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ELECTRICITY STRATEGY AND ACTION PLAN

UNDER UNIDO/GEF PROJECT – GEF ID-3922

PROMOTING RENEWABLE ENERGY BASED MINI GRIDS FOR PRODUCTIVE USES IN RURAL AREAS OF THE GAMBIA

Innovation by experience

REPORT INCLUDING DETAILED ELECTRICITY SCENARIOS

This project is funded by the European Union

Prepared by:

AF-MERCADOS EMI

Innovation by experience

ELECTRICITY STRATEGY AND ACTION PLAN

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ACRONYMS

ADB	African Development Bank
BOAD	Banque Ouest Africaine de Développement or West African Development Bank (WADB)
CAF	Communaute Financiere Africaine (West African) franc
CCGT	Combined Cycle Gas Turbine
CDM	Clean Development Mechanism
CFB	Circulating Fluidized Bed (a combustion technology used in power plants)
CSP	Concentrated Solar Power
ECOWAS	Economic Community Of West African States
EIA	Environmental Impact Assessment
GDP	Gross Domestic Product
GEG	Global Electric Group
GMD	Gambian Dalasi
HFO	Heavy Fuel Oil
IPP	Independent Power Plant
kV	Kilovolt, unit of potential difference, 1,000 volts
kW	Kilowatt, a unit of power (generation or demand capacity), 1,000 Watts
kWh	Kilowatt hour, a unit of electricity generated or electricity demand, 1,000 Watt hours
LFO	Light Fuel Oil
LNG	Liquefied Natural Gas
MOE	Ministry of Energy
MW	Megawatt, a unit of power (generation or demand capacity), 1,000,000 Watts
MWh	Megawatt hour, a unit of electricity generated or electricity demand, 1,000,000 Watt hours
NAWEC	National Water And Electricity Company (responsible for transmission, distribution, generation and retail supply in the Gambia)
NEA	National Environment Agency
NGO	Non-Governmental Organisation
OCGT	Open Cycle Gas Turbine
OMVG	Organisation pour la Mise en Valeur de la fleuve Gambia, or Gambia River Basin Development Organisation (planned regional hydro project)
PC	Pulverized Coal (a type of power plant)
PPA	Power Purchase Agreement
PURA	Public Utilities Regulatory Authority (regulates power sector in the Gambia)
PV	Photovoltaic
SENELEC	National Electricity Board of Senegal
toe	Tonnes oil equivalent
VOLL	Value of Lost Load
WAPP	West Africa Power Pool

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I OBJECTIVE OF THE ELECTRICITY STRATEGY

1. PURPOSE

The purpose of this task is to develop and validate an electricity strategy and action/investment plan.

This report has been tested and amended by a stakeholder workshop and associated stakeholder meetings before being finalised.

The investment plan covers the next 20 years, although the initial Action Plan for detailed enabling actions is primarily concentrated in the first five years. As well as the plan for investments, the strategy also covers technical, institutional, financial and legal issues that need to be addressed to promote renewable energy development and rural electrification, and includes capacity development measures for institutions such as MoE, PURA, NAWEC etc.

2. METHODOLOGY

The methodology we have followed to deliver the electricity strategy and an investment plan is briefly summarised in Figure 1.

Figure 1: Overview of methodology
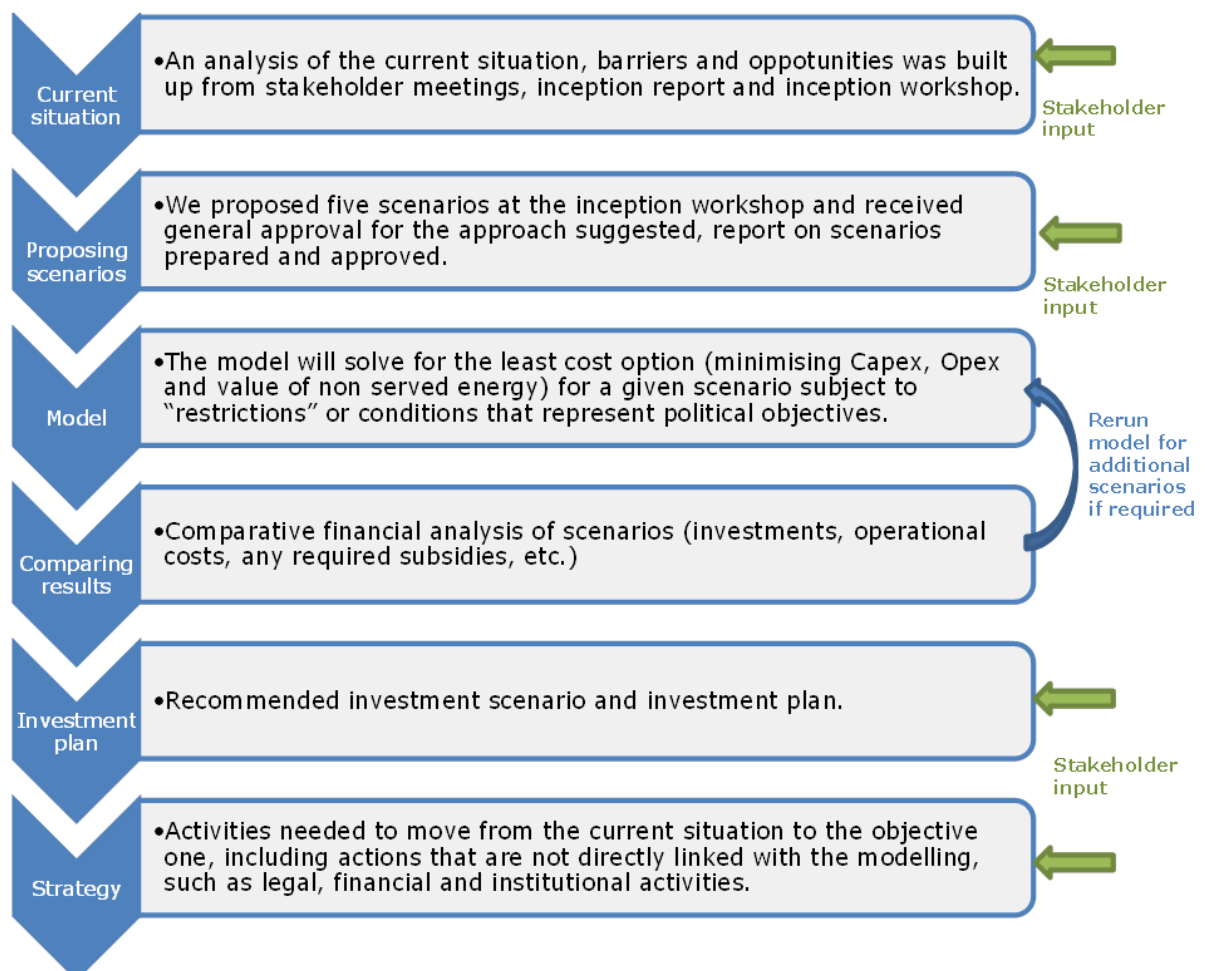
The objective in developing the scenarios was to produce a credible representation of the Gambian power system, general environment (such as evolution of fuel prices) and possible different evolutions within the simulation model environment so later alternative paths for power sector development could be assessed.

An optimisation model (applied to each scenario) was used to inform our assessment of investment requirements to satisfy electrical demand growth, achieve national electrification targets, explore the possibility of increased penetration of renewable generation and meet other energy policy objectives. More detail on the model itself is provided in Annex 1.

The scenarios are dependent on the assumptions and input data used. Therefore a high level of analysis is required to consider the risks and benefits of the scenarios and arrive at appropriate policy and investment strategies.

3. SCENARIOS ANALYSED

The objective of modelling electricity scenarios is to produce a credible representation of the Gambian power system within the simulation model environment so alternative paths for the power sector development can be assessed. This allows the costs, benefits and risks of alternative electricity strategies to be assessed.

The scenarios proposed were developed based on key issues that have been highlighted during our discussions with the Ministry of Energy and other stakeholders.

These key issues are:

- Concerns about exposure to fossil fuel prices;
- Potential for greater regional interconnectivity; and
- Desire to understand the potential role of renewable energy.

We initially chose to explore five scenarios as described in the report: "Energy Scenarios". The first is a baseline. The other four scenarios differed from this baseline in specific ways. We proposed the five scenarios at the inception workshop and received general approval for the approach suggested. These scenarios were:

- **Baseline.**
- **Higher fossil fuel prices:** Fossil fuel prices are a significant risk factor for the Gambia, as the fuel used for power plant operation is imported. While we will use central power price forecasts from the World Bank, it may be important to also consider the impacts of higher future prices on the economics of the system.
- **Interconnection for joint hydro:** We consider the impacts of the proposed OMVG project (see Section 0), which is the first stage of integration with the WAPP. This project is a regional collaboration, so there is a risk that it may not go ahead as planned. By evaluating the potential impacts of the project, we allow policy makers to understand the benefits and risks and take them into consideration in negotiations with the other parties involved in this project.
- **Renewable target:** One of the key objectives of this project is to consider the enabling framework to increase renewable electricity generation. We will consider two possibilities. The first possibility is for renewable targets to be used. This requires a certain percentage of electricity demand to be met from renewable sources, and allows the model to select the least cost option from the renewable sources available.
- **Premium for renewable in currently off-grid regions:** The second possibility is to explore the use of renewable energy to meet off-grid needs. In this scenario, there is a reduced cost to the model to choose renewables in off-grid regions, to represent a premium paid to projects in these regions. This shows the impact of a policy of helping to support rural electrification, in a similar way to the current GEF-UNIDO projects.

The renewables target scenario has an endogenous cost of renewable technologies and picks the least cost renewable technologies and location to meet the target. In the off-grid scenario the choice of renewable location is exogenous (we pick winners).

We also added the following scenarios as the modelling work progressed, in order to give a stronger view of the opportunities and risks:

- **Transmission:** Some of the "automatic" network investment decisions of the model were not optimal from a technical viewpoint. We forced an investment scenario that would use higher voltage lines.
- **With and without coal:** We found coal to be a good economic choice for the Gambia. However, coal plants come in big "chunks" of investment. These present a relatively high level of technical risk, as if a plant is down there needs to be an alternative source of generation. We therefore constrained down the coal option in some scenarios. (In other words, the coal plant size is not consistent with technical reliability requirements.)
- **VOLL:** PURA asked a question about the levels of VOLL. To show the relative impact of different VOLL assumptions, we looked at a scenario with a higher VOLL (US$1,500).

Other changes since the scenarios report are the treatment of transmission losses, and some changes to generation costs see Annex 2 and 3 for more detail.

Following the stakeholder workshop, we developed three illustrative scenarios to show possible development of the Gambian power sector. These are described in Section III

II SCENARIO RESULTS

1. DESCRIPTION OF THE FIRST ROUND OF SCENARIOS

Tables and figures presenting the input data are provided in Annex 2 for the baseline (shared) inputs. Variable inputs for each of the scenarios are detailed in Annex 3.

All optimisation models rely on the availability of sufficient and reliable input data in order to produce robust outputs. In the absence of such data, estimates must be made. This document describes the model and data assumptions that are used in this study. We describe the assumptions we have made in more detail in the Annexes, but some of the key issues are highlighted here.

1.1. KEY GAPS IN DATA

Perhaps the most significant data that is not available is information on current electricity usage. More precisely, we do not have access to fine temporal resolution data at each load point on the network. This data is important in calculating production costs and generation and transmission capacity needs. NAWEC has not been able to provide this information. We recommend that better data on hourly demand and generation is gathered and reported by NAWEC in the future, to allow more effective planning.

