EREP: Prospects for Renewable Power in the Economic Community of West African States

IRENA

Contents

1 Introduction

Africa needs to raise its electricity supply significantly to enhance energy access for its growing population and provide the necessary energy for economic growth. Africa has great domestic renewable energy potentials, 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 impacts on environment. Long term vision is required to make best use of available domestic resources, given the long-lasting nature of energy infrastructure. Local energy planners need to develop such vision in quantitative forms and analyze alternatives based on appropriate data and planning tools. IRENA's scenario and strategy project aims at assisting IRENA's member countries with enhancing capacity in such energy planning. The project's initial work *'Scenarios and Strategies for Africa*' (IRENA 2012a) 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 a communique was announced by Ministers of Energy and heads of delegates of African countries, recognizing the IRENA's role in promoting renewable energy for accelerating Africa's development (IRENA 2011a).

In response IRENA has taken up a number of areas of research to provide solid factual basis to support policy decision making. This work presented here is to derive cost competitive electricity investment options in the West Africa to achieve long-term energy sector policy objectives, while taking into account differences among the countries and interconnection among them, and to explore the potential role of renewable energy technologies.

The West African Power Pool (WAPP) has a key role to play in energy planning to improve reliable, affordable, low cost power supply in West Africa – a region which has an exceptionally low per capita electricity demand. For the coming two decades, it is projected that demand may increase ten-fold as the economic activities increase and universal access is achieved. This raises important questions regarding the optimal power supply mix. Worldwide the share of renewables in power capacity additions has reached more than 50%. Electricity from hydro, wind and solar PV sources has reached global capacity addition levels of 30, 45 and 28 GW, respectively, in 2011. It is a fact that West Africa has significant renewable energy potentials. The challenge is how to use these potentials to meet future electricity demand.

A first question is how electricity supply in the region should be expanded: centralized grids, minigrid or offgrid solutions. New renewable electricity solutions have emerged for minigrids and offgrid electricity supply. A second question is if centralized grids are expanded what form of electricity supply is preferred: fossil or renewable energy. The quality of the renewable energy resource in the region is exceptionally high. However at the same time significant oil and gas resources exist.

Operating an electricity grid is difficult because electricity cannot be stored at acceptable cost except in the case of pumped storage hydropower systems. Moreover if supply falls short of demand, the power system collapses and outages occur, a frequent phenomenon in the region. Because of the long life span of a power plant, decisions now will lock in infrastructure for many decades. At the same time demand projections are highly uncertain, fossil fuel prices fluctuate and technological progress makes renewables more attractive. Planning using appropriate energy planning tools must account for all these factors.

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 analyzed and evaluated from economic and technical perspectives. The economic evaluation of different scenarios combining different policy actions and uncertainties was done using a power system optimization tool. The WAPP Master Plan uses these scenarios to identify priority investment projects from an economic perspective.

Against this background and in order to respond to the mandate mentioned at the outset, IRENA has also been developing a model for the ECOWAS (Economic Community of West African States) region, based on data in the public domain, IRENA and its partner organizations. The model is called EREP, the *ECOWAS Renewable Energy Planning* tool. The aim is to transfer EREP to energy planners in IRENA member countries, so that they can use it for exploring alternative scenarios for national and regional power sector development. EREP is a power system optimization tool, similar to the one used to develop the scenarios in the WAPP Master Plan.

EREP covers the following countries: Burkina Faso, Cote d'Ivoire, Gambia, Ghana, Guinea, Guinea-Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone, and Togo/Benin.

IRENA has a completed version of the WAPP model that is ready for distribution. This report presents the preliminary findings of an analysis of renewable deployment using the model demonstrating the use of the model. It focuses on the economic potential for renewable power supply in the region's power supply mix. As many countries in the region stand at crossroads on how to provide power to its people and economy, this is a timely exercise. Initial results from EREP suggest that up to 54% of the power supply in 2030 in the region could be supplied by renewable energy technologies in an economically competitive way. This result is preliminary as the model structure and the input data assumptions, which determine the outcomes of the model, are to be validated through a consultation with the member states in the region.

2 Overview of Methodology

EREP was developed using a modeling platform called MESSAGE. MESSAGE is a dynamic, bottom-up, multi-year energy system model applying linear and mixed-integer optimization techniques. The modelling platform was originally developed at the International Institute of Applied System Analysis (IIASA), but more recently has been further enhanced by the International Atomic Energy Agency (IAEA). The modelling platform is the framework within which the actual model is developed.

The MESSAGE model framework consists of database which needs to be populated with energy demand and load projection, economic and technical parameters of energy resources and energy supply options, including power plants, transmission and distribution lines, and electricity trades, and information regarding the existing capital stock and remaining life span. IRENA developed EREP model by populating the database, configuring it to replicate existing power infrastructure in each country, and setting up a few “scenarios” in which alterative visions on the future development of power system and factors influencing it are quantified. EREP builds on the earlier work done by the IAEA. The input assumptions are mostly derived from the WAPP Master Plan input data. It considers four types of power generation options, existing power plants, power plants to be commissioned, site specific power plants under consideration, and non-site specific generic power plants. Decisions about investment and operation of plants under consideration and generic plants are a result of the least-cost optimization in MESSAGE. The model reports on investment and production mix of technologies and fuels that achieve the least-cost power system configuration to meet a given power demand. Economic and environmental implications associated with the identified least-cost power systems can be easily calculated using the model. In some cases, some of the social implications can also be assessed.

The model developed by the IAEA was further enhanced by IRENA in two regards; first additional aspects were included that are essential for proper assessment of renewable energy technology deployment, and second the latest findings for renewable energy technology potential and cost development was considered, based on a series of IRENA studies for Africa. To better reflect the role of decentralized power options, for which renewables can offer a significant cost advantage over fossil based options, the power demand was split into three categories, industrial, urban and rural electricity use. This is important as the shape of the load curve and the connection to the grid differs markedly. Different distributed generation options are available to each category. The set of renewable energy supply options was expanded and significantly refined. The latest technology cost data and capacity factor data were used, based on IRENA cost competitiveness and technology assessment studies. Data on the quantity and quality of renewable energy resources was updated and refined based on data collected in the framework of the IRENA-Clean Energy Ministerial Renewable Energy Atlas work.

In the EREP model, each country is modeled as a separate node inter-linked by transmission lines. Each node representing the power system of a single country is characterized as shown in Figure 1. Once the demand is specified, a technically feasible, least-cost power supply system that meet the given demand while satisfying all the constraints is computed by the model for the modeling period. The “least cost” is defined for the region as a whole, and for the entire modeling period.

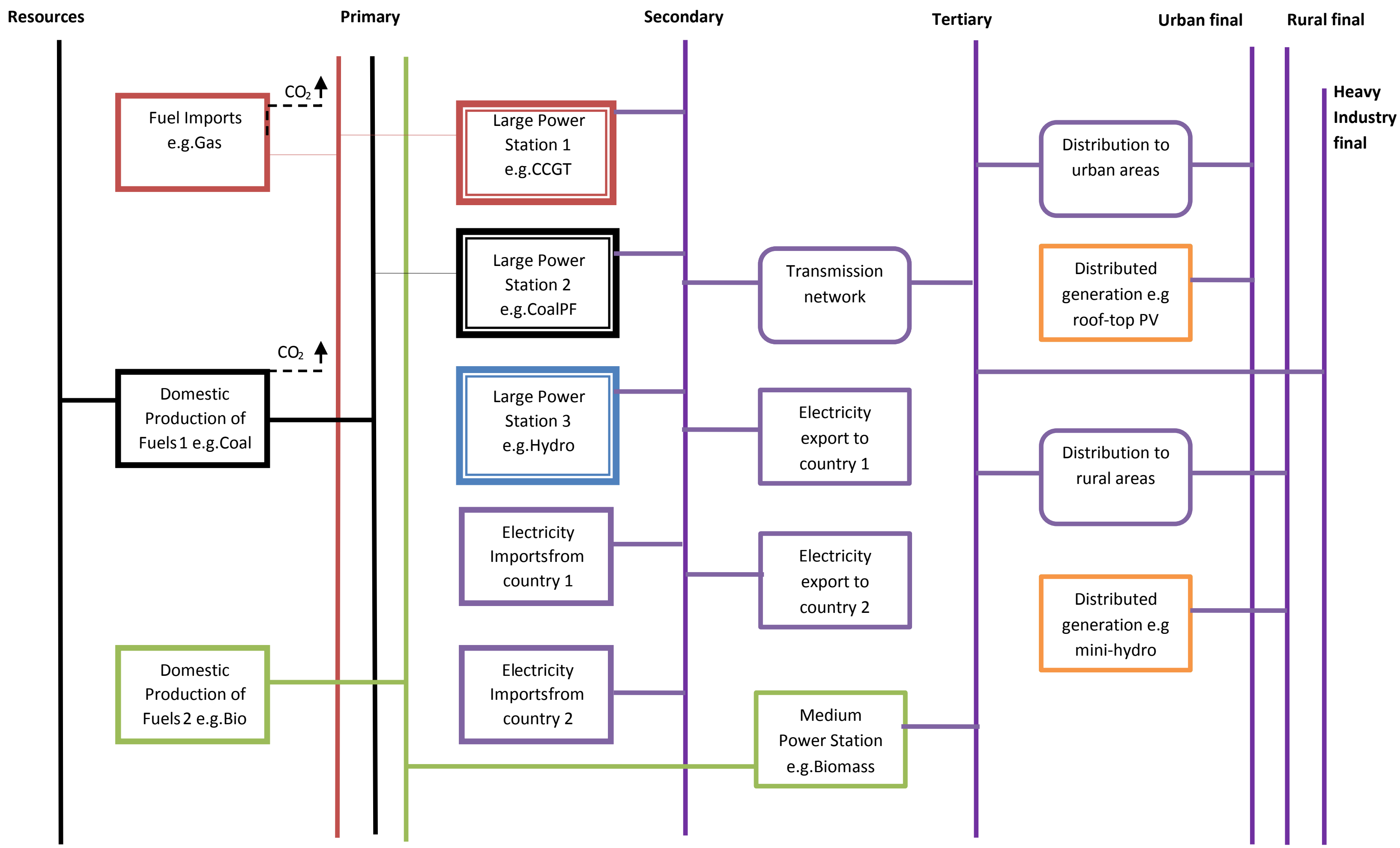

Figure 1 Country Power Sector Model Structure

3 Scenario Description

The strength of the modeling framework that has been deployed is that it allows for analysis of scenarios with a consistent and coherent set of assumptions for a very complex power system. These scenarios can inform policy makers in their development of robust strategies. The scenarios can be used to derive information on policy cost, technology and investment project priorities, financing needs and other key policy variables.

One reference scenario and three alternative scenarios have been assessed. The reference scenario was set up in a manner that is compatible with the WAPP Master Plan reference scenario but with mining demand included. The system optimized at the regional level, with electricity trade within the ECOWAS region allowed. Only the specific trans-border transmission projects currently under considerations are assumed to become available during the study period. Some important differences are:

- inclusion of decentralized electricity supply options,
- segregation of rural/urban/industrial electricity demand,
- updating of RE resource potentials and renewable energy technology cost data,
- 'dry-year' for hydro modeled for every year. The model employed in the Master Plan offers the possibility of some stochastic modelling of the hydro availability, which cannot be replicated with the current version of EREP.

A renewable energy policy scenario was setup in which cost reductions for renewable energy technologies due to anticipated technology learning are taken into account. The technology learning effects associated with the global expansion of capacity of renewable energy technologies have brought down the costs significantly in the past (IRENA, 2012b, c, d, e, f). The fossil fuel prices are escalated, and the Inga hydro power project in DRC (or Cameroon) takes off and some of the vast hydro resources in Central Africa become available to ECOWAS countries. Other implicit assumptions behind this scenario are that in addition to cost reduction due to technology learning, various policy measures, including streamlining the regulation and taxes, increasing the local contents of the equipment, resolving material supply bottleneck developed, also contribute to the cost reduction of renewable energy technologies.

Two variations of the renewable policy scenario were also defined:

1. No CA imports: options from the Central African region are excluded
2. Energy Security: import share limited to 25% of the total electricity demand for each country. Countries that already have higher than 25% share of import are modeled so that by 2030, the share gradually is reduced to 25%.

4 Model Assumptions

4.1 Overall Assumptions

Overall assumptions across all scenarios are as follows:

- The real discount rate applied is 10%, consistent with the assumption in WAPP Master Plan.
- The monetary unit is 2010 US$ and adjustments from data reported in US$ from other years are made using US GDP inflator from the World Bank (WB 2011).
- The study horizon spans from 2010 to 2050, with focus on 2010 – 2030.
- In order to capture the key features of electricity demand load pattern, the year is characterized by three seasons, namely pre-summer, summer, and post-summer. Pre-summer and summer days are characterized by 3 blocks of equal demand, namely: “day”, “night”, “evening”. Post-summer days are characterized with an additional block to capture the peak seen by the system.
- Penetration of intermittent renewable upstream of the transmission grid energy is limited to 10% of the total generation upstream of transmission for solar and 20% for wind to conservatively ensure the system stability.

4.2 Assumptions about Electricity Demand

The main source used for electricity demand projections (TWh), is the WAPP Master Plan: “Update of the ECOWAS Revised Master Plan for the Generation and Transmission of Electrical Eenrgy” (WAPP 2011). The report provides data up to 2025 upstream of Transmission, in some cases with mining projects handled separately. The demand projections considered in the reference scenario include the mining projects. The demand post 2025 is simply extrapolated from the growth projected by the ECOWAS study for the period 2020-2025. Figure 2 shows the evolution of the electricity demand upstream of transmission (secondary electricity demand), which is dominated by Nigeria. Projections for Guinea Bissau, Guinea, Sierra Leone, and Liberia include electricity demand for mining projects, which are projected to be up to a few times larger than the other demands. There are possibly other mining projects in the region that were not identified by the WAPP Master Plan e.g. gold mining in Burkina Faso, but those are not included in this analysis. Actual figures are given in Table 15 in appendix A.

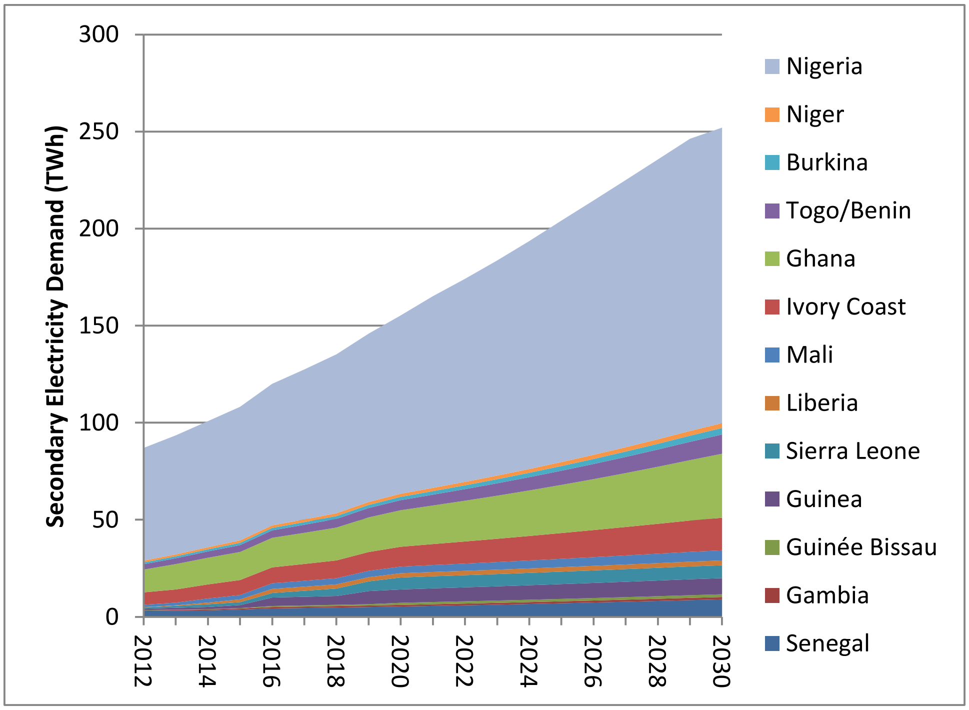

Figure 2 Secondary Electricity Demand Projections with Mining Projects

The demand was further broken down into “heavy industry”, “urban”, and “rural” categories as follows,

- ***Heavy industry*** (e.g. mining), which connects to generation at a high voltage and generally requires less transmission and no distribution infrastructure;
- ***Urban*** residential, commercial, and small industries, which are connected to generation via relatively more transmission and distribution infrastructure;
- ***Rural*** residential and commercial, which require even more transmission and distribution infrastructure.

A full sector bottom analysis is required to project the sectoral demand, but is beyond the scope of this work. A simpler and cruder approach was adopted, which can be described as follows:

- The starting point for the electricity demand projections are the Master Plan projections at utility (secondary) level.
- The energy balances were then used to split base year consumption into "heavy industry" and "other", with care taken to adjust for difference in losses, assuming that heavy industry has lower losses.
- The evolution of the split over time was roughly estimated, assuming that some small share of the electricity demand will come from rural areas.
- In some countries, the Master Plan explicitly provided the electricity demand for certain mining or industrial projects. For these countries, this additional demand was completely allocated to “heavy industry” with the rest being allocated to “urban” and “rural” sectors.

Figure 3 shows the aggregated electricity demand in the region by the three categories.

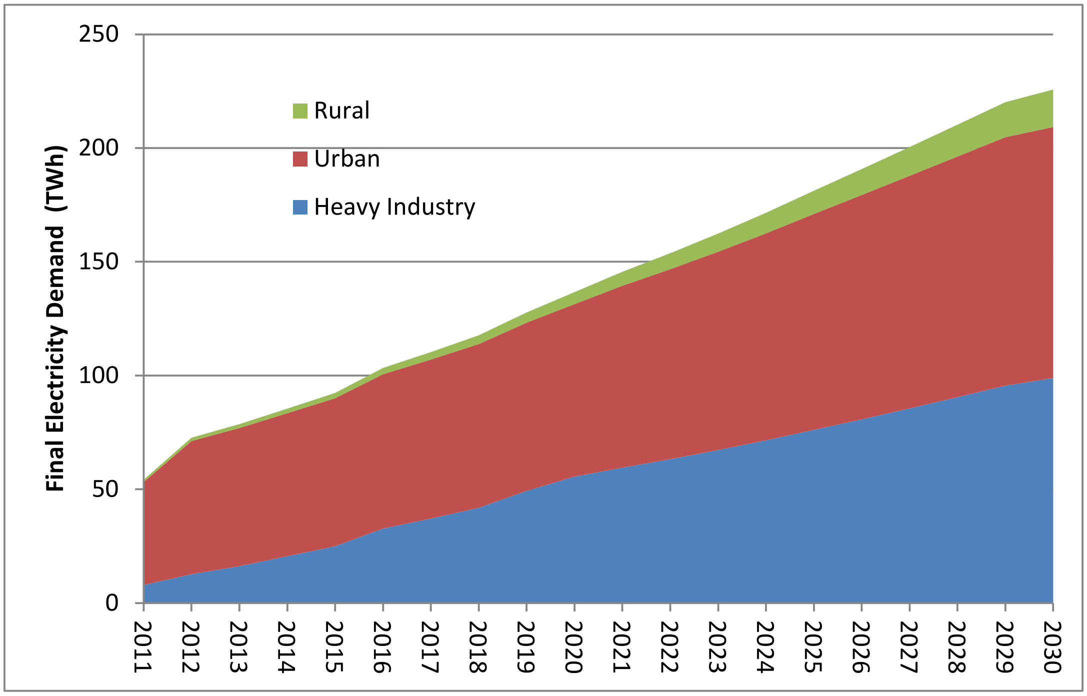

Figure 3: The total electricity demand by sector

Each demand segment is characterized by a different load profile which is assumed common to all the countries. Load profile for each demand segment is defined with shares of demand in each season and shares of demand in each day-block (day, evening, night). Since different countries have different shares of these three segments, the resulting load profile for the total demand are specific to each country. They are described in the appendix A.

