 2021 DAMEnvisagée 586MW
- 2022 DAMEnvisagée 586MW
- 2023 DAMEnvisagée 586MW
- 2026 Solar PV (utility) 127MW
- 2027 Solar PV (utility) 5MW
- 2028 Solar PV (utility) 5MW
- 2029 Solar PV (utility) 5MW
- 2030 Solar PV (utility) 4MW

### De-Centralised

- 2010 Diesel/Gasoline 1kW system (Urban) 4MW
- 2011 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2014 Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 6MW
- 2015 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 20MW
- 2016 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 10MW
- 2017 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 6MW
- 2018 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 6MW
- 2019 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 10MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2020 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 15MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2021 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 7MW
- 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2024 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 7MW
- 2025 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 1MW
- 2026 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW
- 2027 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 7MW
- 2028 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 7MW
- 2029 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 7MW
- 2030 Diesel/Gasoline 1kW system (Rural) 6MW, Small Hydro 9MW

## Guinea-Bissau

### Centralised

- 2012 Bissau  15MW
- 2013 Solar PV (utility) 6MW
- 2014 OCGT 4MW, Biomass 1MW
- 2015 CCGT 17MW, Biomass 2MW
- 2016 CCGT 43MW, Biomass 2MW, Solar PV (utility) 17MW
- 2017 Biomass 2MW
- 2018 Kaleta(OMVG)partGuinéeBissau8% 2MW, Biomass 2MW, Solar PV (utility) 4MW
- 2019 Kaleta(OMVG)partGuinéeBissau8% 3MW, OCGT 4MW, Biomass 2MW, Solar PV (utility) 2MW
- 2020 OCGT 51MW, Biomass 2MW, Solar PV (utility) 17MW
- 2021 OCGT 7MW, Biomass 2MW, Solar PV (utility) 2MW
- 2022 OCGT 1MW, Biomass 2MW, Solar PV (utility) 1MW
- 2023 OCGT 1MW, Biomass 3MW, Solar PV (utility) 1MW
- 2024 OCGT 2MW, Biomass 3MW, Solar PV (utility) 1MW
- 2025 OCGT 2MW, Biomass 3MW, Solar PV (utility) 1MW
- 2026 OCGT 2MW, Biomass 3MW, Solar PV (utility) 1MW
- 2027 Biomass 3MW, Solar PV (utility) 1MW, Solar thermal no storage 6MW
- 2028 Biomass 4MW, Solar PV (utility) 1MW, Solar thermal no storage 6MW
- 2029 Biomass 2MW, Solar PV (utility) 2MW, Solar thermal no storage 16MW
- 2030 Solar PV (utility) 1MW, Solar thermal no storage 16MW

### De-Centralised

- 2010 Diesel/Gasoline 1kW system (Urban) 3MW
- 2011 Diesel/Gasoline 1kW system (Urban) 4MW
- 2013 Solar PV (roof top) 1MW
- 2014 Small Hydro 1MW
- 2016 Small Hydro 1MW
- 2019 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 4MW
- 2020 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 1h Battery (roof top - rural) 2MW, Diesel/Gasoline 1kW system (Urban) 5MW
- 2021 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 1h Battery (roof top - rural) 2MW, Diesel/Gasoline 1kW system (Urban) 6MW
- 2022 PV with 1h Battery (roof top - rural) 2MW, Diesel/Gasoline 1kW system (Urban) 1MW

- 2023 PV with 1h Battery (roof top - rural) 2MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2024 PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2025 PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2026 PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2027 PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2028 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 1h Battery (roof top - rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2029 Diesel/Gasoline 1kW system (Urban) 6MW
- 2030 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 2h Battery (roof top - rural) 2MW, Diesel/Gasoline 1kW system (Urban) 6MW

## Liberia

### Centralised

- 2011 Bushrod 10MW
- 2013 Bushrod 2 40MW, Kakata (Buchanan) 35MW
- 2014 OCGT 33MW, Biomass 1MW, Solar PV (utility) 37MW
- 2015 MountCoffee(+Viareservoir) 66MW, CCGT 70MW, Biomass 2MW
- 2016 OCGT 5MW, Biomass 2MW, Solar PV (utility) 52MW
- 2017 SaintPaul -1B 78MW, SaintPaul-2 120MW
- 2024 Solar PV (utility) 4MW
- 2025 Solar PV (utility) 1MW
- 2026 Solar PV (utility) 1MW
- 2027 Solar PV (utility) 1MW
- 2028 Solar PV (utility) 1MW
- 2029 Solar PV (utility) 1MW
- 2030 Solar PV (utility) 1MW