We will represent the demand using a Load Duration Curve. Normally this would include at least three or four demand blocks and reflect seasonal and monthly changes in demand (for example during the rainy season). Limited data is available on the shape of demand, so we have been forced to simplify this duration curve to only show peak and average demand requirements.

Information on current generation plants and on the current technical transmission losses is limited. We have made generic assumptions following international standards in the region, but these may need to be adjusted later if information is available. For example, many Gambian plants are relatively old, refurbished and may not have been maintained appropriately due to cash constraints. If these existing plants are less economic than represented here, the economics of replacing them may be more attractive.

There is also limited information on the real costs of installing new power plants in the Gambia. Where possible, we have used real data from feasibility studies (for example, GEF UNIDO). Otherwise, we have used international standards, where possible based on West Africa.

1.2. ASSUMPTIONS

As mentioned above, we have made assumptions about the level of existing and suppressed demand, about the shape of demand, about demand growth and about the location of demand. This information is currently unknown in the Gambia. We have also made an assumption that all electricity users will have some access to electricity (microgrid or as part of an interconnected system) by 2025 following the policy decisions on this aspect. The demand assumption is broadly consistent with WAPP projections to 2025 (slightly lower than the base case assumptions in WAPP 2011).

Where information on actual costs in the Gambia is unknown, we have used international comparators, whenever possible from the West Africa region.

In our analysis of the transmission network costs, we have only looked at the costs of overhead lines and not included the costs of substations, transformers and other transmission equipment. The costs are based on feasibility studies in the Gambia, but real costs would be increased by the need for this additional equipment, and also for better control and monitoring of a growing network. A full feasibility study would be required to properly assess these costs at the point of implementing projects. Therefore, our analysis should be taken as a good but first approximation.

At this stage, the project is most interested in the comparative costs and benefits of different scenarios, in order to choose the most appropriate strategy going forwards. In the scenarios we are considering, there will not be significant differences in distribution investment because demand is the same for all scenarios. In the final version of this report we provide some indicative values of investments needed to cover the distribution component of costs, based on global indicators. Precise actual costs would always need to be based on a detailed technical engineering plan.

The forecasts of future primary fuel prices are based on World Bank forecasts, with our own elaboration where necessary.

1.3. RISKS

Results from any optimisation model that looks to the future, which is hugely uncertain, must be viewed with a degree of realism and caution. Below are some of the key risks that are present given this uncertainty and how this impacts on model results:

1. **Demand** is a key uncertainty in this analysis. If demand growth is higher than forecast then there may be inadequate available generation capacity or transmission network to meet customer energy needs, particularly during peak periods. This will harm the public and interrupt economic activity. On the other hand, if demand growth is lower than forecast, then a proportion of capacity will be underused, putting an additional cost on tariffs that would have been avoided with perfect foresight.

2. **Electrification rates and distribution of demand** current distribution of demand is uncertain, and much demand is currently unserved. If our assumptions about the level and location of demand are incorrect, then the appropriate strategy may be different.

3. The primary **fuel prices** used in power system operation are a key consideration when projecting investment requirements. More precisely, the optimal mix of generation capacity depends heavily on the running costs of each power plant type. If fuel prices are higher than forecast, then there is a risk that production costs become more expensive, particularly if the plant mix is powered by fuel types with prices that are correlated (e.g., fuel oil, gasoil and gas). This is a significant risk and is addressed in the "high fossil fuel price" scenario.

4. Generation and transmission **capacity investment costs** can have a large impact on what actions are taken to meet power system investment needs. For instance, if construction lead time for a power plant increases by a year, this will increase the interest accumulated during construction, which will ultimately increase tariffs for consumers or may increase load shedding (value of non-supplied energy). These impacts are more severe with capital intensive and long lead time capacity (e.g., coal units are typically more expensive to build relative to diesel units; however production costs for coal are typically lower so there is less impact of fuel price risk).

5. The model cannot represent **political risks**, for example the uncertainty inherent in regional projects like the OMVG hydro project. For this reason, we consider this as a separate scenario, and by considering it we may allow policy makers to judge the relative importance of the project.

It is important to note that owing to the possible inaccuracies of data estimation, the model results should be interpreted with a degree of caution. For instance, the absolute values produced by the model will not provide robust estimates for year-on-year total system costs if input values such as demand and production costs cannot be validated against actual measurement data.

On the other hand the model is useful to compare relative changes in model outputs when testing the significance of key uncertainties such as higher fuel prices or the impact of policy goals such as renewables targets.

2. FIRST ROUND OF SCENARIO RESULTS

For each scenario, the model will select the optimal trade-off between generation and transmission investment, and its optimal time deployment during the entire scenario horizon.

In this section, we review the model's choice of generation in each scenario and critically assess whether each is an appropriate option for the Gambia. The costs and key parameters of all the scenarios are summarised and compared in Section 3 in Table 1 and Table 2.

2.1. BASELINE

Figure 2 and Figure 3 show investment in generating plant and generation in the baseline scenario. The baseline selects an option to build coal in the Greater Banjul area. This has the advantage of low operational costs. However, the coal unit is a very large proportion of the supply in the Greater Banjul area. This is unlikely to be desirable, as in the event of maintenance downtime or unanticipated unavailability, either large amounts of back-up generation would be required or the whole Greater Banjul area would be without supply.

The remaining plant is primarily HFO and LFO, with a little solar PV and wind.

The choice of generation available to the model is quite "lumpy" and comes in discrete sizes. Solar PV and wind entry is more flexible. This means capacity growth is not necessarily smooth with respect to demand. It also means wind and solar can play an important role in meeting smaller increases in demand.

Figure 2: Baseline scenario generation new build (MW)

Generation investment MW per year

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LFO new	0.00	0.00	0.00	0.00	0.00	7.44	17.93	5.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	10.00	0.00	0.00
HFO new	0.00	0.00	9.00	17.80	0.00	20.00	0.00	0.00	0.00	20.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00	0.00	0.00
Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SolarPV	0.00	0.00	0.00	0.00	0.81	0.42	0.46	0.51	0.53	0.58	0.62	0.67	0.73	0.78	0.84	0.91	0.35	0.37	0.38	0.40	0.42	0.31	0.00
Wind	0.00	0.00	0.00	0.00	1.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.55	0.00	0.00

Figure 3: Baseline scenario generation (MWh)

Generation MWh

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SolarPV	-	-	-	-	1,416	2,147	2,962	3,845	4,780	5,793	6,906	8,068	9,342	10,71	12,22	13,78	14,39	15,03	15,74	16,40	17,13	17,68	17,73
Wind	-	-	-	98.55	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	7,262	7,262	7,164	7,184
Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HFO new	-	-	20,93	48,72	63,46	122,4	153,3	199,1	225,4	175,0	203,9	215,7	229,1	242,6	262,7	314,3	312,6	355,9	426,6	454,3	521,1	560,6	603,5
HFO existing	208,3	217,8	202,2	206,8	218,4	240,6	261,5	271,1	275,6	3,795	4,095	4,593	3,168	25,91	48,15	41,07	81,69	74,74	38,64	38,54	-	-	-
LFO new	-	-	-	-	-	6,101	39,90	69,60	97,79	70,94	85,49	91,84	98,76	106,2	114,4	122,2	127,7	140,9	153,1	165,0	174,7	188,6	202,8
LFO existing	6,023	6,192	6,385	8,208	8,507	5,086	12,40	12,36	12,36	4,660	4,731	4,718	4,819	4,819	4,832	4,819	4,819	-	-	-	-	-	-
OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 70MW	-	-	-	-	-	-	-	-	-	444,8	469,6	493,0	519,0	521,2	522,6	521,2	521,2	521,2	522,6	521,2	521,2	521,2	522,6
Coal 125MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

The model builds transmission lines as shown in Figure 4:

- In 2015/16 – the model selects links Brikama-Bijilo (33kV), Western-Brikama (33kV), Soma-Lower (33kV), Farrafenni-North 2 (33kV), Central 2-Upper (33kV), Njaba Kunda-North 2, Barra demand-North 1, Kerewan-North1 and Janjanburreh-UnconnectedCentral2 (33kV)
- Finally, in 2030-2, there are investments in Kuar-Kuntar (132kV).

It therefore chooses to join some of the currently isolated microgrid systems together into larger systems. However, overall the system remains separated.

Figure 4: Baseline scenario transmission build
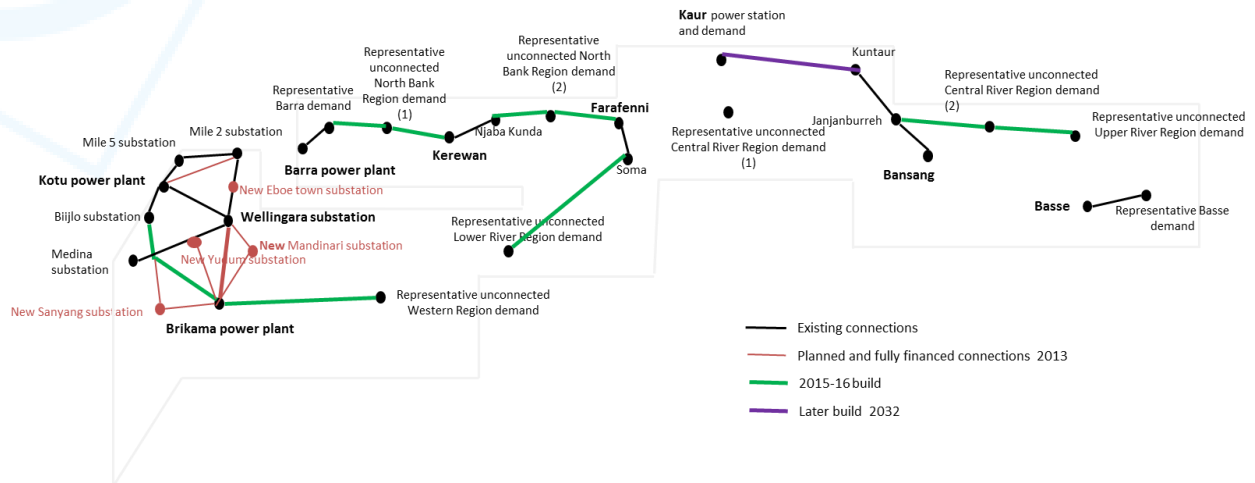
2.2. BASELINE (NO COAL)

Due to our concerns about the first baseline scenario, we chose to run a second baseline, this time preventing coal build. In this scenario, most demand is met my HFO and LFO. More significant amounts of wind and solar PV are also built. The generating plant built is shown in Figure 5, and the generation is shown in Figure 6.

This has the advantage of not relying on a single generator. However, the disadvantage is that this scenario is heavily reliant on oil. This is the case with the current generation mix in the Gambia, and has caused concern because of the volatile prices.