4.3 Assumptions on local transmission and distribution

Three different levels of cost and losses are defined for the three identified customer groupings to account for the different levels of transmission and distribution infrastructure required and the implications. Losses are also set differently and kept constant over time.

Table 1 Assumptions for Transmission and Distribution infrastructure[1]

	Trans.&Dist Cost	Losses
	US cents/kwh	**%**
Heavy Industry	**1.5**	**7%**
Urban Residential/commercial/small industries	**5**	**15%**
Rural Residential/commercial	**10**	**20%**

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

Off-grid technologies do not require the transmission and distribution infrastructure, therefore there is no costs and losses associated with it.

4.4 Assumptions about Renewable Resource Potential

Large Hydro

The large-hydro potential is limited to the identified hydro sites in (WAPP 2011) and summarized in Table 2. A "dry-year" scenario is assumed for all hydro sites in all years within the modeling horizon. This underplays the role of hydro in the region but is considered conservative in view of the vulnerability of the region to drought years. A more comprehensive stochastic approach as done in (WAPP 2011) was not possible due to limitations of MESSAGE modeling platform. Detailed parameters for existing and planned hydro projects are given in Table 17, Table 18 and Table 19 in Appendix B.

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	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**

Non-Large-Hydro Renewable Energy Potential

Estimates for the non-large-hydro renewable resource potential are shown in Table 3. Estimates for solar is based on the Mines ParisTech dataset and wind data is based on the Vortex data set (9km resolution) as reported in (IRENA 2012a). This analysis possibly underestimates the potential given that it only considers 1% of suitable land area as being available for RE generation. The mini hydro data is based on (UNIDO/ ECREEE 2010) and the biomass data is based on (IRENA 2011b).

[2] In Nigeria there is 3,300 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.

Table 3 Non-Large-Hydro RE Potential Rough Estimates

	Mini Hydro	Solar CSP	Solar PV	Biomass	Wind 20%	Wind 30%
	MW	TWh	TWh	MW	MW	MW
Burkina	140	18.1	77.4	2,250	4,742	28.7
Cote d'Ivoire	242	2.21	103	1,530	491	0.0
Gambia	12	3.16	4.74	23.75	197	5.1
Ghana	1	2.29	76.4	1,133	691	9.1
Guinea	332	4.67	52.0	656	2.4	0.0
Guinea-Bissau	2	9.06	14.9	71	142	0.0
Liberia	1,000	0.00	6.67	459	0.0	0.0
Mali	67	36.2	79.1	1,031	2,195	0.0
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	1.97	15.0	166	0.0	0.0
Togo/Benin	336	0.00	51.6	957	551	0.0

4.5 Assumptions about Fuel Availability and Prices

For gas supply, three types of gases are assumed available; locally produced gas (in Nigeria, Ivory Coast, and Ghana), Nigerian gas supplied through Western African Gas Pipeline (in Ghana, Togo, and Benin), and imported LNG (other coastal countries).

For petro products, three types of fuels are distinguished, namely, heavy fuel oil (HFO), diesel (DDO), and light crude oil (LCO). Different prices are assumed for the petro products delivered to the coastal countries and to the inland countries.

For coal, local production of the coal is assumed available only in Nigeria and Niger and for all other coastal countries coal import option is assumed available. Inland countries other than Niger are assumed to have no domestic resource of coal and coal transport infrastructure and costs to them are assumed to be prohibitively expensive.

Base-year fossil fuel prices are based on the Master Plan (WAPP 2011). The fuel prices for gas, oil products, and coal in the base year in the Master Plan were derived from an assumption of OPEC oil price being 100 USD per bbl. For the future years, in the Renewable Scenario and its variations, it is assumed that price for oil products increase by 20% by 2020, and by 35% by 2030 compared to the base year. For gas prices, the escalation relative to 2010 value in 2020 and 2030 is 10% and 30% respectively. The domestic coal in Niger and Nigeria is set lower compared to the landed price in coastal countries. The domestic coal price was based on (Idrissa 2004). Note that the Master Plan does not distinguish between the price for locally produced coal for Niger and imported coal for other countries. As to biomass, its resource in the three inland countries Burkina, Niger and Mali are assumed to be scarce and the price is assumed higher.

The assumed price evolutions for fuels are summarized in Table 4.

Table 4 Fuel Price Projections

$/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
Light Crude Oil (delivered to the coast)	17.8	21.4	24.0
Light Crude Oil (delivered to the inland)	18.9	22.7	25.5
Gas Domestic	8.5	9.5	11
Gas Imported	11.0	12.3	14.2
Coal Domestic	3.0	3.3	3.5
Coal Imported	4.6	5.0	5.3
Biomass Free (Sugar Cane)	0.0	0.0	0.0
Biomass Not Free	1.5	1.5	1.5
Biomass Scarce	3.6	3.6	3.6

4.6 Assumptions about electricity generation options

Existing Thermal Generating Capacity

Existing thermal generation is based on (WAPP 2011), and is summarized in Table 5. Detailed parameters are given in Table 16 and Table 17 in Appendix B.

Table 5 Existing Thermal Generating Capacity

	Existing Capacity	Fuel Mix (in terms of capacity)
	MW	
Burkina	146	80% HFO, remainder diesel
Cote d'Ivoire	765	Gas open cycle
Gambia	49	Mainly HFO with some diesel
Ghana	865	Light crude and gas closed-cycle and some diesel and light crude open cycle
Guinea	19	HFO
Guinea-Bissau	4	Diesel generators
Liberia	13	Diesel generators
Mali	134	Diesel generators and open cycle, and some HFO generators
Niger	67	50% coal fired steam turbine and a third gas open cycle, remainder diesel generators
Nigeria	3,858	11% Diesel, remainder Gas
Senegal	444	Mainly HFO with some combined and open cycle turbines
Sierra Leone	44	Mainly HFO with some diesel generators

Togo/Benin	196	Some gas turbines, diesel and HFO generators

Future Power Generation Projects

Table 6 shows the summary of power generation projects under consideration as per (WAPP 2011). In our reference scenario, those committed are forced into the future energy system and those not yet committed are to be selected by the optimization process. Detailed tables are given in the appendix.

Table 6 Summary of Future Projects

MW	Oil	Coal	Gas	Hydro	Biomass	Wind	Solar
Burkina	120	-	-	60	-	-	40
Cote d'Ivoire	-	-	1,313	1,072	-	-	-
Gambia	16	-	-	68	-	1	-
Ghana	100	-	2,265	661	-	150	10
Guinea	227	-	-	3,346	-	-	-
Guinea-Bissau	15	-	-	14	-	-	-
Liberia	50	-	-	967	35	-	-
Mali	332	-	-	434	33	-	40
Niger	32	200	18	279	-	30	50
Nigeria	-	-	13,581	3,300	-	-	-
Senegal	540	1,000	-	530	30	225	8
Sierra Leone	-	-	-	755	115	-	5
Togo/Benin	-	-	630	357	-	20	35
Total	1,432	1,200	17,807	11,840	213	426	188

Generic Renewable Power Generation Technology

In the WAPP model, the demand is first met by the existing technologies and committed projects. The reminder of the demand is met by site specific projects and/or generic power generation technologies. The generic power generation technologies are modeled without a specific reference to any unit size. Certain technologies are assumed to provide electricity only via the grid, others are assumed to provide on-site electricity.

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

- **Small or mini hydro** to supply the rural demand
- **On-shore wind** connected upstream of transmission. Two wind regimes are considered, namely 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 onto the grid (upstream of transmission).

- **Utility PV** or PV farms managed by the utility and connected upstream of transmission. They were modeled to only produce electricity during the day.
- **Distributed or roof-top Solar PV** to supply either urban residential, commercial and small industries, or rural residential and commercial. They were modeled to only produce electricity during the day.
- **Distributed or roof-top Solar PV with storage** in the form of a battery, for slightly extended use beyond daylight hours. They can produce some electricity in the evening
- **Solar CSP no Storage** medium to large scale concentrated solar connected upstream of transmission
- **Solar CSP with Storage** medium to large scale concentrated solar with thermal storage. It can produce electricity during the day and in the evening (see appendix for time of day specification of solar plants)

The evolution of the investment cost for renewable options used in the renewable scenario are shown in Figure 4. The learning rates anticipated are based on increased global installed capacity in those technologies. What is assumed here is more aggressive reduction of costs, assuming that they are achieved as a result of governments and the private sector in the region actively looking for opportunities to raise the local content, more stream lined regulations and taxation regimes, resolved bottlenecks in materials supply including transportation problems such as roadblocks and logistical constraints, economies of scale, economic efficiency gains and local content efforts.

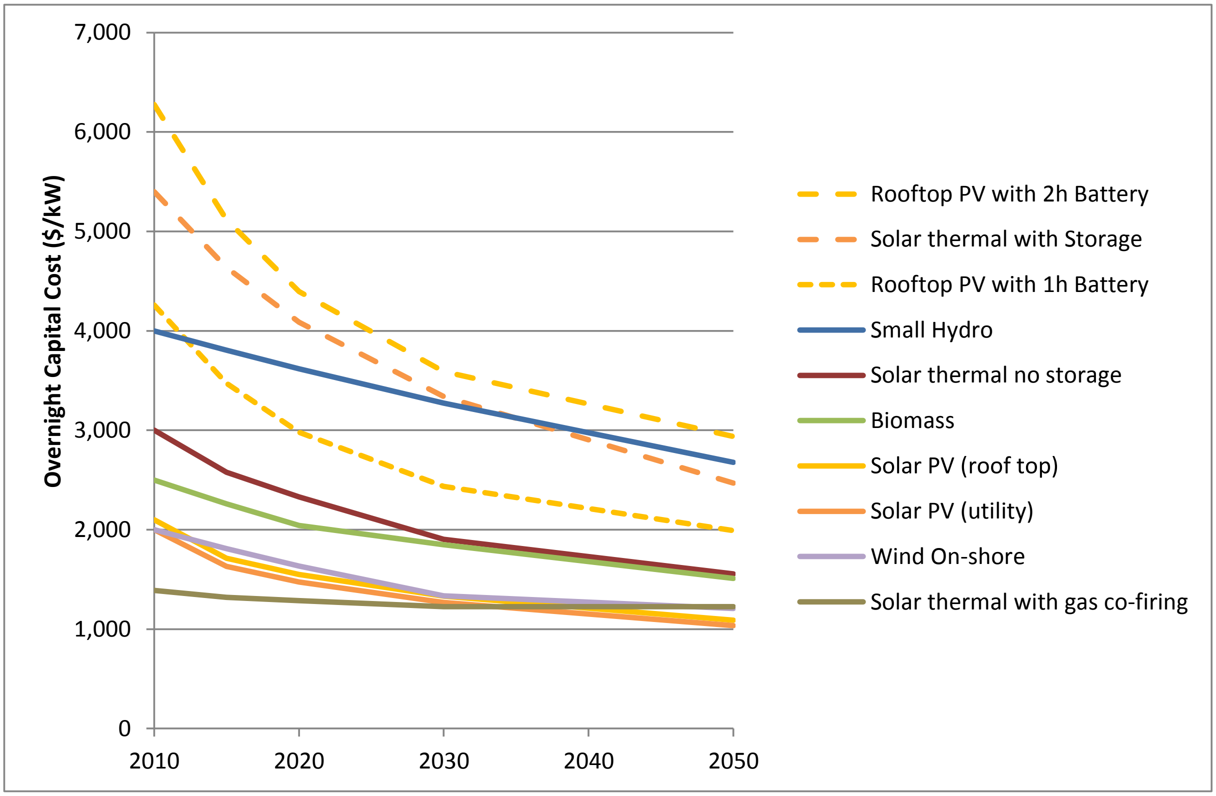

Figure 4 Overnight Investment cost for RE technologies (in RE scenario)

Other parameters are given in Table 7. They are kept identical in all scenarios. The construction duration affects the Interest During Construction (IDC) which MESSAGE calculates and incorporates into the optimization procedure.

Table 7: Other Parameters for RE Technologies

	Load Factor	O&M	Efficiency	Const. Duration	Life
	%	$/MWh	%	Years	Years
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 (roof top)	20%	23.8		1	20
PV with Battery 1hr storage	22.5%	19.0		1	20
PV with Battery 2hr storage	25%	17.1		1	20
Solar CSP no storage	35%	22.3		4	25
Solar CSP with Storage	63%	18.9		4	25
Solar CSP with gas co-firing	85%	18.9	53%	4	25

Generic Non-RE Power Generation Technologies

Table 8 shows the assumptions used for non-RE power generation technologies. They are mainly based on the WAPP Master Plan report, except for the distributed diesel generators where parameters are sourced from the ESMAP 2007 study on distributed generators

Table 8 Assumptions on Non-RE Power Generation Technologies

	Overnight Costs 2010	Constr. Duration	Availability	O&M	Efficiency
	$/kW	Years	%	$/MWh	%
Diesel/Gasoline 1kW system (urban/rural)	692	0	30%	33.2	16%
Diesel 100kW system (industry)	659	0	80%	55.4	35%
Diesel Centralized	1,070	2	80%	17.0	35%
HFO	1,350	2	80%	15.0	35%
OCGT	603	2	85%	19.9	30%
CCGT	1,069	3	85%	2.9	48%
Supercritical coal	2,403	4	85%	14.3	37%

Levelized costs of generic technologies

Based on the above assumptions on investment costs, operation and maintenance costs, fuel prices, and theoretical life time and capacity factor, a levelized cost of electricity (LCOE) was computed for generic technology options available to the countries in the region. In the case of renewable energy technologies, LCOE was computed using investment cost assumptions for the reference scenario and for the Renewable scenario. LCOE of T&D costs are added in the case technologies requires grid connection. LCOE of T&D costs are computed differently for different demand categories due to the differently assumed losses and differently assumed T&D infrastructure requirement. The analysis was conducted on the two scenarios of evolution of the investment cost for Renewable Energy technologies as described above: Reference and Renewable. The computed LCOE are shown in Table 9 for 2010, in Table 10 for 2020 and in Table 11 for 2030.

The levelized cost table shows that for industrial customers connecting at high voltage, hydro is the cheapest option followed by combined cycle gas with domestic gas. For countries that have domestic coal, coal generation is the next cheapest. CCGT with imported gas is initially the next cheapest option, but is overtaken by high capacity factor wind as its investment cost comes down and the gas price goes up in 2020. Electricity from imported coal is the next option, but this also changes by 2020 and 2030, with again wind becoming more cost effective. Biomass, where it is available is the next cheapest. Initially, gas co-fired solar CSP is interesting but this option gets overtaken by PV and solar thermal without storage, as the price is expected to go up. PV utility and solar CSP are the next options for countries without any other domestic resources of gas, coal, wind or biomass.

For rural customers, mini hydro remains the best option, where it is available. Distributed/roof-top PV with and without battery is expected to become the next best option for these customers in the Renewable scenario.

Note that the LCOE results shown here assume a load factor equal to the availability of the technologies. Given differences in investment cost and fuel cost, the ranking would change at different load factors. For example gas plants at 80% load factor may be less competitive than coal on a levelized basis, but more competitive at 40%. Diesel or OCGT's would be competitive at very low load factors, and may well play a role to meeting peak loads, which occur for short durations. The MESSAGE model takes account of this in the optimization, which is one of the reasons why the results of the optimization may differ from what could be expected given the simple LCOE analysis carried out here.