### De-Centralised

- 2011 Diesel/Gasoline 1kW system (Urban) 2MW
- 2012 Diesel/Gasoline 1kW system (Urban) 4MW
- 2013 Solar PV (roof top) 1MW
- 2014 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 3MW, Solar PV (roof top) 1MW
- 2015 Small Hydro 1MW, Solar PV (roof top) 2MW
- 2016 Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 2MW, Solar PV (roof top) 2MW
- 2017 Small Hydro 2MW

- 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2019 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2020 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 2MW
- 2021 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 2MW
- 2022 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 4MW
- 2023 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2025 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2026 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2027 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2028 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW
- 2029 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 4MW
- 2030 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 2MW

## Mali

### Centralised

- 2011 SIKASSO (CO) 9MW, Balingue BID 60MW
- 2012 KOUTIALA (CI) 4MW, VICA BOOT 30MW, Albatros BOOT 92MW, Mopti SOLAR 10MW
- 2013 27MW
- 2014 Sotuba2 6MW
- 2015 Kenié 34MW
- 2017 Gouina(OMVS)partMali45% 63MW
- 2018 DAMEnvisagée 303MW
- 2022 Solar PV (utility) 153MW
- 2024 Solar PV (utility) 14MW
- 2025 Solar PV (utility) 7MW
- 2026 Solar PV (utility) 7MW
- 2027 Solar PV (utility) 7MW
- 2028 Solar PV (utility) 7MW
- 2029 Solar PV (utility) 8MW
- 2030 Solar PV (utility) 6MW

### De-Centralised

- 2011 Diesel/Gasoline 1kW system (Rural) 1MW

- 2012 Diesel/Gasoline 1kW system (Urban) 4MW
- 2013 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 10MW
- 2014 Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 33MW
- 2015 Small Hydro 2MW
- 2016 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 11MW
- 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2019 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 1MW
- 2020 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 6MW
- 2021 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW
- 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW
- 2023 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 5MW
- 2024 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW
- 2025 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW
- 2026 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 6MW
- 2027 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW
- 2028 Diesel/Gasoline 1kW system (Rural) 3MW
- 2029 Diesel/Gasoline 1kW system (Rural) 3MW
- 2030 Diesel/Gasoline 1kW system (Rural) 3MW

## Niger

### Centralised

- 2011 Niamey 2 15MW
- 2012 TAG Niamey 2 10MW, Dossou 2MW, Tillabery 2MW, Gaya 1MW, Goudel 12MW
- 2013 Zinder 8MW
- 2014 Wind 30MW, Diesel Centralised 16MW, Biomass 21MW, Bulk Wind (30% CF) 71MW
- 2015 Kandadji 130MW, Bulk Wind (30% CF) 14MW
- 2016 Dyodyonga 26MW, Bulk Wind (30% CF) 5MW
- 2017 Bulk Wind (30% CF) 5MW
- 2018 Supercritical coal 111MW
- 2022 Bulk Wind (30% CF) 26MW
- 2023 Bulk Wind (30% CF) 6MW
- 2024 Bulk Wind (30% CF) 6MW
- 2027 Bulk Wind (30% CF) 17MW, Solar PV (utility) 89MW

- 2028 Bulk Wind (30% CF) 6MW, Solar PV (utility) 3MW
- 2029 Bulk Wind (30% CF) 5MW, Solar PV (utility) 3MW
- 2030 Bulk Wind (30% CF) 4MW, Solar PV (utility) 2MW

### De-Centralised

- 2010 Diesel 100 kW system (industry) 1MW
- 2011 Diesel 100 kW system (industry) 4MW
- 2012 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 11MW
- 2013 Diesel/Gasoline 1kW system (Urban) 13MW
- 2014 Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 9MW
- 2016 Small Hydro 2MW
- 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2019 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 1MW
- 2020 Small Hydro 2MW
- 2021 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW
- 2023 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2025 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 1MW
- 2026 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2027 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 8MW
- 2028 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 8MW
- 2029 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 8MW
- 2030 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 5MW

## Nigeria

### Centralised

- 2011 GT 2011 2953MW
- 2012 GT 2012 4126MW
- 2013 GT 2013 1452MW
- 2015 CCGT 1500MW, Bulk Wind (30% CF) 363MW
- 2016 CCGT 1600MW

- 2017 Mambilla 2,600MW, CCGT 1,700MW
- 2018 Zungeru  700MW, CCGT 1,800MW
- 2019 CCGT 1,900MW
- 2020 CCGT 1,256MW, Hydro 1,000MW
- 2021 CCGT 241MW, Hydro 1,000MW
- 2022 CCGT 25MW, Hydro 1,000MW
- 2023 Hydro 1,000MW
- 2024 Hydro 1,000MW
- 2025 Hydro 1,000MW
- 2026 Hydro 842MW