Figure 5: No coal baseline scenario generation new build (MW)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LFO new	0.00	0.00	0.00	0.00	0.00	25.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	15.00	0.00	0.00	0.00
HFO new	0.00	0.00	9.00	17.80	20.00	0.00	0.00	0.00	0.00	20.00	0.00	0.00	26.81	0.00	0.00	20.00	20.00	0.00	0.00	20.00	20.00	0.00	0.00
Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SolarPV	0.00	0.00	0.00	0.00	0.66	0.33	0.36	0.40	0.42	0.46	0.49	0.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	1.36	0.00	0.00	0.00	0.00	0.00	0.00	15.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 6: No coal baseline scenario generation (MWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Solar PV	-	-	-	-	1,155	1,733	2,379	3,077	3,818	4,619	5,501	6,421	6,421	6,421	6,438	6,421	6,421	6,421	6,438	6,421	6,421	6,421	6,438
Wind	-	-	-	98.55	990.9	990.9	993.6	990.9	990.9	990.9	993.6	11,31	11,31	11,31	11,34	11,31	11,31	11,31	11,34	11,31	11,31	11,21	11,24
Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HFO new	-	-	16,57	38,91	93,45	140,3	185,4	216,0	239,2	323,3	363,1	381,6	564,7	598,2	626,7	701,4	787,3	859,8	941,4	974,3	1,181	1,215	1,258
HFO existing	208,3	217,8	206,6	216,6	203,4	228,1	234,8	261,4	270,8	288,8	304,0	308,3	165,3	174,4	193,2	168,6	123,7	87,97	38,64	32,10	-	-	-
LFO new	-	-	-	-	-	21,70	38,97	62,58	87,27	60,09	72,44	76,62	81,32	86,23	91,39	96,33	100,3	111,5	122,3	148,9	36,43	55,37	65,18
LFO existing	6,023	6,192	6,385	8,208	6,536	5,086	12,40	12,36	12,36	4,692	4,731	4,819	4,819	4,819	4,832	4,819	4,819	-	-	-	-	-	-
OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 70MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 125MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

As Figure 7 shows, more transmission lines are built and earlier than the initial baseline scenario. The system eventually becomes fully interconnected:

- In 2015/16 – the model selects links Brikama-Bijilo (33kV), Western-Brikama (33kV), Soma-Lower (33kV, Central-Kuar (33kV), Basse demand-Upper (33kV) Farrafenni-North 2 (33kV), Njaba Kunda-North 2 Barra demand- North 1 and Kerewan-North1.
- There are more transmission investments in 2025-6: Central 2-Upper (33kV), Kuar- Kuntar (132kV).
- Finally, in 2030-2, there are investments in Basang-Basse (33kV), Lower-Western (132kV), Western-Wellingara (33kV) and Farrafenni-Kuar (132kV).

Figure 7: No coal baseline scenario transmission build

2.3. HIGH FUEL

High fuel prices are considered to be a significant risk for the Gambia, and we wanted to see which option the model chose to minimise costs when fossil fuel prices were high (note that in this scenario no coal investment was permitted).

Figure 8: High fuel cost scenario generation new build (MW)

Generation investment MW per year

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LFO new	0.00	0.00	0.00	0.00	0.00	10.00	10.00	15.00	5.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HFO new	0.00	0.00	9.00	17.80	20.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.76	20.00	20.00	0.00	0.00	20.00	0.00	0.00	0.00	0.00	0.00
Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.00	0.00	0.00	0.00	0.00
Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SolarPV	0.00	0.00	0.00	0.00	1.28	0.42	0.46	0.51	0.53	0.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	1.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 9: High fuel cost scenario generation (MWh)

Generation MWh

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SolarPV	-	-	-	-	2,243	2,974	3,792	4,671	5,607	6,619	6,638	6,619	6,619	6,619	6,638	6,619	6,619	6,619	6,638	6,619	6,619	6,619	6,638
Wind	-	-	-	98.55	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	892.4	894.8
Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	298,6	297,8	297,8	297,8	298,6
Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HFO new	-	-	25,04	41,88	75,51	111,5	132,6	195,9	279,4	299,7	329,2	333,2	525,4	604,1	695,3	728,5	782,5	945,6	800,4	817,0	888,2	926,3	967,7
HFO existing	208,3	217,8	198,1	213,7	221,4	229,3	259,8	260,3	260,5	281,9	306,6	308,3	153,4	152,9	182,9	192,7	192,7	114,6	7,075	29,38	-	-	-
LFO new	-	-	-	-	1,008	30,59	60,83	87,17	69,94	88,35	91,32	127,3	128,3	110,4	57,19	64,80	62,87	32,27	39,78	47,44	56,22	70,91	74,72
LFO existing	6,023	6,192	6,385	8,208	6,536	6,536	6,303	6,337	3,759	6,676	12,43	12,40	12,40	12,40	4,733	4,819	4,819	-	-	-	-	-	-
OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 70MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 125MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

In this scenario, the model chose to build a large biomass plant to reduce exposure to the high fuel prices towards the end of the scenario. This is an interesting choice, but it is worth noting that international biomass prices are highly influenced by fossil fuel prices in reality. Unless the Gambia had a guaranteed cost for biomass fuel, this may not be such a successful strategy in reducing exposure to fossil fuel prices as it appears in this scenario.

Transmission lines are built later in this scenario, and fewer of the microgrids are connected:

- In 2020-25 – the model selects links Brikama-Bijilo (33kV), Western-Brikama (33kV), Soma-Lower (33kV), Central-Kuar (33kV), Farrafenni-North 2 (33kV), Njaba Kunda-North 2 Barra demand- North 1, Kerewan-North1 and BasseDemand-Basse-33kV.

Figure 10: High fuel cost scenario transmission build
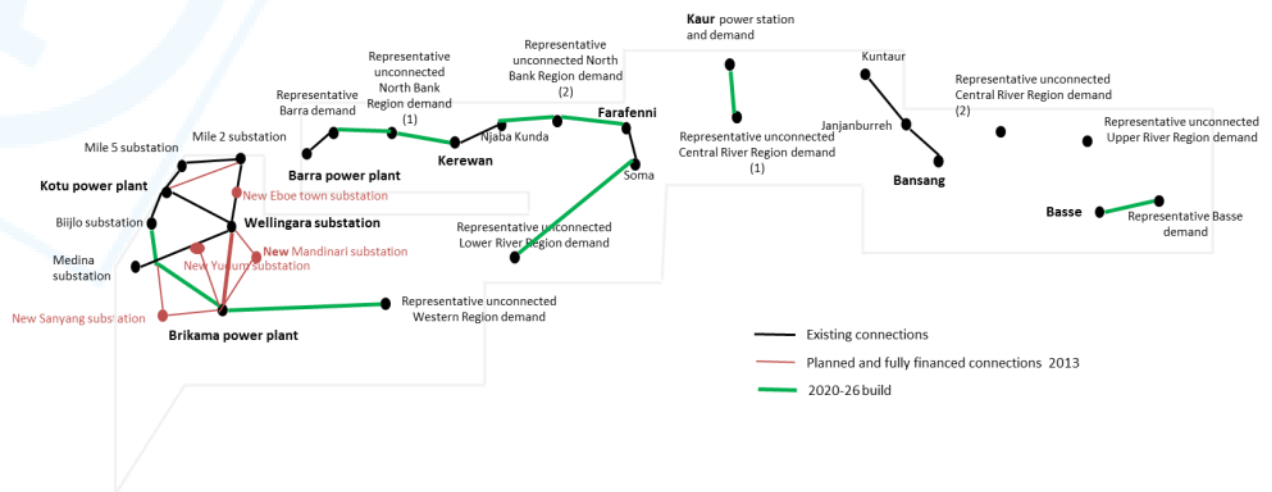
2.4. HIGH VOLL

PURA were interested in the impact of a higher VOLL on the scenarios. In all other scenarios the VOLL is $800/MWh, in this scenario it is increased to $1,500/MWh.

Capacity and generation are shown in Figure 11 and Figure 12.This scenario builds more HFO and LFO generation than in the baseline (no coal) scenario. It builds less intermittent renewable generation.

Figure 11: High VOLL scenario generation new build (MW)