Table 9 LCOE Comparisons in 2010

	Grid?	Grid	Ind	Urban	Rural	Grid	Ind	Urban	Rural
		LCOE $/MWh				Ranking (Cheapest to Most Expensive)			
Diesel Centralized	1	291	328	393	464	19	16	18	19
Dist. Diesel 100kW	0	320	320			20	15		
Dist. Diesel/Gasoline 1kW	0	604		604	604	21		19	20
HFO	1	188	217	272	335	17	14	17	18
OCGT (Imported Gas/LNG)	1	141	167	216	276	11	10	12	14
CCGT (Imported Gas/LNG)	1	90	112	156	212	3	3	4	6
CCGT (Domestic Gas)	1	90	112	156	212	3	3	4	6
Supercritical coal	1	101	124	169	226	5	5	7	8
Supercritical Domestic Coal	1	81	102	145	201	2	1	2	5
Hydro	1	62			178	1			4
Small Hydro	0	102	102	102	102	6	2	1	1
Biomass	1	104	127	173	231	8	7	9	10
Bulk Wind (20% CF)	1	149	176	226	287	13	12	14	16
Bulk Wind (30% CF)	1	102	125	170	228	7	6	8	9
Solar PV (utility)	1	121	145	192	251	10	9	11	13
Solar PV (roof top)	0	152		152	152	14		3	2
PV with Battery (1h storage)	0	250		250	250	18		15	12
PV with Battery (2h storage)	0	163		163	163	15		6	3
Solar CSP no storage	1	147	173	223	284	12	11	13	15
Solar CSP with Storage	1	177	205	258	321	16	13	16	17
Solar CSP with gas co-firing	1	106	129	175	233	9	8	10	11

Table 10 LCOE Comparisons in 2020

	Grid?	Ref. Grid	RE Grid	RE Ind	RE Urban	RE Rural	Ref. Grid	RE Grid	RE Ind	RE Urban	RE Rural
	LCOE $/MWh						Ranking (Cheapest to Most Expensive)				
Diesel	1	325	325	364	432	506	19	19	16	18	19
Dist. Diesel 100kW	0	355	355	355			20	20	15		
Dist. Diesel/Gasoline 1kW	0	693	693		693	693	21	21		19	20
HFO	1	208	208	238	295	360	17	18	14	17	18
OCGT (Imported Gas/LNG)	1	154	154	180	231	292	14	16	13	16	17
CCGT (Imported Gas/LNG)	1	98	98	120	165	222	3	7	6	8	10
CCGT (Domestic Gas)	1	98	98	120	165	222	3	7	6	8	10
Supercritical coal	1	104	104	127	173	231	7	9	8	10	12
Supercritical Domestic Coal	1	89	89	110	154	211	2	3	3	5	7
Hydro	1	62	62			178	1	1			4
Small Hydro	0	102	93	93	93	93	5	5	1	1	1
Biomass	1	104	92	114	158	215	8	4	4	6	8
Bulk Wind (20% CF)	1	149	125	150	197	257	12	13	11	14	15
Bulk Wind (30% CF)	1	102	86	108	151	208	6	2	2	4	6
Solar PV (utility)	1	121	94	116	161	218	10	6	5	7	9
Solar PV (roof top)	0	152	118		118	118	13	11		2	2
PV with Battery	0	250	181		181	181	18	17		11	5
Solar CSP no storage	1	163	131		131	131	15	14		3	3
Solar CSP with Storage	1	147	119	143	190	249	11	12	10	13	14
Solar CSP with gas co-firing	1	177	138	164	213	273	16	15	12	15	16

Table 11 LCOE Comparisons in 2030

	Grid?	Ref. Grid	RE Grid	RE Ind	RE Urban	RE Rural	Ref. Grid	RE Grid	RE Ind	RE Urban	RE Rural
		LCOE $/MWh					Ranking (Cheapest to Most Expensive)				
Diesel	1	339	339	380	449	524	19	19	16	18	19
Dist. Diesel 100kW	0	371	371	371			20	20	15		
Dist. Diesel/Gasoline 1kW	0	740	740		740	740	21	21		19	20
HFO	1	216	216	248	305	371	17	18	14	17	18
OCGT (Imported Gas/LNG)	1	161	161	188	240	302	14	17	13	16	17
CCGT (Imported Gas/LNG)	1	102	102	125	170	228	4	8	7	10	11
CCGT (Domestic Gas)	1	102	102	125	170	228	4	8	7	10	11
Supercritical coal	1	106	106	129	174	232	8	12	10	13	14
Supercritical Domestic Coal	1	93	93	115	159	216	2	6	5	8	9
Hydro	1	62	62			178	1	1			5
Small Hydro	0	102	85	85	85	85	3	4	1	1	1
Biomass	1	104	86	108	151	208	7	5	4	7	8
Bulk Wind (20% CF)	1	149	106	129	174	232	12	11	9	12	13
Bulk Wind (30% CF)	1	102	73	94	136	191	6	2	2	4	6
Solar PV (utility)	1	121	84	105	149	205	10	3	3	5	7
Solar PV (roof top)	0	152	105		105	105	13	10		2	2
PV with Battery	0	250	151		151	151	18	16		6	4
Solar CSP no storage	1	163	110		110	110	15	13		3	3
Solar CSP with Storage	1	147	102	124	170	227	11	7	6	9	10
Solar CSP with gas co-firing	1	177	116	140	187	245	16	15	12	15	16

4.7 Assumptions on Trade between Countries

Trade between countries is limited by existing infrastructure, and planned transmission projects. Existing transmission infrastructure and planned projects for transmission are based on (WAPP 2011) and are summarized in Table 12 and in Table 13, with details in Table 19 and Table 20 in the appendices. In the case of "import restriction scenario", 25% of import in the total electricity demand is set to be a limit.

Table 12 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	327
Nigeria	Togo/Benin	686
Nigeria	Niger	169
Ghana	Cote d'Ivoire	327

Table 13 New Cross-Border Transmission Projects

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

4.8 Constraints related to system and unit operation

Reserve margin

A reserve margin constraint of 10% has been imposed on countries. 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 share of capacity that is accounted as 'Firm'
- $C_{EP}(i)$ is the capacity of power plant/technology *(i)* (centralized only)
- *D* is the peak demand on the centralized grid system
- *RM* is the reserve margin (e.g. 10%)

Constraints on Intermittent Renewables

Given that the model has a very aggregate representation of the load, the intermittency of wind and solar PV was accounted for in an aggregate but 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 30MW at any given point in time). The firm capacity of every MW of installed capacity was set to half the availability factor (capacity credit = half availability, in this example, 15MW).
- Centralized PV plants were given a 5% capacity credit.
- An upper limit on the share of grid electricity coming from wind was set for all countries at 20% and 10% for centralized PV.

Ramp rates

There are some technical limitations as to how fast coal plants can ramp up or down production. To try and capture this limitation, all coal plants in the model were de-rated by (1-availability). For example, a 100 MW coal plant with an availability of 85% can only produce up to 85MW at any given point in time. MESSAGE has a built-in function for ramp rate, and this constraint may be implemented in the next version of the model.

5 Least-Cost Optimization Results

5.1 Reference scenario

The reference scenario is set up in a way that is consistent with the reference scenario of the WAPP Master plan. In this scenario, the decided and planned regional transmission projects are included to allow the regional trade, fossil fuel prices are set constant over the planning horizon, and renewable energy technology investment costs decrease following the historical trends. As done in the WAPP Master Plan, the decided projects are commissioned at fixed date while the candidate projects are regarded as investment options from 2014 on for the thermal projects and from 2018 for the hydropower projects. The main differences are:

1. the demand projections include the additional mining demand, which is about 8% higher than the demand used in the reference scenario of the WAPP Master Plan for 2025, and
2. decentralized electricity supply options to meet the residential/commercial/small industry demand are explicitly modelled.

As expected, the results are consistent with those presented in the Master Plan reference scenario. Figure 5 presents the electricity generation mix in the reference scenario.

The main difference between the EREP results and the WAPP Master Plan is the lower share of hydro in the EREP model due to the 'dry-year' assumption imposed over the entire modeling horizon.

It is worth noting that ERE filled current supply-demand gap with on-site diesel generators. As more power supply option becomes available, this gap is filled quickly and replaced by grid-supply electricity or on-site renewable energy technology options, mainly mini-hydro option.

Hydropower share in the total electricity generation increases from 18% to 34% (22% and 29% of grid-connected electricity, respectively), and the share of other renewables remains small, 5% by 2030 with most of it being biomass.

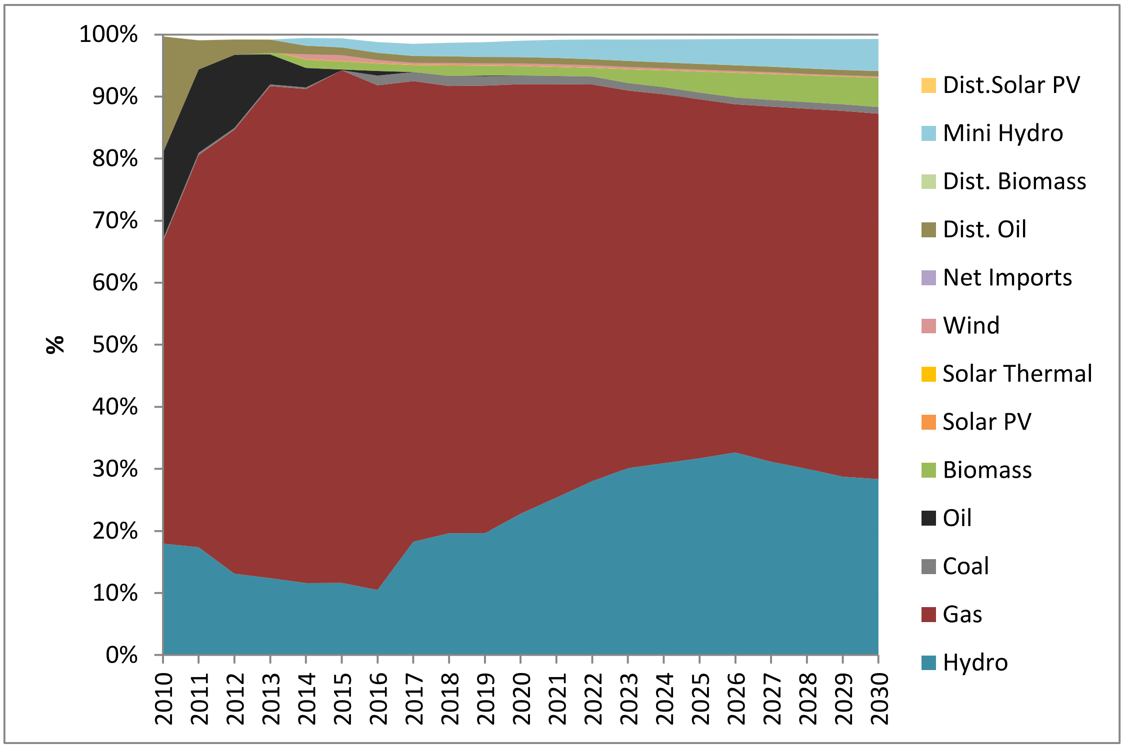

Figure 5: Electricity production in the reference scenario

5.2 Renewable Scenario

In the renewable scenario, we explore how much renewable energy technologies enter into the least-cost solution under favorable conditions. These conditions include investment reduction of renewable energy technologies, escalation of fossil fuel prices, and import from Central Africa providing access to its rich hydro resources.

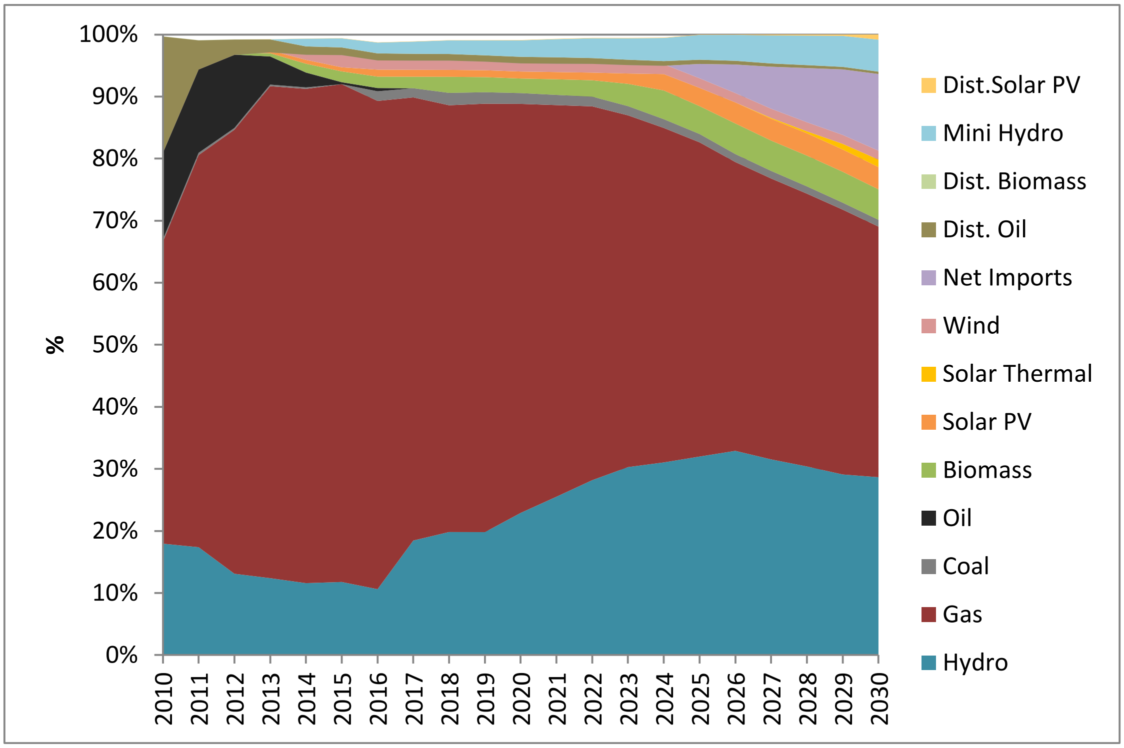

Figure 6: Electricity supply (regional generation plus import from the Central Africa) in the renewable scenario

Looking at the electricity supply mix in the renewable scenario[3] (Figure 6) in 2030, the share of the hydro power (including both big hydro projects and mini-hydro) remains almost the same as the reference case (34%), other renewable accounts 15%, the fossil based electricity production 39%, and the remaining supply of 12% is provided by import from the Central Africa.

Decentralized electricity supply options, virtually all based on renewable sources, account for 6.5% of total electricity supply.

The above overall picture is somehow dominated by the development in Nigeria and in Ghana, as they account for about 60% and 10% of the total regional electricity demand. Figure 7 shows the breakdown of the power supply mix by country in 2030 in the reference scenario and the renewable scenario.

[3] Note that these shares are based on the electricity supply, i.e., domestic electricity generation plus import from the Central Africa ,but not based on the domestic electricity generation. If we evaluate the share based on the domestic electricity generation, the shares will become 39% for the hydro, other renewables 15%, and the remaining 46% fossil.

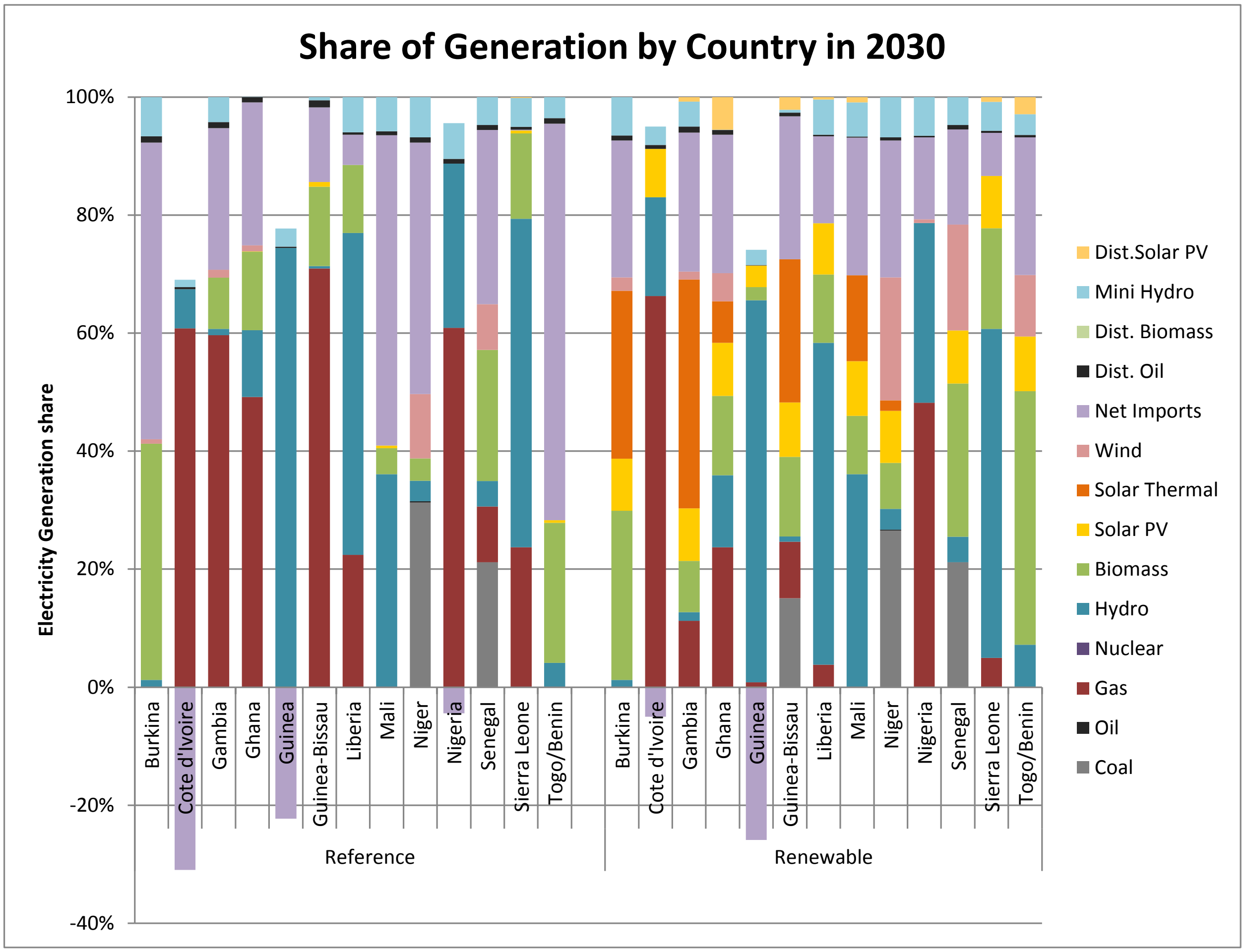

Figure 7 Share of Generation by Technology by Country in 2030: Reference vs Renewable Scenario

The penetration of renewable in the region in the renewable scenario is 49%, but on country by country basis, much higher penetration is economically favorable in some countries under the renewable scenario. In Burkina Faso, Guinea and Mali, the renewable energy penetration becomes virtually 100%. Hydro plays a major role in Cote d'Ivoire, Guinea Bissau, Liberia, Nigeria and Sierra Leone.

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 bases, these technologies become important part of electricity generation portfolio in some countries. For example, these three technologies together, account for more than 90% of the domestically produced grid connected electricity is accounted in Burkina Faso, and Gambia[4]. More than 40% is accounted in Ghana, Guinea-Bissau, and Senegal.

[4] However the share of domestic generation in the total domestic system demand is relatively small (19% and 30% for Burkina and Gambia) as the results include high share of import.

Countries that rely on imported gas in the reference scenario do not use gas any more in the least-cost solution under the renewable scenario. Share of coal use is also significantly reduced, and the demand is met by renewable based power instead.

Figure 8 shows the total electricity generation from renewable energy technologies for each country in the region for the Renewable scenario. Nigeria, shown on the secondary axis dominates in proportion to the size of the demand. Of the other countries, Guinea and Ghana have the largest production from renewables.