### De-Centralised

- 2011 Diesel/Gasoline 1kW system (Rural) 7MW, Diesel/Gasoline 1kW system (Urban) 1,113MW
- 2012 Diesel/Gasoline 1kW system (Rural) 45MW, Diesel/Gasoline 1kW system (Urban) 557MW
- 2013 Diesel/Gasoline 1kW system (Rural) 47MW, Diesel/Gasoline 1kW system (Urban) 47MW
- 2014 Small Hydro 215MW, Diesel/Gasoline 1kW system (Urban) 50MW
- 2015 Small Hydro 33MW, Diesel/Gasoline 1kW system (Urban) 48MW
- 2016 Small Hydro 116MW, Diesel/Gasoline 1kW system (Urban) 67MW
- 2017 Diesel/Gasoline 1kW system (Rural) 26MW, Small Hydro 139MW, Diesel/Gasoline 1kW system (Urban) 66MW
- 2018 Diesel/Gasoline 1kW system (Rural) 28MW, Small Hydro 105MW, Diesel/Gasoline 1kW system (Urban) 64MW
- 2019 Diesel/Gasoline 1kW system (Rural) 31MW, Small Hydro 57MW, Diesel/Gasoline 1kW system (Urban) 62MW
- 2020 Diesel/Gasoline 1kW system (Rural) 31MW, Small Hydro 110MW, Diesel/Gasoline 1kW system (Urban) 43MW
- 2021 Diesel/Gasoline 1kW system (Rural) 46MW, Small Hydro 141MW, Diesel/Gasoline 1kW system (Urban) 1,239MW
- 2022 Diesel/Gasoline 1kW system (Rural) 85MW, Small Hydro 222MW, Diesel/Gasoline 1kW system (Urban) 655MW
- 2023 Diesel/Gasoline 1kW system (Rural) 90MW, Small Hydro 168MW
- 2024 Diesel/Gasoline 1kW system (Rural) 48MW, Small Hydro 184MW
- 2025 Diesel/Gasoline 1kW system (Rural) 52MW, Small Hydro 83MW
- 2026 Diesel/Gasoline 1kW system (Rural) 54MW, Small Hydro 195MW
- 2027 Diesel/Gasoline 1kW system (Rural) 82MW, Small Hydro 205MW
- 2028 Diesel/Gasoline 1kW system (Rural) 88MW, Small Hydro 215MW
- 2029 Diesel/Gasoline 1kW system (Rural) 93MW, Small Hydro 224MW
- 2030 Diesel/Gasoline 1kW system (Rural) 74MW, Small Hydro 156MW

## Senegal

### Centralised

- 2011 Location 150MW
- 2012 belair 30MW
- 2013 Felou(OMVS)partSénégal15% 15MW
- 2014 ross betio  30MW, Biomass 62MW, Bulk Wind (30% CF) 232MW
- 2015 Biomass 66MW, Bulk Wind (30% CF) 29MW, Solar PV (utility) 157MW
- 2016 Sendou  250MW, Biomass 66MW, Bulk Wind (30% CF) 38MW
- 2017 Sambangalou(OMVG)partSénégal40% 51MW, Gouina(OMVS)partSénégal25% 35MW, Bulk Wind (30% CF) 15MW
- 2018 Biomass 53MW, Bulk Wind (30% CF) 15MW
- 2019 Biomass 3MW, Bulk Wind (30% CF) 16MW
- 2020 Bulk Wind (30% CF) 18MW
- 2021 Bulk Wind (30% CF) 21MW, Solar PV (utility) 74MW
- 2022 Bulk Wind (30% CF) 20MW, Solar PV (utility) 12MW
- 2023 Bulk Wind (30% CF) 21MW, Solar PV (utility) 13MW
- 2024 Bulk Wind (30% CF) 23MW, Solar PV (utility) 14MW
- 2025 Bulk Wind (30% CF) 24MW, Solar PV (utility) 14MW
- 2026 Bulk Wind (30% CF) 25MW, Solar PV (utility) 15MW
- 2027 Bulk Wind (30% CF) 25MW, Solar PV (utility) 15MW
- 2028 Kaleta(OMVG)partSénégal40% 1MW, Bulk Wind (30% CF) 27MW, Solar PV (utility) 16MW, Solar thermal no storage 142MW
- 2029 Bulk Wind (30% CF) 30MW, Solar PV (utility) 18MW, Solar thermal no storage 251MW
- 2030 Kaleta(OMVG)partSénégal40% 3MW, Bulk Wind (30% CF) 26MW, Solar PV (utility) 16MW, Solar thermal no storage 123MW