Generation investment MW per year

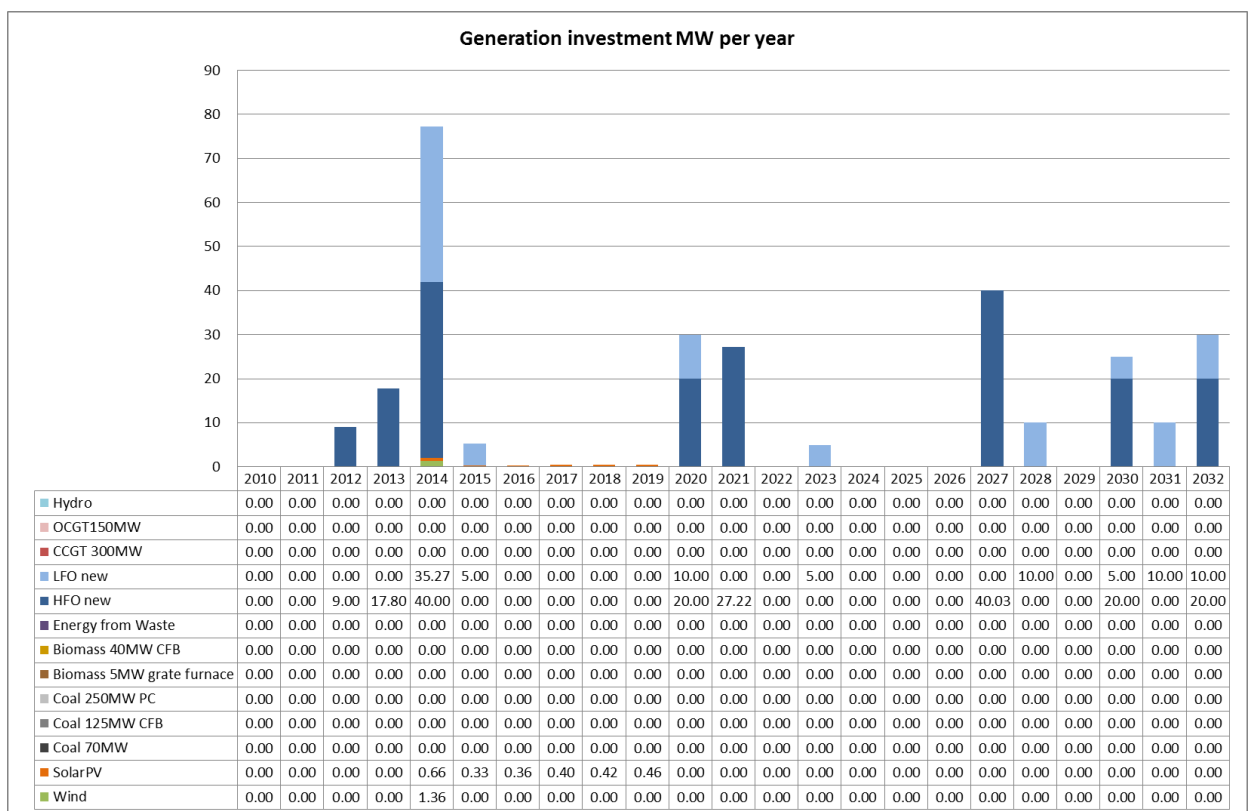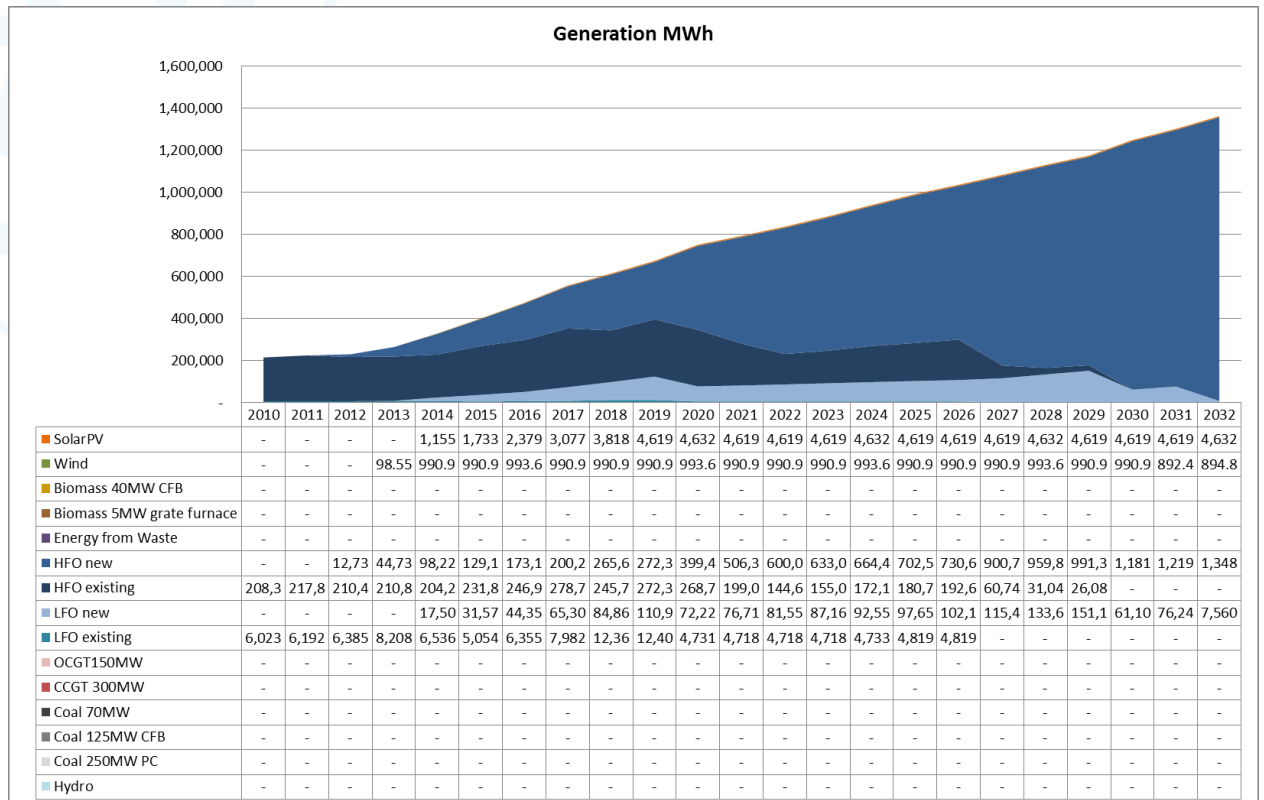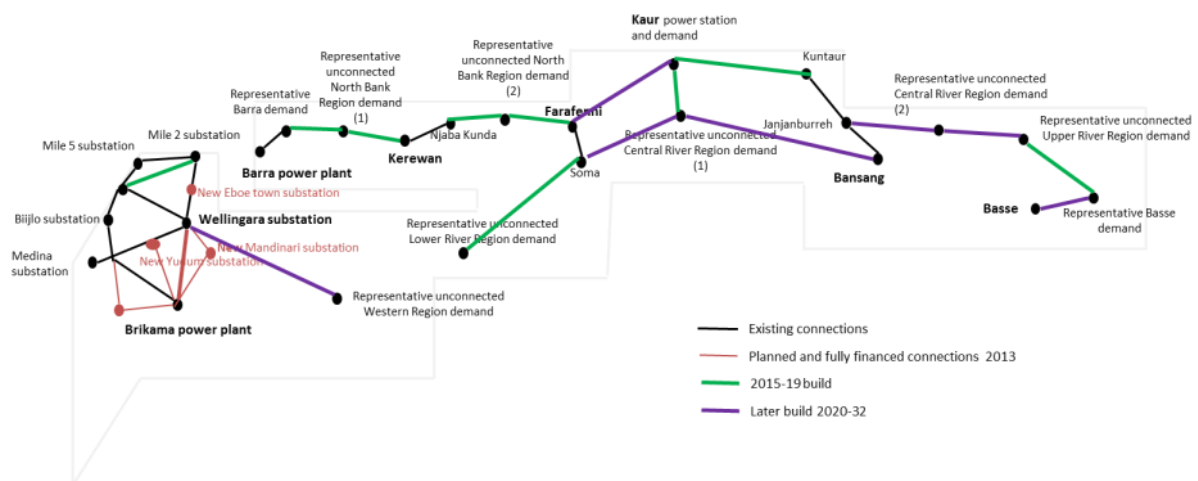|	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LFO new	0.00	0.00	0.00	0.00	0.00	35.27	5.00	0.00	0.00	0.00	10.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	10.00	0.00	5.00	10.00	10.00
HFO new	0.00	0.00	9.00	17.80	40.00	0.00	0.00	0.00	0.00	0.00	20.00	27.22	0.00	0.00	0.00	0.00	0.00	40.03	0.00	0.00	20.00	0.00	20.00
Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SolarPV	0.00	0.00	0.00	0.00	0.66	0.33	0.36	0.40	0.42	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	1.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 12: High VOLL scenario generation (MWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SolarPV	-	-	-	-	1,155	1,733	2,379	3,077	3,818	4,619	4,632	4,619	4,619	4,619	4,632	4,619	4,619	4,619	4,632	4,619	4,619	4,619	4,632
Wind	-	-	-	98.55	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	892.4	894.8
Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HFO new	-	-	12,73	44,73	98,22	129,1	173,1	200,2	265,6	272,3	399,4	506,3	600,0	633,0	664,4	702,5	730,6	900,7	959,8	991,3	1,181	1,219	1,348
HFO existing	208,3	217,8	210,4	210,8	204,2	231,8	246,9	278,7	245,7	272,3	268,7	199,0	144,6	155,0	172,1	180,7	192,6	60,74	31,04	26,08	-	-	-
LFO new	-	-	-	-	17,50	31,57	44,35	65,30	84,86	110,9	72,22	76,71	81,55	87,16	92,55	97,65	102,1	115,4	133,6	151,1	61,10	76,24	7,560
LFO existing	6,023	6,192	6,385	8,208	6,536	5,054	6,355	7,982	12,36	12,40	4,731	4,718	4,718	4,718	4,733	4,819	4,819	-	-	-	-	-	-
OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 70MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 125MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 13: High VOLL scenario transmission build

Transmission line investment is shown in Figure 13:

- In 2015-21 – the model selects links Kotu-Mile2 (reinforcement), Western-Brikama (33kV), Soma-Lower (33kV), Central-Kuar (33kV), Basse demand-Upper (33kV), Farrafenni-North 2 (33kV), Njaba Kunda-North 2, Barra demand-North 1 (33kV), Kuar-Kuntar (132kV), Central 2-Upper (33kV) and Kerewan-North1 (33kV).
- Finally, in 2030-2, there are investments in Western-Wellingara (33kV), Farrafenni-Kuar (132kV), Soma-Central 1 (132kV), Basse demand-Basse (33kV) and Janjanburreh-Central 2 (33kV).

2.5. RENEWABLE TARGET

We then considered the impact of a renewable target on the model build. The target was for 5% of demand to be met by renewables by 2020 and 10% by 2030.

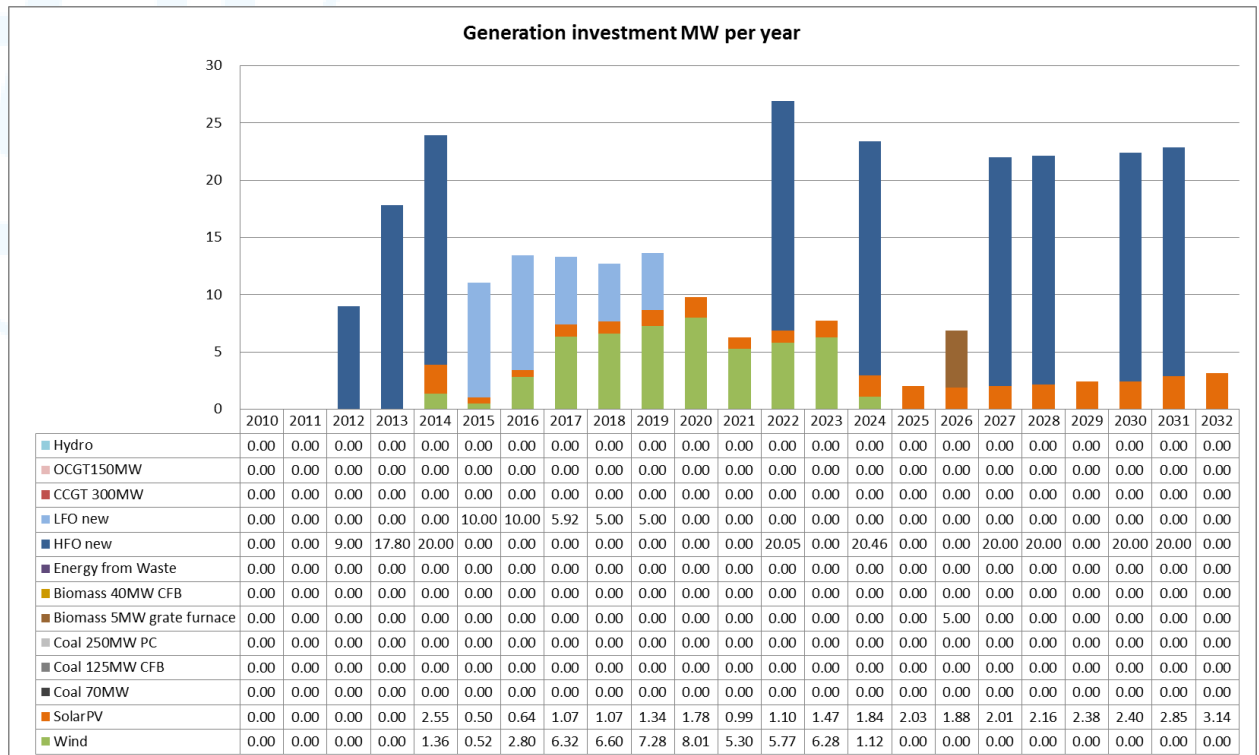**Figure 14: Renewable target scenario generation new build (MW)**

Generation investment MW per year

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LFO new	0.00	0.00	0.00	0.00	0.00	10.00	10.00	5.92	5.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HFO new	0.00	0.00	9.00	17.80	20.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.05	0.00	20.46	0.00	0.00	20.00	20.00	0.00	20.00	20.00	0.00
Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SolarPV	0.00	0.00	0.00	0.00	2.55	0.50	0.64	1.07	1.07	1.34	1.78	0.99	1.10	1.47	1.84	2.03	1.88	2.01	2.16	2.38	2.40	2.85	3.14
Wind	0.00	0.00	0.00	0.00	1.36	0.52	2.80	6.32	6.60	7.28	8.01	5.30	5.77	6.28	1.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 15: Renewable target scenario generation (MWh)

Generation MWh

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SolarPV	-	-	-	-	4,463	5,344	6,483	8,337	10,21	12,56	15,72	17,42	19,35	21,93	25,22	28,71	31,99	35,52	39,40	43,47	47,67	52,66	58,32
Wind	-	-	-	98.55	990.9	1,330	3,176	7,319	11,65	16,44	21,76	25,19	28,98	33,10	33,93	33,84	33,84	33,84	33,93	33,84	33,84	33,74	33,83
Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	612.0	36,97	24,40	30,35	36,78	37,23	37,33
Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HFO new	-	-	32,59	47,29	71,39	123,9	172,4	188,4	223,0	243,9	271,7	284,2	427,4	447,9	528,5	550,4	583,0	723,5	896,0	916,4	980,3	1,118	1,164
HFO existing	208,3	217,8	190,5	208,3	225,5	238,5	247,6	284,2	277,2	284,1	287,0	300,2	183,0	192,7	147,7	159,9	157,4	115,6	32,66	37,70	-	-	-
LFO new	-	-	-	-	-	14,95	35,14	53,94	78,21	102,1	127,6	138,7	150,1	161,6	174,7	187,4	197,0	127,8	94,73	104,4	120,3	44,23	51,51
LFO existing	6,023	6,192	6,385	8,208	6,536	5,086	4,799	12,36	12,36	12,40	12,43	12,40	12,40	12,40	12,43	12,40	12,40	-	-	-	-	-	-
OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 70MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 125MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 14 and Figure 15 show the capacity and generation in the renewable target scenario. In this case a mixture of wind, solar PV and biomass was selected to meet the target, and the remainder of generation was from HFO and LFO.