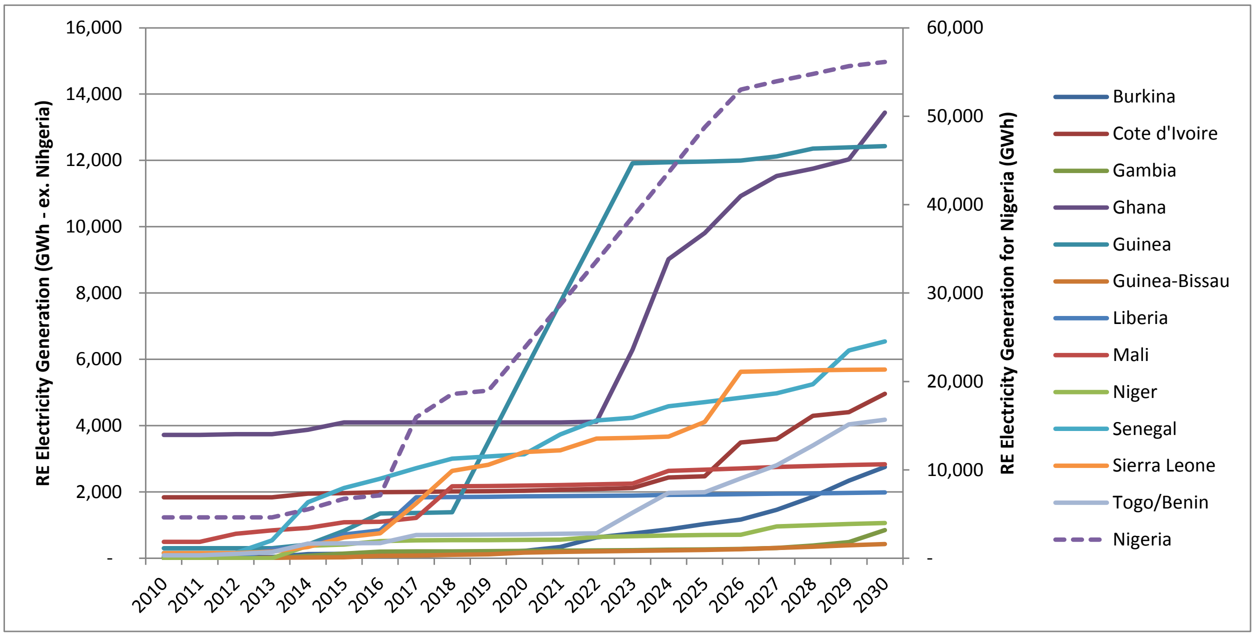

Figure 8 Total RE Electricity Generation by Country

Figure 9 shows the regional energy trade flows in 2030.

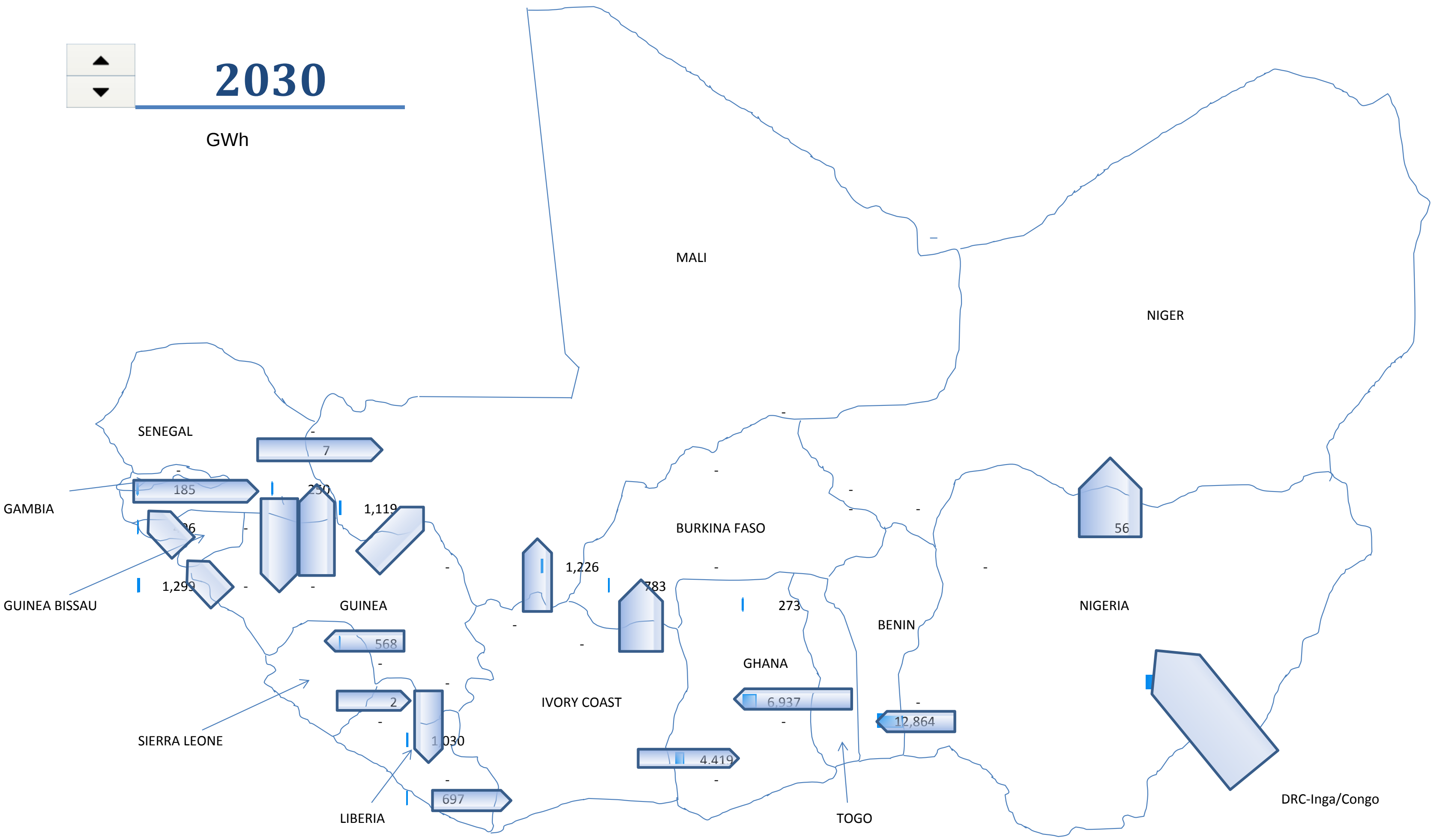

Figure 9: regional trade in 2030 in the renewable scenario

Figure 10 shows the share of Urban and Rural Electricity Demand met by distributed generation in 2030 for the Renewable Scenario. In Urban sectors most of this distributed generation is in the form of roof-top PV with battery with some diesel generation, and in Rural Sectors, most of the distributed is in the form of mini hydro, in countries where it is available, the difference being met with a mix of diesel generators and roof-top PV with battery.

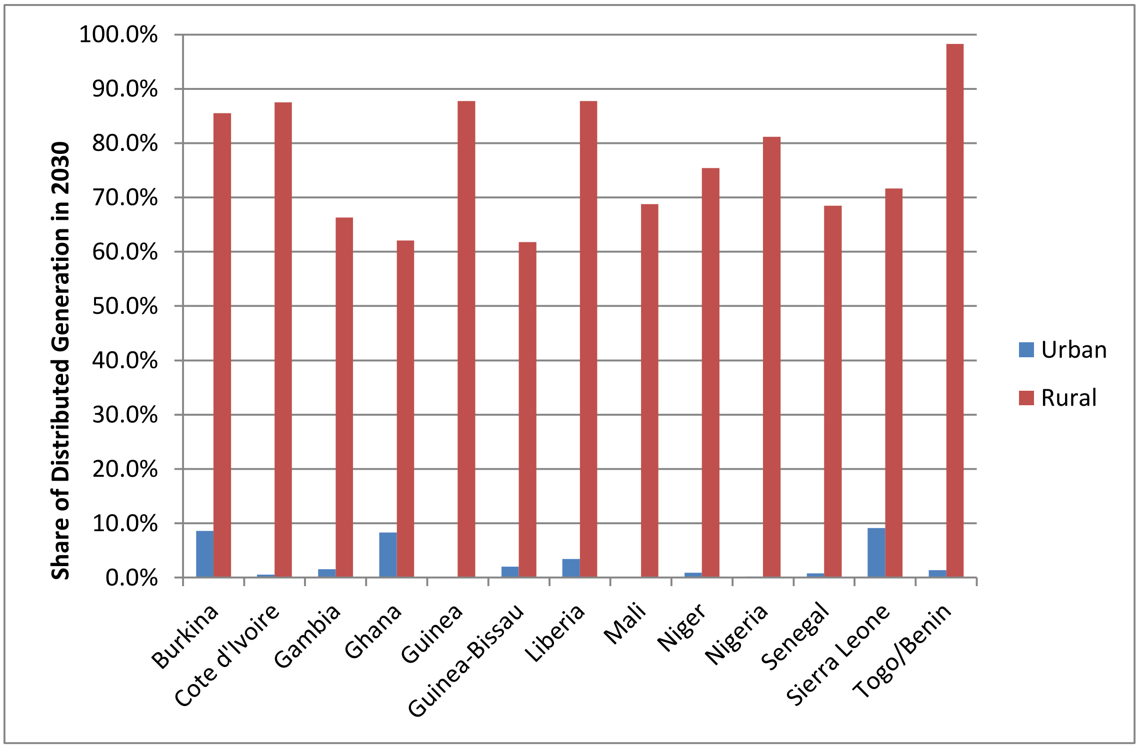

Figure 10 Share of Urban and Rural Electricity Demand met by Distributed Generation in 2025 for RE Scenario

Figure 11 shows the new capacity installation by technology and by year. The higher demand resulting from the inclusion of mining projects means that in many countries the projects in planning are not sufficient. Renewable projects with short lead-times such as wind, biomass, mini hydro and PV play a role (in 2014) until other larger scale projects (e.g. hydro) get commissioned. While fossil power plant additions dominate 2010-2020, the majority of power plant additions after 2020-2030 are based on renewables, and this is of course more prominent in the Renewable Scenario where significant investment in wind is made once all the hydro potential has been developed.

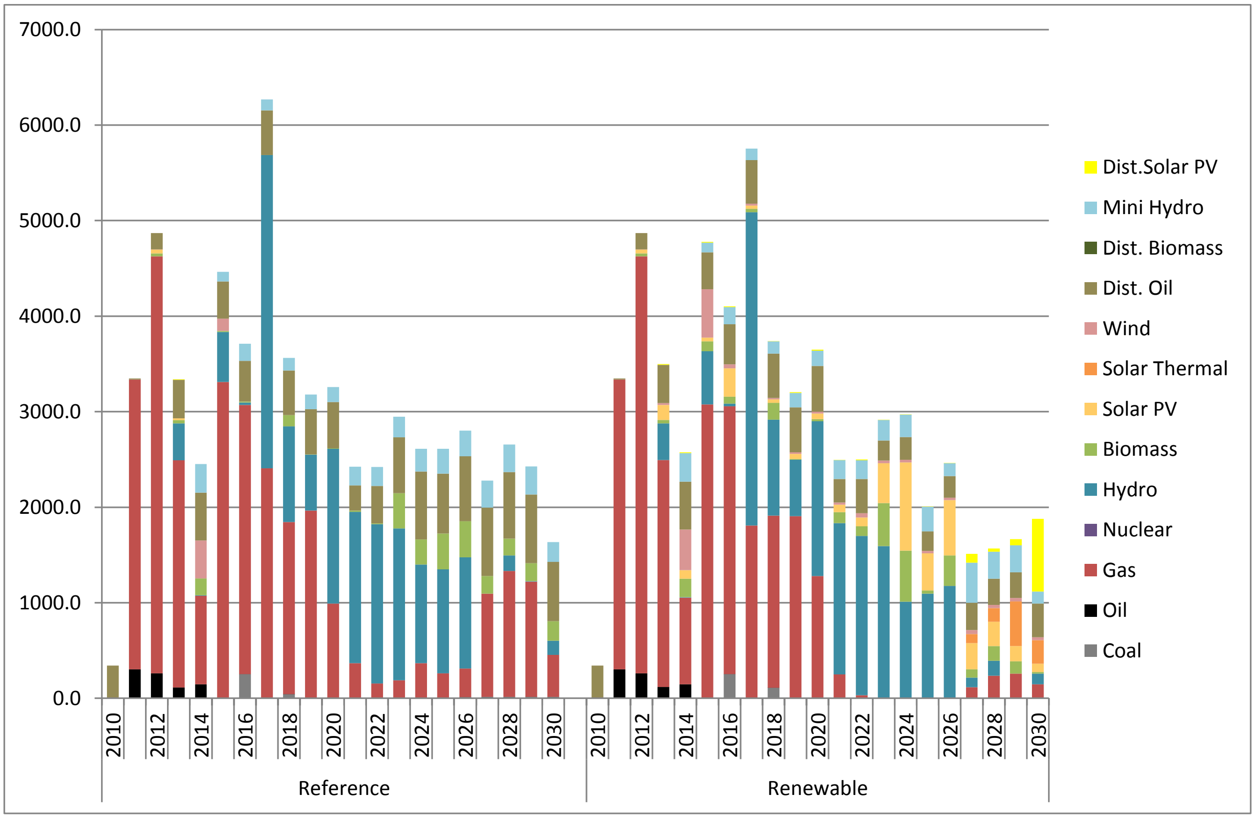

Figure 11 New Capacity Summed over the region

Table 14 shows the capacity addition during 2010-2030 by countries, presented for centralized power generation capacity and decentralized power generation capacity by country for the Reference and the Renewable scenarios.

Table 14: Capacity addition during 2010-2030 period by country in MW

	Centralized Total and renewable		Decentralized Total and renewable	
Burkina	844	732	257	121
Cote d'Ivoire	3,384	963	639	152
Gambia	350	278	73	16
Ghana	5,182	2,928	2,192	896
Guinea	3,842	3,615	248	126
Guinea-Bissau	278	129	64	18
Liberia	560	402	79	47
Mali	890	682	163	72
Niger	646	469	114	47
Nigeria	29,031	10,504	6,334	2,674
Senegal	2,338	1,908	383	104
Sierra Leone	1,414	1,182	230	125
Togo/Benin	1,802	1,167	493	121
total	50,560	24,960	11,269	4,518

In the renewable scenario, import from Central Africa is included as an available option after 2025. Given the uncertainty of the Great Inga project, ran another scenario was tested without this option. Figure 12 shows the electricity production in the renewable scenario with and without import from Central Africa. When the import from the Central Africa is not allowed, it is substituted by the distributed solar PV system.

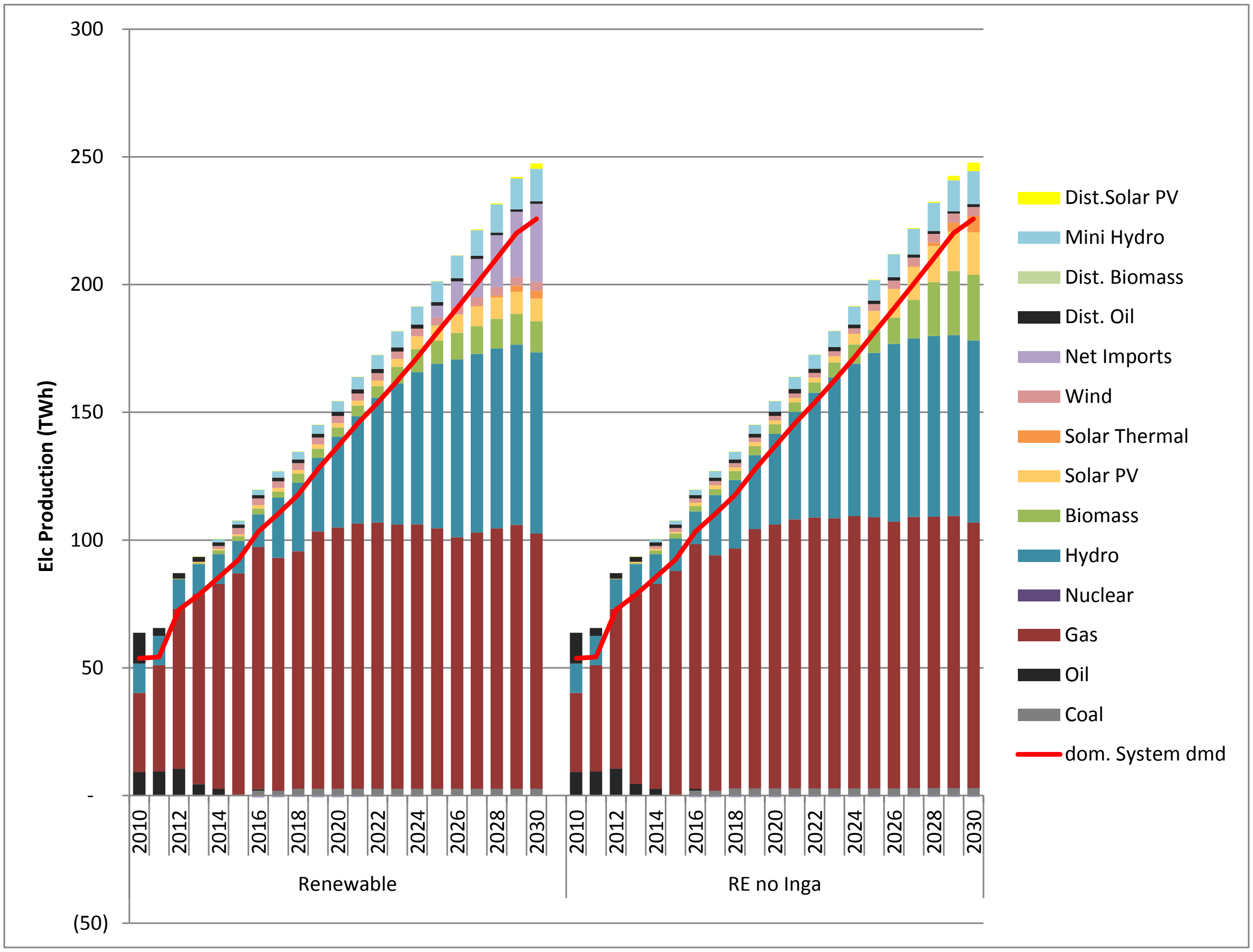

Figure 12: Electricity production in the renewable scenario with (left) and without (right) import from Central Africa

Country by country results shown in Figure 7 and the regional trade flow shown in Figure 9 indicate that some countries will rely heavily on import. There are some energy security concerns for relaying too much on imported electricity.

Figure 13 shows the electricity generation mix by country in the renewable scenario with a limited import share.