### De-Centralised

- 2010 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 3MW
- 2012 Diesel/Gasoline 1kW system (Urban) 49MW
- 2013 Diesel/Gasoline 1kW system (Rural) 3MW, Diesel/Gasoline 1kW system (Urban) 13MW
- 2014 Small Hydro 11MW, Diesel/Gasoline 1kW system (Urban) 8MW
- 2015 Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 15MW
- 2016 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 10MW, Diesel/Gasoline 1kW system (Urban) 18MW
- 2017 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 8MW
- 2018 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 8MW
- 2019 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 8MW
- 2020 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 7MW

» 2021 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 5MW

» 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 54MW

» 2023 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 18MW

» 2024 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 13MW

» 2025 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 20MW

» 2026 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 8MW

» 2027 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 9MW, Diesel/Gasoline 1kW system (Urban) 26MW

» 2028 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 23MW

» 2029 Diesel/Gasoline 1kW system (Rural) 5MW

» 2030 Diesel/Gasoline 1kW system (Rural) 6MW, Diesel/Gasoline 1kW system (Urban) 24MW

## Sierra Leone

### Centralised

» 2013 Diesel Centralised 3MW, Solar PV (utility) 16MW

» 2014 OCGT 120MW, Biomass 6MW, Solar PV (utility) 41MW

» 2015 Bumbuna2 40MW, CCGT 111MW, Biomass 6MW, Solar PV (utility) 4MW

» 2016 Biomass 6MW, Solar PV (utility) 35MW

» 2017 Bumbuna3(Yiben) 90MW, Bumbuna4&5 95MW, Biomass 7MW, Solar PV (utility) 33MW

» 2018 Energeon 100MW, Addax  15MW, Biomass 7MW

» 2019 Biomass 8MW, Solar PV (utility) 79MW

» 2020 Benkongor1 35MW, Biomass 8MW, Solar PV (utility) 41MW

» 2021 Biomass 9MW, Solar PV (utility) 1MW

» 2022 Benkongor2 80MW

» 2024 Solar PV (utility) 9MW

» 2025 Benkongor3 86MW, Solar PV (utility) 1MW

» 2026 DAMEnvisagée 323MW, Solar PV (utility) 1MW

» 2027 Solar PV (utility) 1MW

» 2028 Solar PV (utility) 1MW

» 2029 Solar PV (utility) 1MW

### De-Centralised

» 2011 Diesel 100kW system (industry) 38MW, Diesel/Gasoline 1kW system (Urban) 7MW

» 2012 Diesel 100kW system (industry) 1MW, Diesel/Gasoline 1kW system (Urban) 7MW

- 2013 Diesel 100 kW system (industry) 37MW, Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 10MW, Solar PV (roof top) 5MW
- 2014 Small Hydro 4MW, Solar PV (roof top) 6MW
- 2015 Small Hydro 1MW, Solar PV (roof top) 1MW
- 2016 Small Hydro 6MW, Solar PV (roof top) 6MW
- 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2019 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Solar PV (roof top) 8MW
- 2020 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 8MW, Solar PV (roof top) 8MW
- 2021 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 8MW
- 2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW
- 2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 1MW
- 2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 8MW
- 2025 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2026 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 4MW
- 2027 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW
- 2028 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW
- 2029 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 2MW

## Togo/Benin

### Centralised

- 2011 CAI 80MW
- 2012 IPP_SOLAR 20MW
- 2013 IPP_WIND 20MW, IPP_THERMAL 54MW
- 2014 OCGT 39MW, Biomass 46MW
- 2015 MariaGleta 450MW
- 2017 Adjarala 147MW
- 2023 Biomass 51MW, Solar PV (utility) 171MW
- 2024 Biomass 92MW, Solar PV (utility) 113MW
- 2026 Biomass 72MW, Solar PV (utility) 39MW
- 2027 Biomass 92MW, Solar PV (utility) 21MW
- 2028 Biomass 99MW, Solar PV (utility) 22MW

- 2029 Biomass 125MW, Solar PV (utility) 23MW
- 2030 Biomass 124MW, Solar PV (utility) 18MW

## De-Centralised

- 2010 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 4MW
- 2011 Diesel 100 kW system (industry) 9MW, Diesel/Gasoline 1kW system (Rural) 2MW, Diesel/Gasoline 1kW system (Urban) 47MW
- 2012 Diesel/Gasoline 1kW system (Urban) 70MW
- 2014 Small Hydro 17MW, Diesel/Gasoline 1kW system (Urban) 6MW
- 2016 Small Hydro 2MW
- 2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
- 2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
- 2019 Diesel/Gasoline 1kW system (Rural) 1MW
- 2020 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 11MW
- 2021 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 55MW
- 2022 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 79MW
- 2023 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 9MW
- 2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 1MW
- 2025 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 13MW
- 2026 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 13MW
- 2027 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW

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