Transmission investment is shown in Figure 15:

- In 2015-21 – the model selects links Brikama-Bijilo (33kV), Western-Brikama (33kV), Basse demand-Upper (33kV) Farrafenni-North 2 (33kV), Central 2-Upper (33kV), Njaba Kunda-North 2 Barra demand-North 1, Kaur-Kuntar, Kaur-Central1 and Kerewan-North1.

- There are more transmission investments in 2028 and 2030 to connect Farrafenni to Kuar and Bansang-Basse

Figure 16: renewable target scenario transmission build
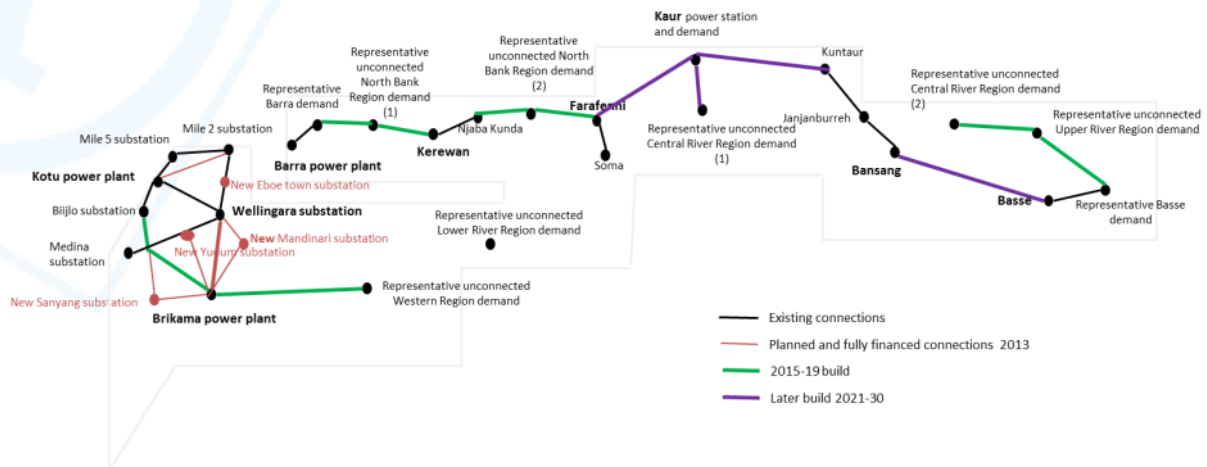
2.6. OFF-GRID FIT

When renewables are being used to supply offgrid areas, the biomass option is no longer available.

The model selects a mixture of solar PV and wind in this scenario. Detail of the feed-in-tariffs paid to these technologies is given in Annex 4. Build of renewables is earlier in response to a favourable tariff.

Figure 17: Off-grid FIT scenario generation (MWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
■ SolarPV	-	-	-	-	1,155	6,179	10,37	11,05	11,79	12,59	12,63	12,59	12,59	12,59	12,63	12,59	12,59	12,59	14,20	14,16	14,16	14,16	14,20
■ Wind	-	-	98.55	14,01	28,66	33,93	37,37	38,46	40,41	40,52	40,41	40,41	40,52	40,41	40,41	40,41	40,52	40,41	40,41	40,31	40,42
■ Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ HFO new	-	-	16,49	57,12	82,94	121,3	158,6	173,4	216,8	242,7	264,7	279,5	456,9	567,9	602,4	621,4	732,8	841,9	946,7	1,063	1,145	1,190	1,286
■ HFO existing	208,3	217,8	206,7	198,4	213,9	218,5	236,6	284,1	273,3	280,9	295,8	308,3	160,6	171,1	189,8	192,7	149,1	82,99	32,61	38,54	-	-	-
■ LFO new	-	-	-	-	8,910	14,95	21,69	40,67	58,91	82,97	112,2	124,1	137,0	79,16	84,48	114,3	94,89	102,6	90,07	22,43	30,50	39,11	4,007
■ LFO existing	6,023	6,192	6,385	8,208	6,536	6,229	4,799	5,864	12,36	12,40	12,43	12,40	12,40	4,718	4,832	4,819	4,819	-	-	-	-	-	-
■ OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ Coal 70MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ Coal 125MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 18: Off-grid feed-in-tariff scenario generation new build (MW)

Generation investment MW per year

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
■ Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ LFO new	0.00	0.00	0.00	0.00	10.46	0.00	0.00	10.00	5.00	0.00	5.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ HFO new	0.00	0.00	9.00	17.80	20.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.22	20.00	0.00	0.00	20.00	20.00	0.00	20.00	20.00	0.00	20.00
■ Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ SolarPV	0.00	0.00	0.00	0.00	0.66	2.87	2.38	0.40	0.42	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.90	0.00	0.00	0.00	0.00
■ Wind	0.00	0.00	0.00	0.00	21.19	22.29	7.88	5.61	1.42	2.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 19: Off-grid FIT scenario transmission build

Transmission build is similar to the baseline, see Figure 19, but there is lower investment overall, as more microgrids are supplied by renewables:

- In 2015-19 – the model selects links Brikama-Bijilo (33kV), Western-Brikama (33kV), Soma-Lower (33kV, Central-Kuar (33kV), Basse demand-Upper (33kV) Farrafenni-North 2 (33kV), Njaba Kunda-North 2 Barra demand-North 1 and Kerewan-North1. (Exactly as baseline, but spread over a longer period.)
- Finally, in 2030-2, there are investments in Basang-Basse (33kV), Central 2-Upper (33kV) and Farrafenni-Kuar (132kV).

2.7. OMVG

The OMVG scenario allows the planned regional hydro project to be connected into Soma from 2020. The hydro project provides a low cost contribution to meeting demand. Much of the rest of demand is met by HFO and LFO, with some solar PV (see Figure 20 and Figure 21).

In this scenario more 132kV lines are built to connect the new generation to the demand in the Greater Banjul area, as shown in Figure 22. The whole country becomes interconnected:

- In 2015-19 – the model selects links Brikama-Bijilo (33kV), Western-Brikama (33kV), Soma-Lower (33kV, Basse demand-Upper (33kV), Central 2-Upper (33kV), Farrafenni-North 2

(33kV), Njaba Kunda-North 2 Barra demand-North 1 and Kerewan-North1. (Faster investment than baseline.)

- In 2020, at the same time at the OMVG project is connected, there are investments in 132kV lines from Soma to Wellingara.
- Then until 2031, further lines are built Basang-Basse (33kV) and Janjanberreh-Central2 (33kV), Lower-Wellingara 132kV, Kuar-Kuntar (132kV) and Farrafenni to Kuar (132kV).

Figure 20: OMVG scenario generation new build (MW)

Generation investment MW per year

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LFO new	0.00	0.00	0.00	0.00	10.00	0.00	0.00	15.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HFO new	0.00	0.00	9.00	17.80	20.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00	0.00	0.00	20.00	20.00	0.00	20.00	0.00	0.00
Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SolarPV	0.00	0.00	0.00	0.00	0.81	0.42	0.46	0.51	0.53	0.58	0.62	0.67	0.73	0.78	0.84	0.91	0.35	0.37	0.38	0.40	0.42	0.31	0.00
Wind	0.00	0.00	0.00	0.00	1.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 21: OMVG scenario generation (MWh)

Generation MWh

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SolarPV	-	-	-	-	1,416	2,147	2,962	3,845	4,780	5,793	6,906	8,068	9,342	10,71	12,22	13,78	14,39	15,03	15,74	16,40	17,13	17,68	17,73
Wind	-	-	-	98.55	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	892.4	894.8
Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HFO new	-	-	20,54	50,67	86,12	147,3	180,0	202,4	232,5	259,9	136,2	168,1	252,1	297,5	391,7	411,8	433,1	574,4	715,8	743,8	854,0	897,0	917,4
HFO existing	208,3	217,8	202,6	204,9	210,8	222,9	242,9	278,4	281,9	288,7	188,2	193,3	160,0	181,4	112,2	127,9	154,5	65,77	38,64	38,54	-	-	-
LFO new	-	-	-	-	8,910	14,95	21,69	58,65	82,33	107,7	65,90	68,71	71,83	54,70	65,56	76,67	71,98	58,04	2,988	20,44	2,988	7,535	37,18
LFO existing	6,023	6,192	6,385	8,208	6,536	6,577	12,40	12,36	12,36	12,40	3,242	3,234	3,234	3,234	3,242	4,819	4,576	-	-	-	-	-	-
OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 70MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 125MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-	-	-	-	386,4	385,4	385,4	385,4	386,4	385,4	385,4	385,4	386,4	385,4	385,4	385,4	386,4

Figure 22: OMVG scenario transmission build

2.8. OMVG (ALLOWING COAL)

The OMVG scenario offers an interesting opportunity to export power using the same lines that the hydro is imported on. We therefore chose to allow coal to build in a second run of the OMVG scenario to explore the results. The generation and capacity are shown in Figure 23 and Figure 24.

Once again, transmission lines are built to interconnect the whole country:

- In 2015-17 – the model selects links Brikama-Bijilo (33kV), Western-Brikama (33kV), Soma-Lower (33kV), Central 2-Upper (33kV), Farrafenni-North 2 (33kV), Janjanburreh-Central2 (33kV), Njaba Kunda-North 2 and Basse Demand-Upper (33kV).
- In 2019-22 the model builds Soma-Farrafenni (132kV), Central-Kuar (33kV), Kuar-Kuntar (132kV), Kerewan-North1, UnconnectedNorth1-BarraDemand (132kV) and Janjanburreh-Kuntaur (132kV).
- Lower-Western (132kV) and BasseDemand-Basse-33kV.

Figure 23: OMVG and coal scenario generation new build (MW)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LFO new	0.00	0.00	0.00	0.00	0.00	5.00	10.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HFO new	0.00	0.00	9.00	17.80	0.00	20.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00	40.00	60.00	20.00
Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SolarPV	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	1.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 24: OMVG and coal scenario generation (MWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
■ SolarPV	-	-	-	-	161.7	161.7	162.1	161.7	161.7	161.7	162.1	161.7	161.7	161.7	162.1	161.7	161.7	161.7	162.1	161.7	161.7	161.7	162.1
■ Wind	-	-	-	98.55	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	892.4	894.8
■ Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ HFO new	-	-	12,99	51,70	72,47	126,0	200,6	135,9	156,3	181,8	20,13	27,99	12,96	29,76	53,17	96,97	121,4	167,3	236,8	289,4	373,7	419,1	474,0
■ HFO existing	208,3	217,8	210,1	203,8	209,3	243,2	231,2	3,106	3,504	3,590	4,036	4,540	3,168	25,91	48,18	55,09	72,95	70,01	38,64	38,54	-	-	-
□ LFO new	-	-	-	-	2,497	18,86	27,04	26,04	41,24	64,60	276.2	720.7	2,004	2,390	2,390	2,390	2,390	2,390	2,390	2,390	2,390	2,390	2,390
□ LFO existing	6,023	6,192	6,385	8,208	8,507	3,908	3,757	9,816	9,816	12,40	102.1	235.7	235.7	235.7	235.7	235.7	235.7	-	-	-	-	-	-
■ OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
■ Coal 70MW	-	-	-	-	-	-	-	403,7	425,0	444,8	469,6	493,0	519,0	521,2	522,6	521,2	521,2	521,2	522,6	521,2	521,2	521,2	522,6
■ Coal 125MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
□ Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
□ Hydro	-	-	-	-	-	-	-	-	-	-	327,9	338,1	385,4	385,4	386,4	385,4	385,4	385,4	386,4	385,4	385,4	385,4	386,4

Figure 25: OMVG and coal scenario transmission build

2.9. FORCED TRANSMISSION

Many of the scenarios explored above chose to build large quantities of 33kV lines, as they are cheaper than the 132kV alternative.[1] However, in reality, this is unlikely to be a technically feasible option. Long 33kV lines would have high losses, and therefore 132kV lines would be more technically desirable if power is being transmitted further.