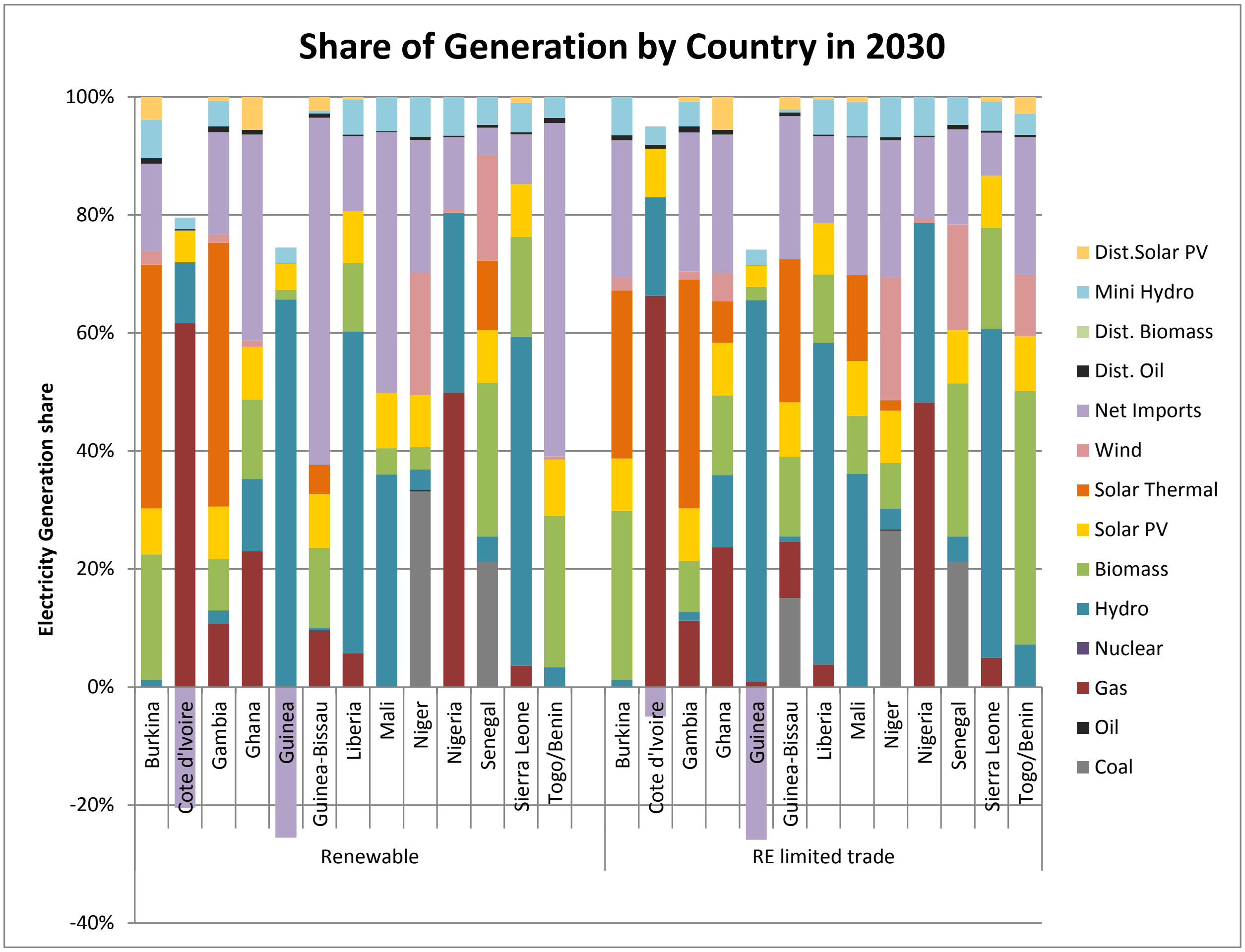

Figure 13: electricity generation mix by country in the renewable scenario vs renewable scenario with limited import share

Figure 14 shows the undiscounted system costs for selected years in the renewable scenario. Investment costs substantially grow to meet the growing electricity demand. Overall investment needs in the region between 2010 and 2030 amounts to 153 billion dollar (undiscounted) or 55 billion (discounted). This investment cost includes estimates of investment in domestic Transmission and Distribution costs and the cross-border transmission lines which add-up to about 35% of the total investment costs. The average cost of electricity drops from 19 US cents/KWh in 2010 to 12.5 US cents/KWh by 2030, explained mainly by reduction of reliance on expensive liquid fuels for power generation.

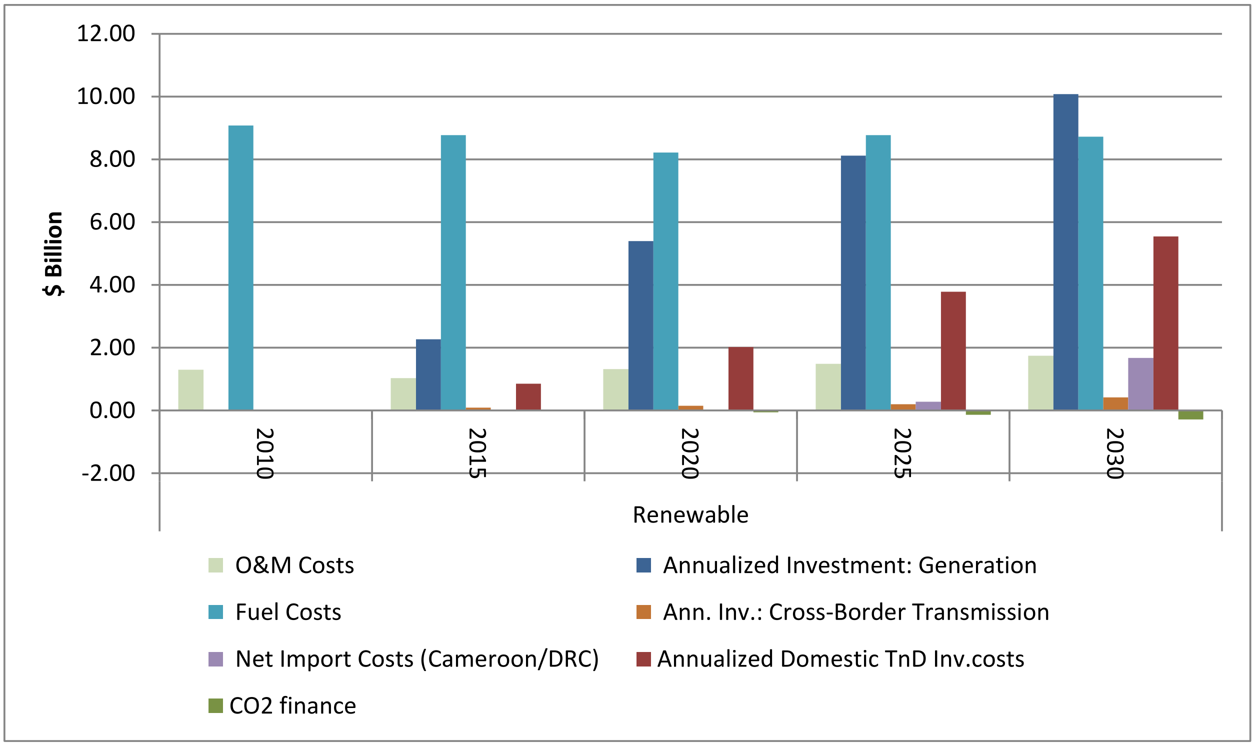

Figure 14: Annualized undiscounted costs in the renewable scenario

Average system costs are different in each country, reflecting mainly differences in existing infrastructure and available resources. In all countries we note a significant decrease in marginal costs over the study horizon, as the reliance on expensive to run diesel generators is reduced as investment in more cost effective options, in the form of hydro and gas, takes place.

6 Future work

The scenarios presented here could provide a starting point for further analysis. Energy planning is continuous process that requires revision as new information comes in. Further scenarios can be built for policy assessments. The EREP model is a medium and long term energy planning model for the region that optimizes supply to meet a given demand. Special attention has been focused on the representation of renewable power supply options and their integration into the power system. This framework is useful for techno-economic evaluation of power sector investment strategies in the WAPP, taking into account the existing and planned infrastructure, demand projections and existing and projected technology characterizations.

Any model output must be considered in the light of the input data, the model structure and the modelling framework limitations. The formalized modelling process allows for consideration of complex interactions and it allows for scenario and sensitivity analysis to account for future uncertainties. It is bad and misleading modelling practice to present a single model run as the 'optimal' future development. Furthermore, differences in the outputs between two scenarios with and without constraints can be interpreted as impacts of constraints

Limitations of the modelling undertaken include:

- The very roughly estimated breakdown of the demand into the three customer classes and the simple extrapolation of the projected electricity demand from 2030 to 2050 could be improved with more analysis of country data
- The representation of intra-country transmission lines may be overly simplistic. Some of the countries modelled are very large and have very limited existing transmission infrastructure that has to be expanded in order for some of the RE resource areas to be linked to areas of high demand, and also to allow for some of the cross-border connections to be possible. This could possibly be improved by further geographically disaggregating some of the larger countries and at the extreme, use approaches such as done in (Ummel 2010).
- The biomass and small hydro resource potential still needs better characterization.
- Applying dry-year assumptions over the entire modeling horizon under-plays the role of hydro and assuming average-year parameters for hydro over the horizon doesn't provide the system with adequate contingencies. This could be improved by increasing the level of sophistication of the model.
- The load curve in both cases was disaggregated into typical days for three different seasons. Each of those typical days were further disaggregated into "day", "night", "evening" and a "peak" to capture the variation in load and availability of some of the RE resources. With more detailed data this could be made more sophisticated at the expense of increased computational effort.
- The dispatch of power plants, given intermittency of renewables and the forced outage rate of thermal units was modeled in a simplistic manner given the already large optimization problem at hand. Reliability testing of the system using Monte Carlo on some of the modeling periods could be implemented to improve confidence in model.

- More dynamic response of demand from price pressures could possibly be included.

As a next step the IRENA secretariat through ECREEE will make the modeling framework available and provide capacity building for planners in the region. The model is populated with data in the public domain and from databases held by IRENA and its partner organizations. In a next round of analysis the data could be further improved in cooperation with ECOWAS members and training workshops are planned. Also the outcome of this activity will be shared with development partners.

To make the EREP model more accessible to analysts in the region, the model comes with data on all the existing power technologies and power projects in each country in a set of spreadsheets. The available domestic resources and the existing power system are characterized to reflect the system in each country. Existing trans-border transmission lines are also explicitly included. The decision makers can use analytical results from the EREP model to develop or to validate a national energy plan in the context of the power pool. The EREP model can also help to analyze the impacts of various policy interventions on the deployment of renewable and their benefit to the various aspects of sustainable development.

The evolutions of technical and economic characteristics of available technology options, availability of fossil and renewable resources, fuel prices, and various policy measures determine the extent to which renewable energy technologies can be deployed economically in the coming years. With EREP, one could further analyze:

1) how policy interventions may influence the level of economically competitive deployment of various renewable energy technologies to meet power demand from different segments,
2) the timing of new investment,
3) social, economic, and environmental consequences of policy interventions.

Where they can get the model (IAEA)

The main purpose was to provide decision makers and analysts from IRENA member countries in the region with an up-to-date planning tool to assess the future role and investment opportunities for renewable power generation. As a next step the IRENA secretariat through ECREEE will make the modeling framework available and provide capacity building for planners in the region. The model is populated with data in the public domain and from databases held by IRENA and its partner organizations. In a next round of analysis the data could be further improved in cooperation with ECOWAS members and training workshops are planned. Also the outcome of this activity will be shared with development partners.

7 Conclusions

The EREP model was developed to provide decision makers and analysts from IRENA member countries in the region with an up-to-date planning tool to assess the future role and investment opportunities for renewable power generation.

The model is populated with data in the public domain and from databases held by IRENA and its partner organizations. In a next round of analysis the data could be further improved in cooperation with the member states.

To summarize, key features of the EREP model include:

- The projected demand for electricity, data on the existing generation and trans-border transmission infrastructure, data on planned and proposed projects in the region for new generation as well as for trans-border transmission lines are all taken from the latest WAPP Master Plan for electricity production and transmission (WAPP 2011)
- The demand for electricity is split into three customer categories, namely: heavy industry, urban residential commercial and small industries, rural residential and commercial, to allow a better representation of decentralized power supply and improve the representation of the load curve
- Three customer categories are modeled to require different levels of transmission and distribution infrastructure and incur different levels of losses. They also have access to a different mix of distributed generation options
- The evolution of renewable energy technology costs and performance is taken from the latest study from IRENA
- Renewable energy potentials were taken from IRENA's new resource assessment studies
- Nuclear option was excluded from the analysis, as it requires further investigation into technical, legal, and economic challenges, and it is outside the scope of this study.

The results presented here should serve as a basis for further discussion. The methodology will be used a as framework for further refinement of general assumptions for a more detailed analysis of energy systems …

Two scenarios and two variations were developed using EREP as a basis for further analysis and possible elaboration. They are:

- A Reference scenario that was configured with consistent assumptions as used in the WAPP Master Plan: with international power trade, no cost reduction for the renewable energy technologies, with constant fossil fuel costs
- A Renewable scenario with international and inter-regional (i.e., from Central Africa) power trade, modestly escalating fossil fuel costs, cost reductions for renewable. Two variations were developed, one without import from Central Africa, the other with limitation on national electricity import share.
- Two variations of the Renewable Scenario were also developed:
  - No CA Imports: where imports from Central Africa (DRC/Cameroon) are excluded
  - Energy Security: where electricity imports are constrained to 25% by 2030.

A reference scenario was developed mainly to benchmark the model with the WAPP Master Plan. The focus of our analysis was on the renewable scenario and its variations.

The share of renewable power generation was 22% in 2010. In the Renewable scenario it rises to 56% in 2030 (of generation within the region). 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 in power generation varies from around 22% in Cote d'Ivoire to 100% in Burkina Faso, Guinea and Mali. Three quarters of this renewable power supply in 2030 is hydropower generation within the ECOWAS region, supplemented by imported hydropower from central Africa. Therefore hydropower should be a top priority in terms of renewable power development. In the Renewable scenario, renewables could have significant impact in the increasing access to electricity in rural areas.

The total capacity additions to meet the demand over the period of 2010-2030 is calculated as 68GW, of which one third is for the decentralized options. Forty-eight percent of the total capacity addition is accounted for by the renewable energy technologies in the renewable scenario. In the no CA Imports variation the share goes up to 56% and in the Energy Security Scenario the share stays at 55%. In all Renewable Scenario variations, decentralized options play an important role, especially in rural areas.

The investment needs over the period of 2010-2030 in the Renewable Scenario is 55 billion dollar (discounted).

As discussed in IRENA (IRENA 2011b), adequate electricity provision has been a challenge in 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 an enviable position to "choose their future" in energy. In the renewable scenario, we assumed relatively rapid reduction of renewable investment cost. Whether this is feasible or not depends on the level of policy and private sector engagement. The policy framework is imperative for a successful development of renewable energy.

For example, where possible the utility sector is liberalized and EPC contracts and IPPS become instruments to engage the private sector and enhance competition and technology transfer; indiscriminate fossil fuel and electricity price subsidies are replaced with discrete electricity quantities delivered through smart meters at low or zero price. All other electricity is delivered at a price that reflects production cost and the need to build up the necessary capital for future investments. Governments in the region engage with development partners to provide off-grid and mini-grid electricity supply solutions in rural areas. At the same time capacity building programs are started including vocational training for the youth, unemployed and women how to operate and maintain the equipment, how to develop project plans and projects and how to introduce new business models and learn from best practice elsewhere. All these efforts help to build a viable competitive market and overcome existing barriers. In this scenario, cross-border trade within the region and with Central Africa is encouraged, in order to more fully exploit the regional and neighboring hydro potential.

This report presents quantitative implication of “renewable scenario” in which all these opportunities are realized by the engagement of governments. It demonstrated valuable role that the renewable energy can play in meeting growing electricity demand in the region. It does so at a country level taking into account each of the countries particularities in terms of composition of demand and available resources, while taking into account regional considerations – identifying opportunities for trade benefiting both resource rich and resource poor countries.

8 References

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Appendix A: Detailed Demand Data

Table 15 Reference Electricity Demand Projections in GWh

	Senegal	Gambia	Guinée Bissau	Guinea	Sierra Leone	Liberia	Mali	Ivory Coast	Ghana	Togo/Benin	Burkina	Niger	Nigeria
2011	2,654	239	141	608	552	47	1,136	6,005	11,107	2,383	873	849	39,102
2012	2,654	239	141	608	552	47	1,136	6,005	11,107	2,383	873	849	39,102
2013	2,991	337	149	760	617	138	1,232	6,390	11,735	2,763	934	912	58,069
2014	3,147	414	157	934	994	294	1,382	6,799	13,064	3,004	1,006	977	61,321
2015	3,319	496	167	1,102	1,397	883	2,111	7,245	13,735	3,268	1,087	1,044	64,964
2016	3,744	586	176	1,563	1,498	1,446	2,226	7,731	14,455	3,547	1,173	1,235	68,830
2017	4,311	747	538	4,361	2,327	2,119	2,896	8,197	15,223	3,841	1,265	1,306	72,926
2018	4,536	771	584	4,448	3,102	2,136	2,997	8,680	16,041	4,151	1,362	1,379	77,258
2019	4,774	796	632	4,542	3,841	2,154	3,153	9,182	16,912	4,478	1,466	1,454	81,856
2020	5,026	821	683	6,739	5,003	2,174	3,248	9,703	17,840	4,822	1,576	1,530	86,717
2021	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
2022	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
2023	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
2024	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
2025	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
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
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
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

Figure 15 Load Shape Data - Ghana in 2012

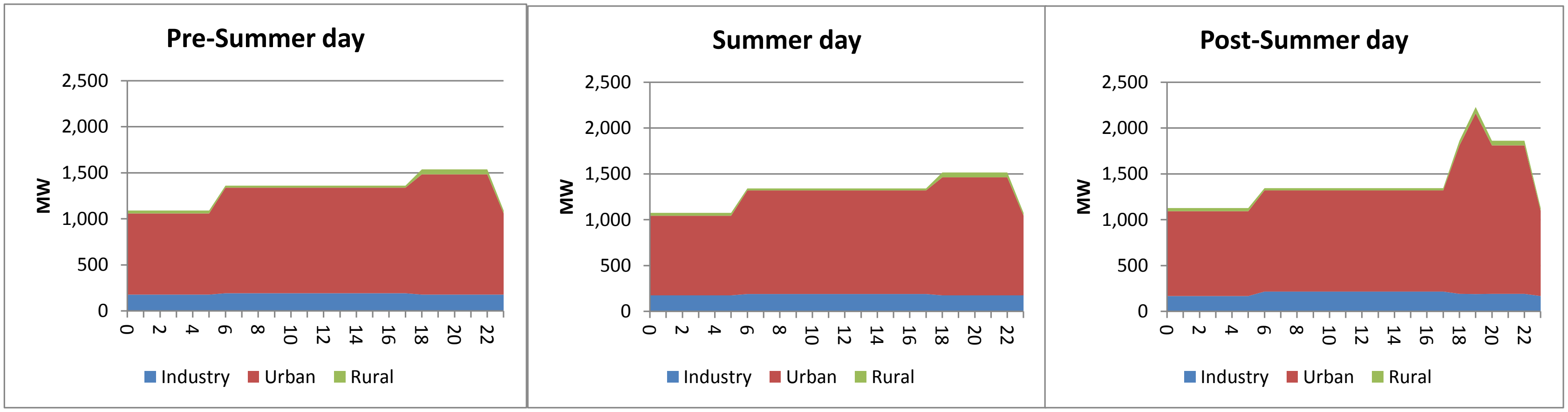
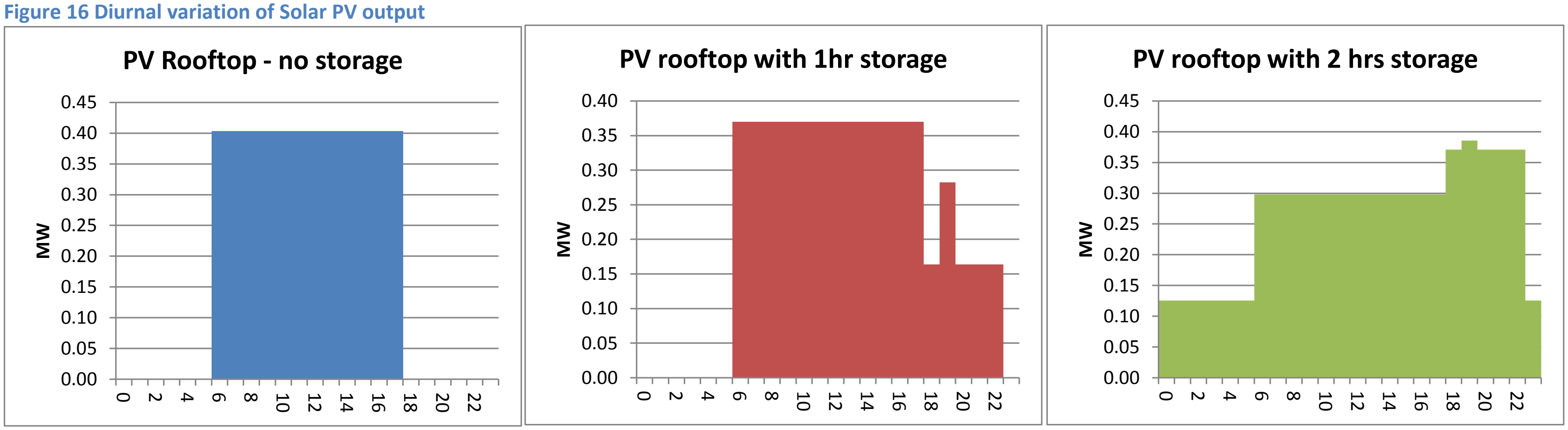