We therefore ran another scenario where we pre-planned into the model a 132kV "backbone" of transmission investment along the length of the country, as shown in Figure 26.

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[1] The model was offered all line options in the initial model runs, but of course not all line options are technically feasible even when they are economically feasible. For this reason we restrict the options of transmission line build in this scenario.

Figure 26: Transmission scenario transmission build
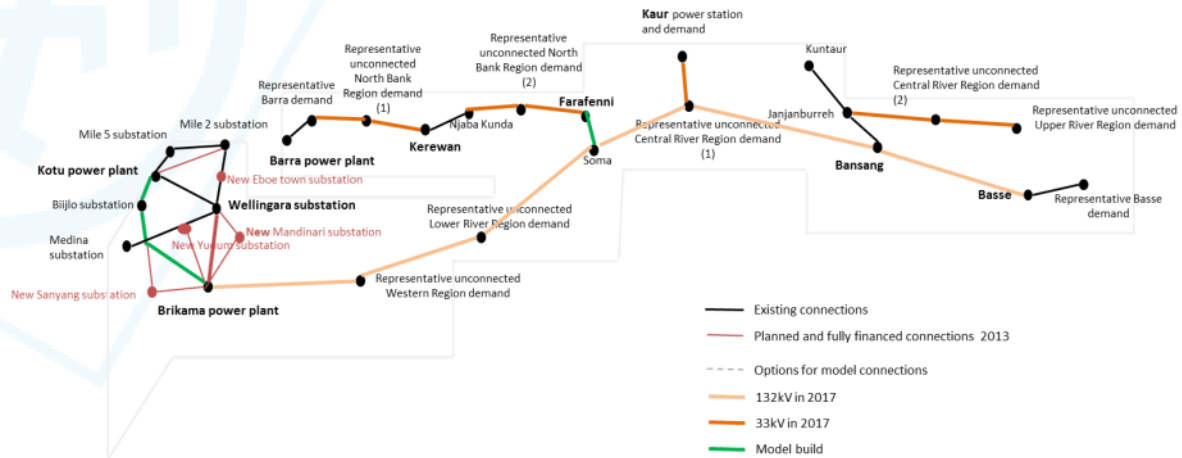
The results are shown in Figure 27 and Figure 28. In this scenario the model chose to build very large amounts of coal generation, as it was able to transport it to the rest of the country. This is an interesting result. It would not be practical in the Gambia alone, because of the high reliance on a single source. However, it might be an interesting choice if an interconnection with Senegal was also built.

Figure 27: Transmission scenario generation new build (MW)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LFO new	0.00	0.00	0.00	0.00	25.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00
HFO new	0.00	0.00	9.00	17.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	125.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	0.00	0.00	0.00	0.00	0.00
SolarPV	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	1.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 28: Forced transmission scenario generation (MWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SolarPV	-	-	-	-	161.7	161.7	162.1	161.7	161.7	161.7	162.1	161.7	161.7	161.7	162.1	161.7	161.7	161.7	162.1	161.7	161.7	161.7	162.1
Wind	-	-	-	98.55	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	990.9	892.4	894.8
Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HFO new	-	-	12,72	45,11	69,88	98,93	105,9	648.3	2,035	3,035	3,087	3,087	11,29	37,55	49,76	94,45	116,9	3,087	3,087	5,284	11,50	9,937	37,64
HFO existing	208,3	217,8	210,4	210,4	211,9	219,9	253,7	2,906	3,681	4,964	5,068	5,068	3,168	21,44	58,63	74,62	101,7	1,900	633.6	633.6	-	-	-
LFO new	-	-	-	-	23,84	55,95	82,55	-	-	-	1,511	2,701	4,183	4,183	4,183	4,183	4,183	4,183	4,183	4,183	4,183	4,183	23,71
LFO existing	6,023	6,192	6,385	8,208	8,507	8,561	8,331	84.82	84.82	84.82	235.7	235.7	1,821	3,371	8,331	8,308	8,308	-	-	-	-	-	-
OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 70MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	445,7	394,2	453,3	489,4	521,2	522,6
Coal 125MW CFB	-	-	-	-	-	-	-	627,3	694,4	766,4	845,7	892,5	930,7	930,7	933,3	930,7	930,7	782,2	891,4	882,8	898,7	930,7	933,3
Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

The costs and other key outputs of each of the scenarios are compared in Table 1 and Table 2 in Section 3.

3. COMPARING THE INITIAL SCENARIOS

The table below compares the scenarios.

Table 1: Comparison of scenarios

Scenario		1	2	3	4	5	6	7	8	9
Total over period 2010-2032	Units	Baseline (with coal)	Baseline (no coal)	High fuel cost	High VOLL (no coal)	Renewable target	Off-grid FIT	OMVG (no coal)	OMVG (with coal)	Forced network (with coal)
Demand (expressed)	GWh	16,816	16,816	16,816	16,816	16,816	16,816	16,816	16,816	16,816
Generation	GWh	17,734	17,413	17,548	17,509	17,268	17,369	17,837	18,343	19,508
Renewable generation	GWh	240	242	1,622	96	1,143	943	5,230	4,931	22
Renewable generation	% demand	1.4%	1.4%	9.6%	0.6%	6.8%	5.6%	31.1%	29.3%	0.1%
Unsupplied energy (of expressed)	GWh	207	222	225	130	226	206	215	183	143
Unsupplied energy (of expressed)	%	1.2%	1.3%	1.3%	0.8%	1.3%	1.2%	1.3%	1.1%	0.9%
Generation investment	US$m (2011 real)	525	384	512	454	635	482	340	606	729
Transmission investment	US$m (2011 real)	33	140	43	127	90	67	225	134	189
Fixed operational costs (ex. Interest)	US$m (2011 real)	74	86	100	88	127	124	91	86	113
Variable operational costs (inc. fuel)	US$m (2011 real)	1,724	2,169	2,645	2,204	2,105	1,943	1,616	1,084	1,169
Capital recovery (capital and interest)	US$m (2011 real)	782	537	603	639	757	658	607	890	1,370
Emissions	ktCO2	12,231	10,217	9,476	10,361	9,594	9,773	7,502	10,013	15,835
Overall modelled cost (objective function)	Present value US$	857	915	1,054	970	960*	891*	794	711	829

* does not include full cost of renewable plant because of the way the modelling represents the feed-in-tariff.

Table 2: Percentage comparisons

Total over period 2010-2032	Compare 2 with 1 (baseline no coal and with coal)	Compare 3 with 2 (high fuel cost and baseline)	Compare 4 with 2 (high VOLL and baseline)	Compare 5 with 2 (renewable target and baseline)	Compare 6 with 2 (offgrid FIT and baseline	Compare 7 with 2 (OMVG and baseline)	Compare 8 with 7 (OMVG with and without coal)	Compare 9 with 1 (forced network and baseline)
Generation	-1.8%	0.8%	0.6%	-0.8%	-0.3%	2.4%	2.8%	10.0%
Renewable generation	0.9%	569.8%	-60.5%	372.2%	289.7%	2060.2%	-5.7%	-90.9%
Unsupplied energy (of expressed)	7.4%	1.3%	-41.7%	1.4%	-7.4%	-3.1%	-15.3%	-30.7%
Generation investment	-26.8%	33.2%	18.0%	65.3%	25.3%	-11.6%	78.2%	38.9%
Transmission investment	318.7%	-69.2%	-9.3%	-35.4%	-51.9%	61.2%	-40.8%	465.7%
Fixed operational costs (ex. Interest)	15.9%	15.8%	2.5%	47.6%	43.9%	5.3%	-5.4%	51.2%
Variable operational costs (inc. fuel)	25.8%	21.9%	1.6%	-3.0%	-10.4%	-25.5%	-32.9%	-32.2%
Capital recovery (capital and interest)	-31.3%	12.3%	18.9%	40.9%	22.5%	13.0%	46.7%	75.1%
Emissions	-16.5%	-7.2%	1.4%	-6.1%	-4.3%	-26.6%	33.5%	29.5%
Model objective function	6.8%	15.1%	6.0%	N/A*	N/A*	-13.2%	-10.5%	-3.3%

does not include full cost of renewable plant because of the way the modelling represents the feed-in-tariff.

Tables of the annual figures for each scenario are provided in Annex 4.

4. FEEDBACK FROM STAKEHOLDER WORKSHOP

These scenarios and associated recommendations were discussed at the stakeholder workshop on 5 July on the subject of developing the electricity strategy.

The stakeholder comments show a good level of engagement in the electricity strategy development. Some controversy and active debate are very healthy in the electricity sector and it is positive that stakeholders are challenging the findings.

Some comments that were received are discussed below.

- **Concern about the continued use of fossil fuel**

  Several stakeholders raised concern about the environmental impacts of using fossil fuel, and that if Africa should develop on the same path as developed countries. One participant asked what would happen if you assumed that all fossil fuel on the earth was depleted.

  Currently, fossil fuels and large scale hydro provide the least cost and most reliable ways for running an electricity system. Those countries with greater than 50% renewable penetrations (such as Brazil and Norway) have excellent hydro resources. Reasonably high penetrations of more variable renewables (wind and solar) have been achieved, but these need very flexible and reliable conventional plant for back-up. For example, Denmark uses strong interconnections to get the balancing power from neighbouring countries to manage variable wind generation (around 30%).

  Apart from the proposed regional OMVG hydro project the Gambia has little, if any, hydro development potential. Therefore, it seems likely that at least some fossil fuel generation will be required to create the reliable power system that is needed for economic development.

  Reliability and stability in a power system are achieved through careful management of generation and demand. Abnormal frequency events can be caused by demand and generation drifting out of balance over time, or by sudden shocks to the system following the loss of significant generation or demand due to a plant or network fault. As discussed in Annex 2, the fuel oil engine generation plants used by NAWEC at present have a low inertia value (a poor ability to help the system respond to a frequency change). This causes the system to be more unstable when compared to a system with high inertial rotary machines such as steam turbines (which help the system manage a frequency change). The fact that NAWEC are managing a system with only engines at present may be one of the reasons for frequent frequency disturbances experienced in the Gambia. The future addition of variable renewable generation capacity may lead to significant additional stability problems in the grid if proper action is not taken. Therefore, the adding steam turbine based technology in the Gambia can be crucial to maintain system adequacy. Fossil fuel powered steam turbines are therefore critical if the Gambia is to increase its renewable penetration.

  Estimates of reserves of fossil fuels vary on whether proven reserves or unproven (and potentially more difficult to access) reserves are considered. It also depends on assumptions about future use. For example, oil reserves have been estimated as having 40 years of production, gas at 60-100+ years and coal at 100-400 years.

  The environmental impacts of using fossil fuels, and in particular climate change impacts, have been well documented. Some of the lower cost of fossil fuels compared to renewable alternatives is because of these external environmental costs.

  However, the Gambia has an urgent need to develop its economy, and access to electricity is an important enabling step in that process. Without more hydro resources, fossil fuels are currently the least cost and most reliable way to achieve higher electricity generation. Developed countries are still using high proportions of fossil fuel in their electricity mix. For example, in 2011 Germany still generated about 48% of the electricity it needed from coal and 14% from gas, with 20% from renewables, while the UK used 29% from coal, 40% from natural gas and 9.2% from renewables.

  Ultimately, the decision on whether or not to permit fossil fuel is properly a matter for the Gambian Government. They should consider carefully the economic and environmental benefits of various paths.

  One of the simplest and least cost routes for the Gambia to minimise the use of fossil fuels and cost at the same time is if the OMVG project goes ahead.

- **Concern about the potential use of coal**

  Several stakeholders raised concern about the environmental impacts of coal (both the emissions from the power plant itself and the impact of mining). Stakeholders highlighted that some developed countries are considering restrictions on new build of coal power plants. Also,

there were concerns that international finance institutions would not be prepared to support coal power plant build.

The important drawback for coal is the carbon intensity and environmental impact. CO_2 emissions are higher than oil-fired generation at around 0.85 tCO_2/ MWh, compared to 0.595 tCO_2/ MWh. As a result of concerns about environmental impact, international finance institutions have become increasingly cautious about lending to coal-fired projects, unless they are cleaner than alternatives (for example, rehabilitating old coal plants in India to bring them up to modern environmental and efficiency standards).

Coal is used in many developing countries to help increase access to electricity, for example 92% of electricity generation in South Africa is from coal and 69% in India (IEA 2010). Two examples of planned coal projects in Africa are:

- **South Africa** was facing a crisis of generation, and the power utility Eskom was struggling to finance generation needs. In April 2010, the World Bank granted the country around a $3 billion loan for Medupi supercritical coal plant (4,800 MW), due to start generation in 2313, with additional loans for renewable and energy efficiency projects. The President of the World Bank stated that, "Coal is still the least-cost, most viable, and technically feasible option for meeting the base load power needs required by Africa's largest economy". The loan from the World Bank has been highly controversial, with opposition from some local groups within South Africa and global NGOs.
- The National Electricity Board of **Senegal** (SENELEC) has commissioned the construction of a 125 MW coal power plant to help meet the growing electricity demand in Senegal. This will require an investment of CFAF 118 billion, through a "Build, Own, Operate (BOO)" arrangement. The power plant will be located near Bargny Minam village, 32 km from the city of Dakar, on a total land area of 29 hectares. The main funders of the project are the ADB Group, ADB and BOAD. The project was subject to an environmental and social impact assessment, which was reviewed as part of the due diligence process, mandated by the donors. The project has been designed to comply with the relevant environmental and social requirements of the World Bank and will apply the standards set by the World Bank for atmospheric emissions (Sendou 2009).

The IEA World Energy Outlook 2011 highlighted that coal will continue to play an important role in increasing access to electricity, stating that "more than half of the … increase in on-grid electricity generation capacity is expected to be coal-fired."

While some developed countries are looking at the potential for abating coal, they are already very high users of coal. 49% of generation in the USA is from coal, 46% in Germany (IEA 2010). Coal currently produces around 40% of global power requirements. The American Coalition for Clean Coal Electricity (ACCCE) has carried out analysis to show that, generally, states that have the highest penetration of coal have the lowest electricity rates.

According to the World Coal Association, coal is the most widely geographically distributed fossil fuel energy resource, and it has been estimated that there are over 860 billion tonnes of proven coal reserves worldwide, sufficient to last over a hundred years at current rates of consumption. Reserve estimates vary and should always be treated with caution. They depend on economic drivers and significant unproven potential coal resources mean that some analysts believe that coal could last considerably longer.

According to the IEA Clean Coal Centre, there are over 2,300 coal-fired power stations worldwide (7,000 individual units). Approximately 620 of these power stations are in China. Within this global context, any small coal generating unit of the scale possible in the Gambia (say, 70MW) would be very small, and the Gambia is currently more likely to be impacted by the climate change caused by developed countries than to be a major contributor to climate change.

Coal does appear to be a viable economic option in our analysis, and offers an option for diversification away from oil-fired stations. To validate this conclusion, there would need to be a full technical feasibility study, including the cost for appropriate port facilities. We would also recommend a full environmental and social impact assessment.

Ultimately, the decision on whether to permit coal is properly a matter for the Gambian Government, working with NAWEC and the NEA. A technical and environmental study could help them to reach that decision.

- **Interest in different renewable technologies**

Stakeholders highlighted the potential of different technologies. In particular, wave and tidal, small hydro and concentrating solar power (CSP) and biogas, as well as the use of batteries to balance solar PV were mentioned.

Hydropower is location dependent. Small hydro power works by using falling water to drive a turbine, which generates electricity. This process converts potential energy stored in water held at height to kinetic energy which is used to turn the turbine and produce electricity. The amount of energy that a small hydro power installation can generate depends on the flow rate of the water (how much water is flowing past each second) and the head (which is the amount of vertical drop in the water flow).

There are no identified opportunities for either large or small scale hydro in the Gambia itself, which is a flat country with no 'head' of water.

The best sites for any kind of hydro generation are those which have both a high flow rate and a high head. It is sometimes possible to build a hydro installation where only one of these values is high, but this is unlikely to deliver the full potential of the installation or be as economically viable. Some head is required even for small and run of river schemes. An example of a high head scheme would be a waterfall where the water intake can be close to the turbine. Low head schemes can run over much larger distances, such as a 'run of the river' hydro system where there is a more gradual drop in height over a large distance. It is also important to note that small scale and 'run of river' hydro have greater instability of water flows than large hydro, so the capacity can be thought of as less 'firm' and reliable.

Overall, without any indication of hydro potential in the Gambia or portfolio of potential projects to consider, it is impossible to consider the option of hydro within this study.

In our opinion, the other technologies are not suitable due to their current state of development:

- **Battery storage** has relatively high efficiency, as high as 90% if they are operated carefully. However, they have a short design life, particularly in a hot climate like the Gambia, for example 36 months for lithium ion polymer batteries. They are also still expensive and have high maintenance costs. They are therefore not recommended.
- **Concentrated solar power systems** are still beginning commercial take off. After the first early projects in the United States in the 80's and early 90's, development was slow until the beginning of a new expansion phase in the 2000's. Since then, commercial development has been most significant in Spain. In 2010, the global installed capacity was 1,061 MW. The generation price of CSP is still uncertain and the commercial maturity of the different technologies is uneven. It is difficult to envisage any solar thermal power generation plant as a near term electricity supply option for the Gambia. The first reason is the relatively small power capacity requirements in the country. At the present technology state of the art, the technical and economic viability of such CSP power plants are in the same or over the total installed capacity in the whole country. Becoming reliant on a technically early stage technology for a very significant proportion of the power requirements of the country would be highly undesirable. Such technologies would be expected to have significant downtime, and additional capacity would be needed to cover the demand in these periods. Furthermore, the relatively high cost of the technology at present is not likely to make it part of a least cost development plan. Solar thermal power could be an interesting long term option once the technology is more robustly commercially demonstrated so the costs and expected generation is clearer, has moved further along the learning curve to make it more affordable, and once the Gambia is part of a more robust interconnected power pool with adequate reserve capacity and power stability.
- The most established form of tidal power generation is through a **tidal barrage**. This is a massive engineering project, and involves building a barrage across a bay or river that is subject to tidal flow. The viability of tidal barrage schemes is highly location dependent. The available power varies with the square of the tidal range, so barrage is best placed in a location with very high-amplitude tides. Tidal barrage is therefore not likely to be a possibility in the Gambia. The available power for a tidal barrage varies with the square of the tidal range (the difference between high and low tides), so a barrage is best placed in a location with very high-amplitude tides. The tidal range in the Gambia is relatively small (at Banjul the range is 1.6 m in spring tides and 0.7 m in neap tides). By contrast, the tidal range at La Rance tidal barrage in France averages 8 metres and reaches up to 13.5 metres.
- At present, **wave and tidal stream technologies** are at very early stages of demonstration and their costs and achieved capacity factor have not been demonstrated. Both types of generators require the engineering of complex moving equipment in a wet, salty and extremely robust environment (strong currents or waves). This is a very big technical challenge, and it is not yet clear how successful

these devices will ultimately be. Also, because of their early stage of development, the costs are currently very high (essentially each new project is "first of a kind"). At the present time there are no fully commercial **tidal stream** devices, although some near commercial scale prototypes are being tested. Tidal stream generators require very fast tidal currents, such as those found between islands. Tidal currents along most of the coast are weak (< 0.1 m/s) except for the Gambia estuary, where tidal filling and emptying causes tidal currents to be over 1 m/s. However, it is not yet clear whether such currents will be sufficient for the economic use of tidal stream generators. For example, the tidal test site at the European Marine Energy Centre (EMEC) on Orkney in Scotland offers high velocity marine currents, which reach almost 4 m/s at spring tides. **Wave** generation is probably at an even earlier stage of development than tidal stream, although again some prototypes are under development. There is less harmonisation in the type of design being tested, with a wide range of possible prototypes at very different stages on the development pathway.

More details on all candidate technologies are given in Annex 2.

- **Carbon pricing**

Another subject raised by stakeholders was the environmental value of renewable technologies, because they do not emit carbon dioxide.

At present, the Gambia does not have a price for carbon, so this was not included in the model.

- **Comparison by technology by long run marginal cost**

Several participants expressed an interest to see the costs of technologies more clearly.

Figure 29 shows the long run marginal costs of generation technologies for a range of capacity factors.

Long run marginal costs means that the cost of the initial capital cost is spread over the lifetime of the investment. The cost per kWh includes a spread out cost for the capital, operational and fuel costs.

The capacity factor makes a big difference to projects. If a project has a high capacity factor, it will spread the capital cost over a large number of generating hours, so the impact of the capital cost on the long run marginal cost of each kWh of electricity generated will be lower. If it has a low capacity factor, it will spread the capital cost over a smaller number of generating hours, so the impact of the capital cost on the long run marginal cost of each kWh will be higher.

Figure 29: Long run marginal costs of different generation technologies
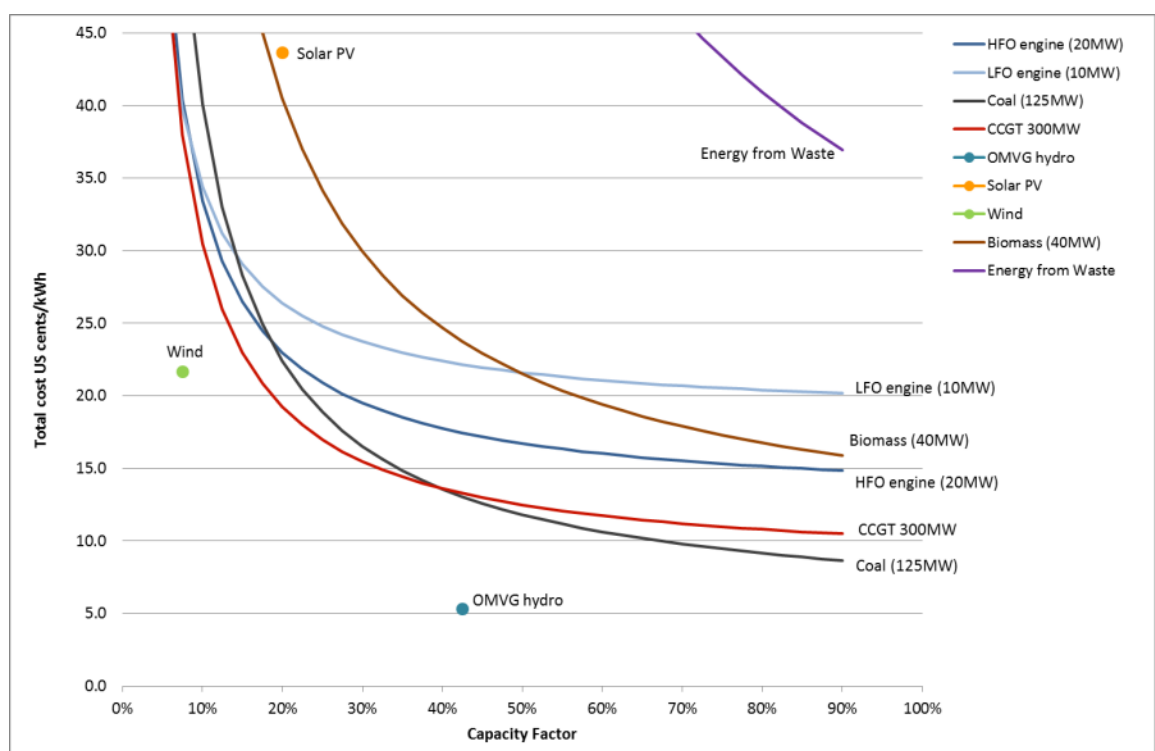
Renewable projects like solar PV, wind and hydro have no control over their capacity factor (except downwards). They can only generate based on the resource available. For this reason, they show as a single point on the chart.