Figure 16 Diurnal variation of Solar PV output



Appendix B: Detailed Power Plant Assumptions

Table 16 Existing Thermal Power Stations

Name of Station	MESSAGE Name	Fuel	Plant Capacity MW	Available Capacity MW	Heat Rate GJ/MWh	Decom year	Forced Outage %	Planned outage h/yr	Variable O&M US$/MWh
Senegal				443.5					
Steam Turbine OHF	EPOHFEXST	OHF	87.5	53	12.90		8%	613	3.1
Diesel Generators OHF	EPOHFEXDI	OHF	280.5	275.5	9.00		10%	960	10
Gas Turbine ODS	EPODSEXGT	ODS	76	66	16.30		8%	613	2.5
Combined Cycle GAS	EPGASEXCC	GAS	52	49	9.20		8%	613	2
Gambia				49.2					
Diesel Generators ODS	EPODSEXDI	ODS	6	2.6	12.50		10%	960	10
Diesel Generators OHF	EPOHFEXDI	OHF	61	46.6	9.73		10%	960	10
Guinea-Bissau				3.672					
Diesel Generators ODS	EPODSEXDI	ODS	5.64	3.672	9.90		25%	960	10
Guinea				19					
Diesel Generators OHF	EPOHFEXDI	OHF	67.68	19	8.90	2012	10%	960	10
Sierra Leone				43.68					
Diesel Generators OHF	EPOHFEXDI	OHF	45.88	38.68	9.50		10%	960	10
Diesel Generators ODS	EPODSEXDI	ODS	5	5	10.40		10%	960	10
Liberia				12.64					
Diesel Generators ODS	EPODSEXDI	ODS	12.64	12.64	11.80		10%	960	10
Mali				134.35					
Diesel Generators ODS	EPODSEXDI	ODS	56.85	56.85	9.66		10%	960	10
Gas Turbine ODS	EPODSEXGT	ODS	24.6	20	15.60		8%	613	2.5
Diesel Generators OHF	EPOHFEXDI	OHF	57.5	57.5	9.40		10%	960	10
Cote d'Ivoire				765					
Gas Turbine GAS	EPGASEXGTAz	GAS	296	290	11.40	2013	5%	684	2.5

Name of Station	MESSAGE Name	Fuel	Plant Capacity	Available Capacity	Heat Rate	Decom year	Forced Outage	Planned outage	Variable O&M
Gas Turbine GAS	EPGASEXGTVr	GAS	95.6	84	14.40		3%	693	2.5
Gas Turbine GAS	EPGASEXGTC1	GAS	214.5	210	12.10		5%	638	2.5
Gas Turbine GAS	EPGASEXGTC3	GAS	111	111	12.10		5%	636	2.5
Gas Turbine GAS	EPGASEXGTAg	GAS	70	70	12.10	2013	5%	626	2.5
Ghana				865					
Combined Cycle OLC	EPOLCEXCC	OLC	330	300	8.70		22%	720	5
Gas Turbine OLC	EPOLCEXGT	OLC	346	300	12.53		13%	576	6.5
Gas Turbine ODS	EPODSEXGT	ODS	129.5	85	12.33		14%	576	4.5
Combined Cycle GAS	EPGASEXCC	GAS	200	180	8.20		7%	720	2
Togo/Benin				196.232					
Gas Turbine GAS	EPGASEXGT	GAS	156.332	139.732	13.30	2025	8%	613	2.5
Diesel Generators ODS	EPODSEXDI	ODS	99.3	51.5	10.65	2013	10%	960	10
Diesel Generators OHF	EPOHFEXDI	OHF	16	5	12.90	2015	10%	960	10
Burkina				146.49					
Diesel Generators ODS	EPODSEXDI	ODS	46.372	27.49	10.47		8%	1289	10
Diesel Generators OHF	EPOHFEXDI	OHF	132.918	119	9.63		9%	1095	10
Niger				66.6					
Steam Turbine COA	EPCOAEXST	COA	32	32	10.80		8%	613	3.1
Diesel Generators ODS	EPODSEXDI	ODS	15.4	4.6	10.40		10%	960	10
Diesel Generators OHF	EPOHFEXDI	OHF	12	10	9.50		10%	960	10
Gas Turbine GAS	EPGASEXGT	GAS	20	20	12.70		8%	613	2.5
Nigeria				3857.8					
Gas Turbine GAS	EPGASEXGT	GAS	4147.7	2558.7	12.70		8%	613	2.5
Steam Turbine GAS	EPGASEXST	GAS	2229.3	1299.1	10.57		8%	613	3.1

Table 17 Hydro Existing

Name of Station	MESSAGE Name	Hydro Type	Plant Capacity	Available Capacity	Installation year	Retirement Year	Forced Outage	Planned outage	Variable O&M	Average year	Dry year
			MW	MW			%	days/yr	$/MWh	GWh	GWh
Senegal	**SEN**			67.65						264	165
Manantali (OMVS) part Sénégal 33%	EPHYDEXMan	DAM	67.65	67.65	1988		5%	570	2	264	165
Guinea	**GUI**			94.9						481.8	379
Banéah	EPHYDEXDABan	DAM	5	1	1989	2015	5%	570	2	6.4	5
Donkéa	EPHYDEXRODon	ROR	15	11	1970	2015	5%	570	2	72.4	56
Grandes Chutes	EPHYDEXDAGra	DAM	27	3	1954	2015	5%	570	2	127	99
Garafiri	EPHYDEXDAGar	DAM	75	75	1999		5%	570	2	258	204
Kinkon	EPHYDEXDAKin	DAM	3.4	3.4	2006		5%	570	2	11.6	11
Tinkisso	EPHYDEXROTin	ROR	1.65	1.5	2005		5%	570	2	6.4	5
Sierra Leone	**SIE**			56						320.8	158
Goma 1	EPHYDEXROGom	ROR	6	6	2007		5%	570	2	30.8	1
Bumbuna 1	EPHYDEXDABum	DAM	50	50	2010		5%	570	2	290	157
Mali	**MAL**			153.18						683.3	495
Selingué	EPHYDEXDASel	DAM	46.2	43.48	1980		5%	570	2	224.7	198
Sotuba	EPHYDEXROSot	ROR	5.7	5.7	1966		5%	570	2	38.6	37
Manantali (OMVS) part Mali 52%	EPHYDEXDAMan	DAM	104	104	1988		5%	570	2	420	260
Cote d'Ivoire	**CIV**			584.8						2424	1842
Ayame 1	EPHYDEXDAAy1	DAM	19.2	19.2	1998		3%	632	2	60	46
Ayame 2	EPHYDEXDAAy2	DAM	30.4	30.4	1998		3%	1920	2	90	68
Buyo	EPHYDEXDABuy	DAM	164.7	164.7	1980		3%	752	2	900	684
Kossou	EPHYDEXDAKos	DAM	175.5	175.5	2004		3%	856	2	505	384
Taabo	EPHYDEXDATaa	DAM	210.6	190	2004		3%	872	2	850	646
Faye	EPHYDEXROFay	ROR	5	5	1984		3%	96	2	19	14

Name of Station	MESSAGE Name	Hydro Type	Plant Capacity	Available Capacity	Installation year	Retirement Year	Forced Outage	Planned outage	Variable O&M	Average year	Dry year
Ghana	**GHA**			1044						5051	3722
Akosombo	EPHYDEXDAAko	DAM	1020	900	2005		2%	359	0	4171	3100
Kpong	EPHYDEXROKpo	ROR	160	144	1982		2%	359	0.1	880	622
Togo/Benin	**TBN**			65						172.7	91
Nangbeto	EPHYDEXDANan	DAM	65.6	65	1987		5%	504	0	172.7	91
Burkina	**BUR**			23.238						91	41
Bagre	EPHYDEXDABag	DAM	14.4	11.52	1993	2018	5%	570	2	55.8	21
Kompienga	EPHYDEXDAKom	DAM	12.368	9.894	1988	2013	5%	570	2	30.9	16
Niofila	EPHYDEXRONio	ROR	1.68	1.344	1996	2021	5%	570	2	3.3	3
Tourni	EPHYDEXROTou	ROR	0.6	0.48	1996	2021	5%	570	2	1	1
Nigeria	**NGA**			1358.3						7476	4632
Shiroro	EPHYDEXDAShi	DAM	600	480.3	1989		5%	570	2	2628	1945
Jebba	EPHYDEXDAJeb	DAM	607.2	458	1986		5%	570	2	2373	1401
Kainji	EPHYDEXDAKai	DAM	781.2	420	1968		5%	570	2	2475	1286

Table 18 Considered and Committed Thermal Generation Projects

Project Name		Plant type	Fuel	MESSAGE Name	Available Capacity	Heat Rate	Start Year	Status	Forced Outage	Planned outage	Variable O&M	Fixed O&M	Investment Cost	Life
					MW	GJ/MWh			%	hrs/yr	$/MWh	$/kW	$/kW	
Senegal	**SEN**				1802.5									
Location	SENEPODSNCLoc	DI	ODS	EPODSNCLoc	150	10.4	2011	Décidée	10%	960	10	0	1124	30
new mobile	SENEPOHFNUnew	DI	OHF	EPOHFNUnew	150	9.5	2011	Planifiée	10%	960	10	0	1418	30
relocation	SENEPOHFNUrel	DI	OHF	EPOHFNUrel	120	9.5	2017	Envisagée	10%	960	10	0	1418	30
IPP Tou	SENEPOHFNUIPP	DI	OHF	EPOHFNUIPP	60	9.5	2017	Envisagée	10%	960	10	0	1418	30
belair	SENEPOHFNCbel	DI	OHF	EPOHFNCbel	30	9.5	2012	Décidée	10%	960	10	0	1418	30
unknown	SENEPOHFNUunk	DI	OHF	EPOHFNUunk	30	9.5	2017	Envisagée	10%	960	10	0	1418	30
Sendou	SENEPCOANCSen	ST	COA	EPCOANCSen	250	10.8	2016	Décidée	8%	613	3.1	0	971	35
Kayar	SENEPCOANUKay	ST	COA	EPCOANUKay	500	10.8	2017	Envisagée	8%	613	3.1	0	2489	35
St Louis	SENEPCOANUSt	ST	COA	EPCOANUSt	250	10.8	2017	Envisagée	8%	613	3.1	0	2489	35
ross betio	SENEPBIONCros	BIO	BIO	EPBIONCros	30	9.6	2014	Décidée	8%	613.2	0	130	3910	30
St Louis WP	SENEPWNDNUSt	WND	WND	EPWNDNUSt	125	0	2014	Envisagée	70%	0	10	17	1934	20
ziguinchor	SENEPSOLNUzig	SOL	SOL	EPSOLNUzig	7.5	0	2014	Envisagée	75%	0	0	20	5030	20
taiba ndiaye	SENEPWNDNUtai	WND	WND	EPWNDNUtai	100	0	2016	Envisagée	70%	0	10	17	1934	20
Gambia	**GAM**				16.5									
Brikama	GAMEPOHFNCBri	DI	OHF	EPOHFNCBri	15.5	9.5	2012	Décidée	10%	960	10	0	1417.5	30
Batokunku	GAMEPWNDNCBat	WND	WND	EPWNDNCBat	1	0	2012	Décidée	70%	0	10	17	1750	20
Guinea-Bissau	**GBI**				15									
Bissau	GBIEPOHFNCBis	DI	OHF	EPOHFNCBis	15	9.5	2012	Décidée	10%	960	10	0	1123.5	30
Guinea	**GUI**				226.8									
Tombo 3 (Rehab.)2012	GUIEPOHFNCT12	DI	OHF	EPOHFNCT12	66.24	9.2	2012	Décidée	10%	960	10	0	1123.5	30
Maneah	GUIEPOHFNCMan	DI	OHF	EPOHFNCMan	126	9.5	2014	Décidée	10%	960	10	0	1123.5	30

Project Name		Plant type	Fuel	MESSAGE Name	Available Capacity	Heat Rate	Start Year	Status	Forced Outage	Planned outage	Variable O&M	Fixed O&M	Investment Cost	Life
Sierra Leone	**SIE**				515									
Energeon	SIEEPBIONUEne	ST	BIO	EPBIONUEne	500	10.8	2018	Envisagée	8%	613	3.1	0	2489	35
Naanovo	SIEEPSOLNUNaa	SOL	SOL	EPSOLNUNaa	5	0	2018	Envisagée	75%	0	0	20	3660	20
Addax	SIEEPBIONUAdd	BIO	BIO	EPBIONUAdd	15	9.6	2018	Envisagée	8%	613.2	0	130	3604	30
Liberia	**LIB**				85									
Bushrod	LIBEPODSNCBus	DI	ODS	EPODSNCBus	10	11.8	2011	Décidée	10%	960	10	0	1124	30
Bushrod 2	LIBEPOHFNCBu2	DI	OHF	EPOHFNCBu2	40	9.5	2013	Décidée	10%	960	10	0	1124	30
Kakata (Buchanan)	LIBEPBIONUKak	BIO	BIO	EPBIONUKak	35	9.6	2013	Planifiée	8%	613.2	0	130	3604	30
Mali	**MAL**				365.38									
SIKASSO (CO)	MALEPODSNCSIK	DI	ODS	EPODSNCSIK	9.2	10.5	2011	Décidée	10%	960	10	0	1124	30
KOUTIALA (CI)	MALEPODSNCKOU	DI	ODS	EPODSNCKOU	4.4	10.8	2012	Décidée	10%	960	10	0	1124	30
KANGABA (CI)	MALEPODSNCKAN	DI	ODS	EPODSNCKAN	0.47	11.5	2014	Décidée	10%	960	10	0	1124	30
BOUGOUNI (CI)	MALEPODSNUBOU	DI	ODS	EPODSNUBOU	2.5	11	2015	Planifiée	10%	960	10	0	1124	30
OUELESSEBOUGOU (CI)	MALEPODSNUOUE	DI	ODS	EPODSNUOUE	0.44	11.7	2016	Planifiée	10%	960	10	0	1124	30
SAN (CI)	MALEPODSNUSAN	DI	ODS	EPODSNUSAN	3.7	10.4	2017	Planifiée	10%	960	10	0	1124	30
TOMINIAN (CI)	MALEPODSNUTOM	DI	ODS	EPODSNUTOM	0.36	11.6	2017	Planifiée	10%	960	10	0	1124	30
MOPTI (CI)	MALEPODSNUMOP	DI	ODS	EPODSNUMOP	8.4	10.6	2018	Planifiée	10%	960	10	0	1124	30
DJENNE (CI)	MALEPODSNUDJE	DI	ODS	EPODSNUDJE	0.91	12.4	2018	Planifiée	10%	960	10	0	1124	30
Balingue BID	MALEPOHFNCBal	DI	OHF	EPOHFNCBal	60	9.5	2011	Décidée	10%	960	10	0	1124	30
VICA BOOT	MALEPBIONUVIC	CC	BIO	EPBIONUVIC	30	8.8	2012	Planifiée	8%	613	2	0	957	25
Albatros BOOT	MALEPOHFNCAlb	DI	OHF	EPOHFNCAlb	92	9.5	2012	Décidée	10%	960	10	0	1124	30
Sosumar 1	MALEPBIONUSos	BIO	BIO	EPBIONUSos	3	9.6	2014	Planifiée	8%	613.2	0	130	3604	30
WAPP CC	MALEPODSNUWAP	CC	ODS	EPODSNUWAP	150	8.8	2019	Envisagée	8%	613	2	0	957	25
WAPP SOLAR	MALEPSOLNUWAP	SOL	SOL	EPSOLNUWAP	30	0	2019	Envisagée	75%	0	0	20	3660	20
Mopti SOLAR	MALEPSOLNCMop	SOL	SOL	EPSOLNCMop	10	0	2012	Décidée	75%	0	0	20	3660	20
Cote d'Ivoire	**CIV**				980									
Vridi (CIPREL)	CIVCIVEPGASNCc4	CC	GAS	CIVEPGASNCc4	222+111	8.8	2014	Décidée	8%	613	2	0	957	25
4e centrale IPP (Abbata)	CIVCIVEPGASNCAbb	CC	GAS	CIVEPGASNCAbb	450	8.8	2014	Planifiée	8%	613	2	0	957	25

Project Name		Plant type	Fuel	MESSAGE Name	Available Capacity	Heat Rate	Start Year	Status	Forced Outage	Planned outage	Variable O&M	Fixed O&M	Investment Cost	Life
Azito3	CIVCIVEPGASNCA3	CC	GAS	CIVEPGASNCA3	430	8.8	2013	Décidée	8%	613	2	0	957	25
G2	CIVCIVEPGASNCg2	CC	GAS	CIVEPGASNCg2	100	8.8	2013	Décidée	8%	613	2	0	957	25
Ghana	**GHA**				2144.5									
Effasu	GHAEPODSNUEff	GT	ODS	EPODSNUEff	100	11.2	2015	Planifiée	20%	576	4	0	633	25
Aboadze T3 phase 1	GHAEPOLCNCAbo	CC	OLC	EPOLCNCAbo	120	8.2	2012	Décidée	7%	672	2	0	957	25
Domini T1	GHAEPOLCNUDom	CC	OLC	EPOLCNUDom	300	11.6	2013	Planifiée	7%	504	2	0	957	25
Tema T1	GHAEPOLCNCTem	CC	OLC	EPOLCNCTem	210	11.6	2012	Décidée	7%	504	2	0	957	25
Aboadze T2	GHAEPOLCNCAb2	CC	OLC	EPOLCNCAb2	100	8.1	2014	Décidée	7%	672	2	0	957	25
Sunon Asogli phase 2	GHAEPGASNCSun	CC	GAS	EPGASNCSun	327.2	7.8	2013	Décidée	7%	672	2	0	957	25
Aboadze T3 phase 2	GHAEPOLCNUAb3	CC	OLC	EPOLCNUAb3	127.3	8.2	2016	Planifiée	7%	672	2	30	957	25
SolarPV	GHAEPSOLNCSol	SOL	SOL	EPSOLNCSol	10	0	2012	Décidée	75%	0	0	20	3660	20
Wind	GHAEPWNDNCWin	WND	WND	EPWNDNCWin	150	0	2014	Décidée	75%	0	0	20	1750	20
Aboadze T4 (WAPP)	GHAEPGASNCAb4	CC	GAS	EPGASNCAb4	400	7.3	2015	Décidée	7%	672	2	30	957	25
Togo/Benin	**TBN**				650									
CAI	TBNEPGASNCCAI	GT	GAS	EPGASNCCAI	80	12.7	2011	Décidée	8%	613	2.5	0	633	25
IPP_SOLAR	TBNEPSOLNUIPP	SOL	SOL	EPSOLNUIPP	20	0	2012	Planifiée	75%	0	0	20	3660	20
IPP_WIND	TBNEPWNDNUIPP	WND	WND	EPWNDNUIPP	20	0	2013	Planifiée	70%	0	10	17	1750	20
IPP_THERMAL	TBNEPGASNUIPP	GT	GAS	EPGASNUIPP	100	12.7	2013	Planifiée	8%	613	2.5	0	633	25
CEB_SOLAR	TBNEPSOLNUCEB	SOL	SOL	EPSOLNUCEB	10	0	2015	Planifiée	75%	0	0	20	3660	20
AFD_SOLAR	TBNEPSOLNUAFD	SOL	SOL	EPSOLNUAFD	5	0	2014	Planifiée	75%	0	0	20	3660	20
MariaGleta	TBNEPGASNCMar	CC	GAS	EPGASNCMar	450	8.8	2015	Décidée	8%	613	2	0	1984	25
Burkina	**BUR**				120.25									
Ouahigouya	BUREPODSNUOua	DI	ODS	EPODSNUOua	4.34	10.4	2012	Planifiée	10%	960	10	0	1124	30
Diebougou	BUREPODSNUDie	DI	ODS	EPODSNUDie	0.86	10.4	2011	Planifiée	10%	960	10	0	1124	30
Gaoua	BUREPODSNUGao	DI	ODS	EPODSNUGao	1.32	10.4	2011	Planifiée	10%	960	10	0	1124	30

Project Name		Plant type	Fuel	MESSAGE Name	Available Capacity	Heat Rate	Start Year	Status	Forced Outage	Planned outage	Variable O&M	Fixed O&M	Investment Cost	Life
Dori	BUREPODSNUDor	DI	ODS	EPODSNUDor	1.47	10.4	2011	Planifiée	10%	960	10	0	1124	30
Gorom-Gorom	BUREPODSNUGor	DI	ODS	EPODSNUGor	0.3	10.4	2011	Planifiée	10%	960	10	0	1124	30
Diapaga	BUREPODSNUDia	DI	ODS	EPODSNUDia	0.46	10.4	2013	Planifiée	10%	960	10	0	1124	30
Komsilga	BUREPOHFNCKom	DI	OHF	EPOHFNCKom	91.5	9.5	2011-2013	Décidée	10%	960	10	0	1124	30
Bobo 2	BUREPOHFNCBob	DI	OHF	EPOHFNCBob	20	9.5	2012	Décidée	10%	960	10	0	1124	30
Ouaga Solaire	BUREPSOLNUOua	SOL	SOL	EPSOLNUOua	20	0	2014	Planifiée	75%	0	0	20	3660	20
Mana (SEMAFO)	BUREPSOLNUMan	SOL	SOL	EPSOLNUMan	20	0	2012	Planifiée	75%	0	0	20	3660	20
Niger	**NIG**				249.6									
TAG Niamey 2	NIGEPGASNUTAG	GT	GAS	EPGASNUTAG	10	12.7	2011	Planifiée	8%	613	2.5	0	633	25
Niamey 2	NIGEPOHFNCNia	DI	OHF	EPOHFNCNia	15.4	9.5	2011	Décidée	10%	960	10	0	1124	30
Goudel	NIGEPOHFNUGou	DI	OHF	EPOHFNUGou	12	9.5	2012	Planifiée	10%	960	10	0	2058	30
Salkadamna	NIGEPCOANUSal	ST	COA	EPCOANUSal	200	10.8	2015	Envisagée	8%	613	3.1	0	8575	35
Zinder	NIGEPGASNCZin	CC	GAS	EPGASNCZin	8	8.8	2013	Décidée	8%	613	2	0	1749	25
Wind	NIGEPWNDNUWin	WND	WND	EPWNDNUWin	30	0	2014	Planifiée	70%	0	10	17	1578	20
Solar	NIGEPSOLNUSol	SOL	SOL	EPSOLNUSol	50	0	2014	Planifiée	75%	0	0	20	4322	20
Nigeria	**NGA**				13581.2									
2011	NGAEPGASNC011	GT	GAS	EPGASNC011	2953.2	12.7	2011	Décidée	8%	613	2.5	0	633	25
2012	NGAEPGASNC012	GT	GAS	EPGASNC012	4126	12.7	2012	Décidée	8%	613	2.5	0	633	25
2013	NGAEPGASNC013	GT	GAS	EPGASNC013	1452	12.7	2013	Décidée	8%	613	2.5	0	633	25
ICSPower	NGAEPGASNUICS	GT	GAS	EPGASNUICS	600	12.7	2015	Planifiée	8%	613	2.5	0	633	25
SupertekNig.	NGAEPGASNUSup	GT	GAS	EPGASNUSup	1000	12.7	2017	Planifiée	8%	613	2.5	0	633	25
Ethiope	NGAEPGASNUEth	GT	GAS	EPGASNUEth	2800	12.7	2017	Planifiée	8%	613	2.5	0	633	25
FarmElectric	NGAEPGASNUFar	GT	GAS	EPGASNUFar	150	12.7	2015	Planifiée	8%	613	2.5	0	633	25
Westcom	NGAEPGASNUWes	GT	GAS	EPGASNUWes	500	12.7	2015	Planifiée	8%	613	2.5	0	633	25

Table 19 Considered and Committed Hydro Projects

Name of Station	MESSAGE Name	Hydro Type	Available Capacity	Start Year	Status	Forced Outage	Planned outage	Variable O&M	Investment Cost	Average year	Dry year
			MW			%	days/yr	$/MWh	$/kW	GWh	GWh
Senegal	**SEN**		529.82						3187	1988	1100
Sambangalou(OMVG)partSénégal40%	EPHYDNUDASam	DAM	51.2	2017	Décidée	5%	570	2	3386	160.8	83.2
Kaleta(OMVG)partSénégal40%	EPHYDNUROKal	ROR	96	2016	Planifiée	5%	570	2	1114	378.4	90.8
Digan(OMVG)partSénégal40%	EPHYDNURODig	ROR	37.32	2018	Envisagée	5%	570	2	1201	97.0	9.5
FelloSounga(OMVG)partSénégal40%	EPHYDNUDAFel	DAM	32.8	2018	Envisagée	5%	570	2	3474	133.2	114.4
Saltinho(OMVG)partSénégal40%	EPHYDNUROSal	ROR	8	2018	Envisagée	5%	570	2	4273	32.8	9.5
Felou(OMVS)partSénégal15%	EPHYDNUROFel	ROR	15	2013	Décidée	5%	570	2	2400	87.5	80.0
Gouina(OMVS)partSénégal25%	EPHYDNUROGou	ROR	35	2017	Décidée	5%	570	2	2347	147.3	56.8
DAMEnvisagée	EPHYDNUDADAM	DAM	254.5	2019	Envisagée	5%	570	2	4311	950.8	656.1
Gambia	**GAM**		67.6						2100	241	92
Sambangalou(OMVG)partGambie12%	EPHYDNUDASam	DAM	15.4	2016	Planifiée	5%	570	2	3386	48.2	25.0
Kaleta(OMVG)partGambie12%	EPHYDNUROKal	ROR	28.8	2016	Planifiée	5%	570	2	1114	113.5	27.2
Digan(OMVG)partGambie12%	EPHYDNURODig	ROR	11.2	2018	Envisagée	5%	570	2	1201	29.1	2.8
FelloSounga(OMVG)partGambie12%	EPHYDNUDAFel	DAM	9.8	2018	Envisagée	5%	570	2	3474	40.0	34.3
Saltinho(OMVG)partGambie12%	EPHYDNUROSal	ROR	2.4	2018	Envisagée	5%	570	2	4273	9.8	2.8
Guinea-Bissau	**GBI**		13.6						2,109.15	48.13	18.44
Sambangalou(OMVG)partGuinéeBissau8%	EPHYDNUDASam	DAM	3.1	2016	Planifiée	5%	570	2	3386	9.7	5.0
Kaleta(OMVG)partGuinéeBissau8%	EPHYDNUROKal	ROR	5.8	2016	Planifiée	5%	570	2	1114	22.7	5.5
Digan(OMVG)partGuinéeBissau8%	EPHYDNURODig	ROR	2.2	2018	Envisagée	5%	570	2	1201	5.8	0.6
FelloSounga(OMVG)partGuinéeBissau8%	EPHYDNUDAFel	DAM	2	2018	Envisagée	5%	570	2	3474	8.0	6.9
Saltinho(OMVG)partGuinéeBissau8%	EPHYDNUROSal	ROR	0.5	2018	Envisagée	5%	570	2	4273	2.0	0.6
Guinea	**GUI**		3346.295						1482	14296	10974
Baneah(Rehab)	EPHYDNUDABan	DAM	5	2015	Décidée	5%	570	2	2400	6.4	4.9

Name of Station	MESSAGE Name	Hydro Type	Available Capacity	Start Year	Status	Forced Outage	Planned outage	Variable O&M	Investment Cost	Average year	Dry year
Donkéa(Réhab)	EPHYDNUDADon	DAM	15	2015	Décidée	5%	570	2	2400	72.4	55.5
GrandesChutes(Réhab)	EPHYDNUDAGra	DAM	27	2015	Décidée	5%	570	2	2400	127.0	99.2
Sambangalou(OMVG)partGuinée40%	EPHYDNUDASam	DAM	51.2	2016	Planifiée	5%	570	2	3386	160.8	83.2
Kaleta(OMVG)partGuinée40%	EPHYDNUDAKal	DAM	240	2015	Décidée	5%	570	2	1114	946.0	227.0
Digan(OMVG)partGuinée40%	EPHYDNUDADig	DAM	37.32	2018	Envisagée	5%	570	2	1201	97.0	9.5
FelloSounga(OMVG)partGuinée40%	EPHYDNUDAFel	DAM	32.8	2018	Envisagée	5%	570	2	3474	133.2	114.4
DAMEnvisagée	EPHYDNUDADAM	DAM	2929.975	2019	Envisagée	5%	570	2	2400	12720.3	10370.8
Saltinho(OMVG)partGuinée40%	EPHYDNUDASal	DAM	8	2018	Envisagée	5%	570	2	4273	32.8	9.5
Sierra Leone	**SIE**		754.7						2382	4168	3468
Goma2(Bo-Kenema)	EPHYDNUROGom	ROR	6	2015	Planifiée	5%	570	2	6709	30.8	1.4
Bumbuna2	EPHYDNUDABu2	DAM	40	2015	Planifiée	5%	570	2	1950	220.0	237.0
Bumbuna3(Yiben)	EPHYDNUDABu3	DAM	90	2017	Planifiée	5%	570	2	1950	396.0	317.0
Bumbuna4&5	EPHYDNUDABu4	DAM	95	2017	Planifiée	5%	570	2	1950	494.0	463.0
Benkongor1	EPHYDNUDABe1	DAM	34.8	2020	Planifiée	5%	570	2	2447	237.2	199.7
Benkongor2	EPHYDNUDABe2	DAM	80	2022	Planifiée	5%	570	2	2447	413.7	338.3
Benkongor3	EPHYDNUDABe3	DAM	85.5	2025	Planifiée	5%	570	2	2447	513.1	421.1
DAMEnvisagée	EPHYDNUDADAM	DAM	323.4	2026	Envisagée	5%	570	2	2561	1863.2	1490.5
Liberia	**LIB**		966.5						3306	4763	3633
MountCoffee(+Viareservoir)	EPHYDNUDAMou	DAM	66	2015	Décidée	5%	570	2	5803	435.0	344.0
SaintPaul -1B	EPHYDNUDASa1	DAM	78	2017	Envisagée	5%	570	2	3123	512.0	389.1
SaintPaul -2	EPHYDNUDASa2	DAM	120	2017	Envisagée	5%	570	2	3123	788.0	598.9
DAMEnvisagée	EPHYDNUDADAM	DAM	702.5	2019	Envisagée	5%	570	2	3123	3027.7	2301.1
Mali	**MAL**		410.935						3624	1854	1229
Sotuba2	EPHYDNUROSot	ROR	6	2014	Planifiée	5%	570	2	2400	39.0	37.4
Kenié	EPHYDNUROKen	ROR	11.47	2015	Planifiée	5%	570	2	3670.7	199.0	162.6

Name of Station	MESSAGE Name	Hydro Type	Available Capacity	Start Year	Status	Forced Outage	Planned outage	Variable O&M	Investment Cost	Average year	Dry year
Gouina(OMVS)partMali45%	EPHYDNUROGou	ROR	63	2017	Décidée	5%	570	2	2347	265.1	102.0
Felou(OMVS)partMali45%	EPHYDNUROFel	ROR	27	2013	Décidée	5%	570	2	2347	265.1	102.0
DAMEnvisagée	EPHYDNUDADAM	DAM	303.465	2018	Envisagée	5%	570	2	4025	1085.8	825.2
Cote d'Ivoire	**CIV**		1071.5						3255	4953	2916
Soubre	EPHYDNUDASou	DAM	270	2018	Planifiée	5%	570	2	2400	1116.0	0.0
AboissoComoé	EPHYDNUDAAbo	DAM	90	2026	Envisagée	5%	570	2	2756	392.0	297.9
GriboPopoli	EPHYDNUDAGri	DAM	112	2027	Envisagée	5%	570	2	3249	515.0	391.4
Boutoubré	EPHYDNUDABou	DAM	156	2028	Envisagée	5%	570	2	2570	785.0	596.6
Louga	EPHYDNUDALou	DAM	280	2029	Envisagée	5%	570	2	4751	1330.0	1010.8
Tiboto/Cavally(Intl.)partCI50%	EPHYDNUDATib	DAM	112.5	2030	Envisagée	5%	570	2	2570	600.0	456.0
Tiassalé	EPHYDNUROTia	ROR	51	2030	Envisagée	5%	570	2	4068	215.0	163.4
Ghana	**GHA**		661						3121	2330	1010
Bui	EPHYDNUDABui	DAM	342	2013	Décidée	1%	350	0	2400	1000.0	0.0
Juale	EPHYDNUDAJua	DAM	87	2014	Envisagée	1%	350	0.1	3552	405.0	307.8
Pwalugu	EPHYDNUDAPwa	DAM	48	2014	Envisagée	1%	350	0.1	3625	184.0	139.8
Hemang	EPHYDNUROHem	ROR	93	2014	Envisagée	1%	350	0.1	2688	340.0	258.4
Kulpawn	EPHYDNUDAKul	DAM	36	2014	Envisagée	1%	350	0.1	8111	166.0	126.2
Daboya	EPHYDNUDADab	DAM	43	2014	Envisagée	1%	350	0.1	4698	194.0	147.4
Noumbiel(Intl.)partGhana20%	EPHYDNUDANou	DAM	12	2014	Envisagée	1%	350	2	4767	40.6	30.9
Togo/Benin	**TBN**		357						2320	1004	722
Adjarala	EPHYDNUDAAdj	DAM	147	2017	Décidée	5%	570	2	2264	366.0	237.0
Ketou	EPHYDNUDAKet	DAM	160	2018	Envisagée	5%	570	2	2105	490.0	372.4
Tetetou	EPHYDNUDATet	DAM	50	2018	Envisagée	5%	570	2	3174	148.0	112.5
Burkina	**BUR**		60						5839	192	146
Noumbiel	EPHYDNUDANou	DAM	48	2021	Envisagée	5%	570	2	4767	162.4	123.4

Name of Station	MESSAGE Name	Hydro Type	Available Capacity	Start Year	Status	Forced Outage	Planned outage	Variable O&M	Investment Cost	Average year	Dry year
Bougouriba	EPHYDNUDABou	DAM	12	2021	Envisagée	5%	570	2	10125	30.0	22.8
Niger	**NIG**		278.5						3407	1269	486
Kandadji	EPHYDNUDAKan	DAM	130	2015	Décidée	5%	570	2	2400	629.0	0.0
Gambou	EPHYDNUDAGam	DAM	122.5	2016	Envisagée	5%	570	2	4712	528.0	401.3
Dyodyonga	EPHYDNUDADyo	DAM	26	2016	Envisagée	5%	570	2	2293	112.1	85.2
Nigeria	**NGA**		3300						1538	14223	10809
Mambilla	EPHYDNUDAMam	DAM	2600	2017	Envisagée	5%	570	2	1538	11205.8	8516.4
Zungeru	EPHYDNUDAZun	DAM	700	2018	Envisagée	5%	570	2	1538	3016.9	2292.9

Appendix C: Detailed Transmission Data

Table 20 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	1200	5.46%
Cote d'Ivoire	Burkina	225	327	221.8	3.48%
Nigeria	Togo/Benin	330	686	75	2.50%
Nigeria	Niger	132x2	169.2	162	2.62%

Table 21 Detailed Data for Transmission Projects

From	To	Stations	Voltage	Capacity per line	Distance	Losses	Total Investment	Investment cost	Earliest year
			kV	[MW]	km	%	US$million	$/kW	
Dorsale 330 kV (committed)									
Ghana	**Togo/Benin**	Volta - Sakete	330	655.2	240	2.5%	90.0	137.4	2013
Cote d'Ivoire	**Ghana**	Riviera - Presea	330	655.2	240	2%	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	1012.3	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**	Niamey (NI) - Ouagadougou (BU)	330	637.5	469	5.49%	250.4	392.8	2014
Hub Intrazonal									
Ghana	**Burkina**	Han (GH) - Bobo	225	332.2	210	2.50%	67.0	201.7	2014

From	To	Stations	Voltage	Capacity per line	Distance	Losses	Total Investment	Investment cost	Earliest year
		Dioulasse (BU)							
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

Appendix D: Detailed build Plan in RE Scenario

Transmission Projects

Dorsale

2013 Ghana to Togo/Benin 655MW
2017 Cote d'Ivoire to Ghana 655MW

CLSG

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

OMVG

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

Hub Intrazonal

2012 Mali to Cote d'Ivoire 320MW
2013 Ghana to Burkina 332MW
2015 Ghana to Burkina 332MW
2016 Guinea to Mali 123MW

Dorsale Mediane

2026 Nigeria to Togo/Benin 17MW
2030 Nigeria to Togo/Benin 396MW

Nigeria - Benin

2025 Nigeria to Togo/Benin 26MW
2026 Nigeria to Togo/Benin 303MW

Central Africa - Nigeria

2025 Central Africa to Nigeria 1000MW
2026 Central Africa to Nigeria 1000MW
2027 Central Africa to Nigeria 1000MW
2028 Central Africa to Nigeria 1000MW
2029 Central Africa to Nigeria 1000MW
2030 Central Africa to Nigeria 1000MW

Generation Projects by Country

Burkina

Centralized

2012 Bobo 2 20MW
2013 Komsilga 36MW
2014 Bulk Wind (30% CF) 29MW
2020 Biomass 12MW
2021 Biomass 25MW
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 Solar PV (utility) 7MW, Solar thermal no storage 82MW
2028 Solar PV (utility) 6MW, Solar thermal no storage 115MW
2029 Solar thermal no storage 150MW
2030 Solar thermal no storage 83MW

De-Centralized

2013 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 9MW
2014 Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 13MW
2015 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 4MW
2016 Diesel/Gasoline 1kW system (Rural) 1MW, 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) 4MW
2019 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 5MW
2020 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 11MW
2021 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 3MW
2022 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 11MW
2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 17MW
2025 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 8MW
2026 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW, 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 2MW, Diesel/Gasoline 1kW system (Urban) 8MW
2029 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 3MW
2030 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 12MW, Rooftop PV with 1h Battery 64MW

Cote d'Ivoire

Centralized

2012 Unserved 350MW
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 1000MW
2017 CCGT 108MW
2024 Solar PV (utility) 130MW
2026 Solar PV (utility) 450MW
2027 Solar PV (utility) 29MW
2028 Boutoubré 156MW, Solar PV (utility) 30MW
2029 Solar PV (utility) 31MW
2030 Tiboto/Cavally(Intl.)partCI50% 113MW, Solar PV (utility) 25MW

De-Centralized

2014 Small Hydro 25MW
2015 Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 51MW
2016 Small Hydro 11MW, Diesel/Gasoline 1kW system (Urban) 43MW
2017 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 43MW
2018 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 43MW
2019 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 43MW
2020 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 41MW
2021 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 12MW
2022 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 10MW
2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW
2024 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 9MW
2025 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 9MW
2026 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 10MW
2027 Diesel/Gasoline 1kW system (Rural) 7MW, Small Hydro 11MW
2028 Diesel/Gasoline 1kW system (Rural) 8MW, Small Hydro 11MW
2029 Diesel/Gasoline 1kW system (Rural) 8MW, Small Hydro 12MW
2030 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 12MW, Diesel/Gasoline 1kW system (Urban) 115MW

Gambia

Centralized

2012 Brikama 16MW, Batokunku 1MW
2014 Biomass 7MW, Bulk Wind (30% CF) 5MW, Solar PV (utility) 11MW
2015 CCGT 56MW, Biomass 8MW, Solar PV (utility) 13MW
2016 Biomass 8MW, Solar PV (utility) 7MW
2017 Biomass 1MW
2019 Solar PV (utility) 3MW
2021 Solar PV (utility) 2MW
2022 Solar PV (utility) 1MW
2023 Kaleta(OMVG)partGambie12% 3MW, 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% 8MW, Solar PV (utility) 2MW, Solar thermal no storage 5MW
2028 Solar PV (utility) 2MW, Solar thermal no storage 22MW
2029 Solar PV (utility) 2MW, Solar thermal no storage 30MW
2030 Solar PV (utility) 2MW, Solar thermal no storage 113MW

De-Centralized

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) 1MW
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 2MW, Diesel/Gasoline 1kW system (Urban) 7MW
2024 Diesel/Gasoline 1kW system (Urban) 4MW
2025 Diesel/Gasoline 1kW system (Urban) 1MW
2026 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
2027 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 1MW
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
2030 Diesel/Gasoline 1kW system (Rural) 1MW, PV with 2h Battery (roof top - rural) 2MW, Diesel/Gasoline 1kW system (Urban) 4MW

Ghana

Centralized

2012 Aboadze T3 phase 1 120MW, Tema T1 110MW, 10MW
2013 Sunon Asogli phase 2 327MW, Bui 342MW
2014 Aboadze T2 330MW, 50MW, Bulk Wind (30% CF) 9MW
2015 Tema T1 220MW, 100MW, Aboadze T4 (WAPP) 400MW
2022 Biomass 1MW
2023 Biomass 393MW, Solar PV (utility) 204MW
2024 Biomass 373MW, Solar PV (utility) 500MW
2025 Solar PV (utility) 359MW
2026 Biomass 223MW, Solar PV (utility) 61MW
2027 Hemang 93MW, OCGT 114MW, Biomass 10MW, Solar PV (utility) 55MW
2028 OCGT 235MW, Solar PV (utility) 65MW
2029 OCGT 255MW, Solar PV (utility) 67MW
2030 OCGT 143MW, Solar PV (utility) 12MW

De-Centralized

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

Guinea

Centralized

2012 Tombo 3 (Rehab.)2012 66MW
2013 Tombo 3 (Rehab.)2013 35MW
2014 Maneah 126MW, Biomass 20MW
2015 Baneah(Rehab) 5MW, Donkéa(Réhab) 15MW, GrandesChutes(Réhab) 27MW, Kaleta(OMVG)partGuinée40% 240MW, Biomass 21MW
2016 Biomass 22MW, Solar PV (utility) 184MW
2019 DAMEnvisagée 586MW
2020 DAMEnvisagée 586MW
2021 DAMEnvisagée 586MW
2022 DAMEnvisagée 586MW
2023 DAMEnvisagée 586MW
2027 Solar PV (utility) 45MW
2028 Solar PV (utility) 97MW
2029 Solar PV (utility) 5MW
2030 Solar PV (utility) 4MW

De-Centralized

2014 Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 6MW
2015 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 20MW
2016 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 10MW
2017 Diesel/Gasoline 1kW system (Rural) 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 16MW, Diesel/Gasoline 1kW system (Urban) 5MW
2020 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 9MW, 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
2024 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 7MW
2025 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW
2026 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW
2027 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 8MW
2028 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 8MW
2029 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 8MW
2030 Diesel/Gasoline 1kW system (Rural) 6MW, Small Hydro 6MW

Guinea-Bissau

Centralized

2012 Unserved 4MW, 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 5MW, 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 4MW, Solar PV (utility) 1MW, Solar thermal no storage 8MW
2030 Biomass 4MW, Solar PV (utility) 1MW, Solar thermal no storage 2MW

De-Centralized

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 (Rural) 1MW, PV with 1h Battery (roof top - rural) 1MW, 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

Centralized

2013 Bushrod 2 40MW, Kakata (Buchanan) 35MW
2014 OCGT 33MW, Biomass 1MW, Solar PV (utility) 37MW
2015 MountCoffee(+Viareservoir) 66MW, CCGT 63MW, Biomass 2MW
2016 OCGT 12MW, Biomass 2MW, Solar PV (utility) 52MW
2017 SaintPaul -1B 78MW, SaintPaul -2 120MW
2024 Solar PV (utility) 4MW
2027 Solar PV (utility) 2MW
2028 Solar PV (utility) 1MW
2029 Solar PV (utility) 1MW
2030 Solar PV (utility) 1MW

De-Centralized

2012 Diesel/Gasoline 1kW system (Urban) 6MW
2013 Solar PV (roof top) 1MW
2014 Small Hydro 1MW, Diesel/Gasoline 1kW system (Urban) 3MW, Solar PV (roof top) 1MW
2015 Small Hydro 2MW, 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
2022 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 6MW
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 3MW
2027 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
2028 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW
2029 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW
2030 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW

Mali

Centralized

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) 1MW
2024 Solar PV (utility) 166MW
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-Centralized

2012 Diesel/Gasoline 1kW system (Rural) 1MW
2013 Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 7MW
2014 Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 38MW
2015 Small Hydro 2MW
2016 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 10MW
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 3MW
2020 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW
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

Centralized

2012 Unserved 71MW, TAG Niamey 2 10MW, Dossou 2MW, Tillabery 2MW, Gaya 1MW, Goudel 12MW
2013 Zinder 8MW
2014 Wind 30MW, Diesel Centralized 18MW, 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 109MW
2022 Bulk Wind (30% CF) 25MW
2023 Bulk Wind (30% CF) 6MW
2024 Bulk Wind (30% CF) 6MW
2027 Bulk Wind (30% CF) 17MW, Solar PV (utility) 88MW
2028 Bulk Wind (30% CF) 6MW, Solar PV (utility) 5MW
2029 Bulk Wind (30% CF) 6MW, Solar PV (utility) 3MW
2030 Bulk Wind (30% CF) 4MW, Solar PV (utility) 2MW

De-Centralized

2013 Diesel/Gasoline 1kW system (Rural) 2MW, Diesel/Gasoline 1kW system (Urban) 12MW
2014 Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 11MW
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 2MW
2020 Small Hydro 2MW
2021 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
2022 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW
2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 3MW
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 3MW
2027 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 7MW
2028 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 8MW
2029 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 8MW
2030 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 6MW

Nigeria

Centralized

2012 GT 2012 4126MW
2013 GT 2013 1452MW
2015 CCGT 1500MW, Bulk Wind (30% CF) 363MW
2016 CCGT 1600MW
2017 Mambilla 2600MW, CCGT 1700MW
2018 Zungeru 700MW, CCGT 1800MW
2019 CCGT 1900MW
2020 CCGT 1227MW, Hydro 1000MW
2021 CCGT 240MW, Hydro 1000MW
2022 CCGT 29MW, Hydro 1000MW
2023 Hydro 1000MW
2024 Hydro 1000MW
2025 Hydro 1000MW
2026 Hydro 842MW

De-Centralized

2012 Diesel/Gasoline 1kW system (Urban) 132MW
2013 Diesel/Gasoline 1kW system (Rural) 53MW, Diesel/Gasoline 1kW system (Urban) 230MW
2014 Small Hydro 214MW, Diesel/Gasoline 1kW system (Urban) 234MW
2015 Small Hydro 79MW, Diesel/Gasoline 1kW system (Urban) 231MW
2016 Diesel/Gasoline 1kW system (Rural) 7MW, Small Hydro 128MW, Diesel/Gasoline 1kW system (Urban) 250MW
2017 Diesel/Gasoline 1kW system (Rural) 37MW, Small Hydro 92MW, Diesel/Gasoline 1kW system (Urban) 249MW
2018 Diesel/Gasoline 1kW system (Rural) 40MW, Small Hydro 95MW, Diesel/Gasoline 1kW system (Urban) 247MW
2019 Diesel/Gasoline 1kW system (Rural) 43MW, Small Hydro 107MW, Diesel/Gasoline 1kW system (Urban) 246MW
2020 Diesel/Gasoline 1kW system (Rural) 35MW, Small Hydro 119MW, Diesel/Gasoline 1kW system (Urban) 299MW
2021 Diesel/Gasoline 1kW system (Rural) 39MW, Small Hydro 152MW, Diesel/Gasoline 1kW system (Urban) 125MW
2022 Diesel/Gasoline 1kW system (Rural) 40MW, Small Hydro 153MW, Diesel/Gasoline 1kW system (Urban) 230MW
2023 Diesel/Gasoline 1kW system (Rural) 97MW, Small Hydro 168MW
2024 Diesel/Gasoline 1kW system (Rural) 48MW, Small Hydro 184MW
2025 Diesel/Gasoline 1kW system (Rural) 52MW, Small Hydro 201MW
2026 Diesel/Gasoline 1kW system (Rural) 61MW, Small Hydro 76MW
2027 Diesel/Gasoline 1kW system (Rural) 94MW, Small Hydro 353MW
2028 Diesel/Gasoline 1kW system (Rural) 100MW, Small Hydro 231MW
2029 Diesel/Gasoline 1kW system (Rural) 105MW, Small Hydro 241MW
2030 Diesel/Gasoline 1kW system (Rural) 78MW, Small Hydro 81MW

Senegal

Centralized

2012 belair 30MW
2013 Felou(OMVS)partSénégal15% 15MW, Solar PV (utility) 135MW
2014 ross betio 30MW, Biomass 62MW, Bulk Wind (30% CF) 232MW
2015 Biomass 66MW, Bulk Wind (30% CF) 29MW, Solar PV (utility) 22MW
2016 Sendou 250MW, Biomass 35MW, Bulk Wind (30% CF) 38MW
2017 Sambangalou(OMVG)partSénégal40% 51MW, Gouina(OMVS)partSénégal25% 35MW, Biomass 27MW, Bulk Wind (30% CF) 14MW
2018 Biomass 53MW, Bulk Wind (30% CF) 15MW
2019 Bulk Wind (30% CF) 16MW
2020 Bulk Wind (30% CF) 18MW
2021 Biomass 81MW, Bulk Wind (30% CF) 21MW, Solar PV (utility) 73MW
2022 Biomass 74MW, Bulk Wind (30% CF) 20MW, Solar PV (utility) 12MW
2023 Bulk Wind (30% CF) 21MW, Solar PV (utility) 2MW
2024 Biomass 47MW, Bulk Wind (30% CF) 23MW, Solar PV (utility) 24MW
2025 Bulk Wind (30% CF) 25MW, Solar PV (utility) 15MW
2026 Bulk Wind (30% CF) 25MW, Solar PV (utility) 15MW
2027 Bulk Wind (30% CF) 26MW, Solar PV (utility) 15MW
2028 Biomass 31MW, Bulk Wind (30% CF) 28MW, Solar PV (utility) 17MW
2029 Bulk Wind (30% CF) 30MW, Solar PV (utility) 18MW, Solar thermal no storage 280MW
2030 Bulk Wind (30% CF) 26MW, Solar PV (utility) 16MW, Solar thermal no storage 50MW

De-Centralized

2012 Diesel/Gasoline 1kW system (Urban) 6MW
2013 Diesel/Gasoline 1kW system (Rural) 2MW, Diesel/Gasoline 1kW system (Urban) 29MW
2014 Small Hydro 12MW, Diesel/Gasoline 1kW system (Urban) 19MW
2015 Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 17MW
2016 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 10MW, Diesel/Gasoline 1kW system (Urban) 20MW
2017 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 10MW
2018 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW, Diesel/Gasoline 1kW system (Urban) 10MW
2019 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 10MW
2020 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 11MW
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) 11MW
2023 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 7MW, Diesel/Gasoline 1kW system (Urban) 35MW
2024 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW, Diesel/Gasoline 1kW system (Urban) 3MW
2025 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 8MW
2026 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 8MW
2027 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 9MW
2028 Diesel/Gasoline 1kW system (Rural) 5MW, Small Hydro 4MW
2029 Diesel/Gasoline 1kW system (Rural) 5MW
2030 Diesel/Gasoline 1kW system (Rural) 4MW, Diesel/Gasoline 1kW system (Urban) 38MW

Sierra Leone

Centralized

2012 Unserved 2MW
2013 Diesel Centralized 6MW, Solar PV (utility) 17MW
2014 OCGT 120MW, Biomass 6MW, Solar PV (utility) 40MW
2015 Bumbuna2 40MW, CCGT 106MW, 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, Solar PV (utility) 31MW
2019 Biomass 8MW, Solar PV (utility) 48MW
2020 Benkongor1 35MW, Biomass 8MW, Solar PV (utility) 41MW
2021 Biomass 6MW
2022 Benkongor2 80MW
2024 Solar PV (utility) 10MW
2025 Benkongor3 86MW, Solar PV (utility) 1MW
2026 DAMEnvisagée 323MW
2027 Solar PV (utility) 2MW
2028 Solar PV (utility) 1MW
2029 Solar PV (utility) 1MW

De-Centralized

2012 Diesel 100 kW system (industry) 7MW, Diesel/Gasoline 1kW system (Urban) 11MW
2013 Diesel 100 kW system (industry) 35MW, Diesel/Gasoline 1kW system (Rural) 1MW, Diesel/Gasoline 1kW system (Urban) 11MW, Solar PV (roof top) 5MW
2014 Small Hydro 4MW, Solar PV (roof top) 6MW
2015 Small Hydro 2MW, Solar PV (roof top) 6MW
2016 Small Hydro 6MW, Solar PV (roof top) 6MW
2017 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 2MW
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 3MW
2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW
2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 5MW
2025 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 5MW
2026 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW
2027 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 5MW
2028 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 5MW
2029 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 2MW
2030 Diesel/Gasoline 1kW system (Rural) 5MW

Togo/Benin

Centralized

2012 Unserved 101MW, IPP_SOLAR 20MW
2013 IPP_WIND 20MW, IPP_THERMAL 57MW
2014 OCGT 48MW, Biomass 46MW
2015 MariaGleta 450MW
2017 Adjarala 147MW
2023 Biomass 33MW, Solar PV (utility) 205MW
2024 Biomass 92MW, Solar PV (utility) 78MW
2026 Biomass 69MW, Solar PV (utility) 39MW
2027 Biomass 74MW, Solar PV (utility) 21MW
2028 Biomass 119MW, Solar PV (utility) 22MW
2029 Biomass 125MW, Solar PV (utility) 23MW
2030 Biomass 15MW, Solar PV (utility) 18MW

De-Centralized

2014 Small Hydro 16MW, Diesel/Gasoline 1kW system (Urban) 55MW
2016 Small Hydro 3MW
2017 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 24MW
2018 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 3MW, Diesel/Gasoline 1kW system (Urban) 24MW
2019 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 24MW
2020 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 2MW, Diesel/Gasoline 1kW system (Urban) 7MW
2021 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 9MW
2022 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 4MW, Diesel/Gasoline 1kW system (Urban) 9MW
2023 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 6MW, Diesel/Gasoline 1kW system (Urban) 9MW
2024 Diesel/Gasoline 1kW system (Rural) 1MW, Small Hydro 9MW, Diesel/Gasoline 1kW system (Urban) 55MW
2025 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 10MW, Diesel/Gasoline 1kW system (Urban) 14MW
2026 Diesel/Gasoline 1kW system (Rural) 2MW, Small Hydro 11MW, Diesel/Gasoline 1kW system (Urban) 14MW
2027 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 11MW, Diesel/Gasoline 1kW system (Urban) 37MW
2028 Diesel/Gasoline 1kW system (Rural) 3MW, Small Hydro 12MW, Diesel/Gasoline 1kW system (Urban) 1MW
2029 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 13MW
2030 Diesel/Gasoline 1kW system (Rural) 4MW, Small Hydro 13MW, Diesel/Gasoline 1kW system (Urban) 59MW