The OMVG hydro project offers the lowest cost option. From the chart, it is possible to see that coal is able to achieve the next lowest cost when it generates at high capacity factors. The cost drops below 10 cents/kWh at over 70% capacity factor. The next lowest cost is gas (CCGT), then HFO, then biomass. Wind and LFO are available at similar costs per kWh, and finally energy from waste and solar PV cost significantly more per kWh than the other technologies.

- **Desire to see more ambitious renewable energy targets**

Some stakeholders who represent renewable interests wanted to see a more ambitious program. A target of up to 80% renewable electricity was mentioned and the opportunity to be world leaders in renewable electricity.

At present, most renewable electricity generation costs more than conventional generation. It will be up to the Gambian government to decide what costs can be met by consumers. Any money borrowed to build projects will ultimately need to be repaid in either the bills paid by consumers or by taxpayers in the Gambia (unless the money is a straightforward grant from a donor agency).

To illustrate a more ambitious scenario, in the next section we consider a scenario where renewable electricity meets over 50% of the Gambia's needs (partly through hydro and partly wind and solar PV).

- **Need to consider other demand scenarios**

There was concern that there might be barriers to full access to electricity that were not reflected in our modelling. For example, the connection charge for domestic customers is typically 6,000 GMD. This is a low charge in an international context, but is very significant compared to salaries in the Gambia. This acts as a barrier to customers wishing to connect. Furthermore, customers on prepayment meters voluntarily disconnect themselves for periods when they find electricity difficult to afford. So, for example, they will continue to top up by the same amount each week when the price rises, and when the power runs out they will stop using it.

It is worth emphasising that forecasting demand is difficult for the Gambia. The precise size and number of households in the population will not be known until the 2013 census is completed. The link between demand growth and GDP is not a precise correlation, although there is some link. There is also no real certainty on what the demand of current customers would be if it was not supressed by frequent load shedding. Therefore, the forecasts used in this study should be treated as estimates only.

In our scenarios so far, we have considered demand reaching 950 GWh by 2025 (which is lower than the WAPP base scenario of 1,017 GWh), and by 2030 it reaches 1,184 GWh.

In the next section we will consider a slower demand growth, which is lower than the lowest WAPP scenario. In this scenario, demand reaches 510 GWh by 2025 (significantly lower than the WAPP low scenario of 806 GWh), and by 2030 it reaches 760 GWh.

The new scenario (section III 1) with this lower demand forecast is also useful to illustrate how realistic policy objectives are and the cost of optimistic targets for electrification.

The role of microgrids and small provincial systems in "revealing" potential demand can be very important. Until regional interconnection can be achieved, these small systems should be encouraged as a first step to full electrification.

- **Highlighting the role of energy efficiency**

There was a concern that the report did not give sufficient emphasis to energy efficiency. We recognise this point and have added it to the proposed action plan in Section IV 4.

- **Desire for more clarity on what our recommendations for NAWEC might mean**

It was felt that some of the recommendations for NAWEC in the presentation were not clear. These have been clarified.

- **Emphasising the importance of governance**

Stakeholders chose to emphasis and echo our comments on governance issues. International financial institutions and donor funding will not choose to finance the electricity sector unless governance is seen to be very good and transparent. There were suggestions that the 2002

Act which established PURA may need to be revised, or followed more precisely on the division of responsibilities. There were also some suggestions that NAWEC's monopolistic situation could be reviewed.

As a result of these discussions, we present three options for future development in the Gambia in the next section. These present clearer visions of options going forward.

At the request of stakeholders and the Ministry of Energy, we also added a table of acronyms (at the front of this document) and a more accessible shorter summary document (sent with this document).

The list of attendees and schedule of the workshop are given in Annex 5.

III THREE POTENTIAL INVESTMENT PLANS

As a result of the discussion with stakeholders, in this section we outline three possible visions for electricity sector development in the Gambia:

Scenario one, continuing on the present path: represents a current (low ambition) path. When the WAPP is implemented, the Gambia is a relatively passive participant, only accepting power and without the resources to set the direction and drive development. The reliability of the power network in the Gambia remains poor (due to the continued reliance on engines) and demand is relatively suppressed.

Scenario two, enabling greater cross border trade, renewable generation and reliability: represents a higher ambition path, where the Gambia can play a role in the WAPP and take advantage of WAPP by having more reliable and lower marginal cost power to export.

Scenario three, high renewable energy ambitions: represents an even more ambitious path, where the Gambia can become a leader in renewables by having high levels of renewable import from the regional OMVG hydro scheme and higher renewable energy targets within the country as well.

These do not represent all possible outcomes for the sector, but they do help to compare some possible future developments. A wider range of scenarios and the detailed assumptions used in the modelling are given in the associated evidence report.

It should be remembered that these scenarios only provide comparisons of future paths to help aid policy decisions. They are not predictions of the future.

1. CONTINUING ON PRESENT PATH

1.1. DESCRIPTION OF SCENARIO

Continuing on the present path represents a relatively low ambition scenario for the Gambia. In this scenario, we assume that the transmission system is reinforced very gradually. 132kV lines connect some provincial systems in 2020, linking Barra through Kerewan to Farafenni and Kuar in 2020, and in 2025 linking Bansang and Basse. Eventually regional interconnection arrives in 2030, including a 225kV link from Soma to Brikama. This is illustrated in Figure 30.

Power demand grows slowly in this scenario. By 2025, it reaches 510 GWh (significantly lower than the WAPP low scenario of 806 GWh), and by 2030 it reaches 760 GWh. This represents year-on-year growth of 6-8%, which is much slower than growth in recent years where demand has grown by 18% year-on-year in many years (more than doubling from 80 GWh in 2004 to 184 GWh in 2010).

Demand is primarily met by oil engines (HF*O* and LFO). This means that the system is likely to remain relatively unstable. The generation is shown in Figure 31.

There is no renewable electricity target in this scenario. Some wind and solar PV is built, particularly in isolated systems where it can help meet small increments of demand. However, the proportion of renewable generation remains low, reaching about 2% of demand.

Figure 30: Electricity transmission built in scenario one (current path)

Figure 31: Electricity generation in scenario one (current path)

Generation MWh

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SolarPV	-	-	-	-	147.0	325.3	1,003	1,185	1,384	1,601	1,841	2,090	2,366	2,663	2,992	3,331	3,704	4,378	4,451	4,545	4,659	4,782	4,928
Wind	-	-	-	98.55	990.9	990.9	993.6	990.9	990.9	990.9	993.6	990.9	7,371	7,371	7,391	7,371	7,371	7,371	7,391	7,371	7,371	7,273	7,292
Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HFO new	-	-	24,35	44,81	37,49	42,52	58,59	71,87	89,53	96,09	82,26	117,7	187,8	313,2	306,8	312,5	405,3	463,3	597,1	627,8	755,6	806,7	902,0
HFO existing	208,3	217,8	198,8	192,7	209,2	216,1	212,2	210,6	204,5	210,8	249,6	235,5	192,7	74,95	105,3	123,3	134,7	115,6	22,96	36,30	-	-	-
LFO new	-	-	-	-	-	-	-	3,690	5,234	6,903	8,853	26,80	34,61	43,03	52,26	61,33	13,67	30,98	39,30	48,08	22,96	33,62	13,98
LFO existing	6,023	6,192	6,385	3,099	4,437	5,930	8,230	8,208	8,208	8,208	6,361	6,344	6,811	11,92	14,37	14,34	9,816	-	-	-	-	-	-
OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 70MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 125MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 32: New generation capacity built in scenario one (current path)

Generation investment MW per year

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LFO new	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.00	0.00	0.00	0.00	10.00	0.00	0.00	0.00	0.00	5.00	5.00	0.00	0.00	0.00	0.00	0.00
HFO new	0.00	0.00	9.00	17.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.77	0.00	0.00	20.00	0.00	20.00	0.00	20.00	0.00	20.00
Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SolarPV	0.00	0.00	0.00	0.00	0.09	0.10	0.38	0.11	0.11	0.12	0.13	0.15	0.16	0.17	0.18	0.20	0.21	0.38	0.03	0.06	0.07	0.07	0.08
Wind	0.00	0.00	0.00	0.00	1.36	0.00	0.00	0.00	0.00	0.00	0.00	9.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

1.2. COSTS, BENEFITS, RISKS AND BARRIERS

Capital costs are not particularly high in this scenario. However, variable operating costs are very significant. This means if oil prices were to increase significantly from the forecast, the cost to consumers would be affected.

As demand is increasing relatively slowly, unsupplied demand is relatively low (generation growth can keep pace with demand). CO_2 emissions per unit of demand are relatively high at $600 tCO_2/GWh$

Table 3: Key cost indicators for scenario one (current path)

	Units	2011-2015	2016-2020	2021-2025	2026-2030
Demand (expressed)	GWh/year	235	309	441	655
Renewable generation	% demand	0%	1%	2%	2%
Unsupplied energy (of expressed)	%	0%	1%	1%	1%
Fixed operational costs (ex. interest)	US$m (2011 real)/yr	2	2	3	4
Variable operational costs (inc. fuel)	US$m (2011 real)/yr	34	40	57	79
Capital recovery (capital and interest)	US$m (2011 real)/yr	3	8	17	30
Emissions	ktCO$_2$/year	144	184	267	396

The low demand scenario might represent a situation where the electricity supply remains unreliable and subject to load shedding, and where consumers are not able to connect quickly even when there is supply in their region, because of the high costs of connection relative to income. In this scenario, many Gambians will not have reliable access to electricity by 2030. This will limit economic and social development.

The benefit of this scenario is that it requires relatively little investment commitment. The downside is that it is highly sensitive to the oil price, and in the event that prices rise against forecast there would be a significant increase in power prices to consumers.

The generation mix would remain based on oil engines, which are not good for grid stability. It also shows the risks of delaying regional integration, which will mean the system is isolated, less easy to balance and has fewer generation options because only small plant are possible (it would be risky to rely on a single large plant in such a small system). Therefore, consumers would continue to suffer from unreliable supplies.

The oil-fired generation has high carbon intensity, and CO_2 emissions are only significantly lower than other scenarios because less demand is met.

Once the delayed WAPP connection is in place, the Gambia will be part of a larger and more stable system. The oil-fired generation has high marginal costs, so is unlikely to be very competitive on a regional basis. It is likely that the Gambia might become a net importer, assuming their neighbours introduce lower cost generation options. Trade may allow lower cost and more stable supply, but has the potential risk associated with relying on power plants in other countries.

A potential barrier to achieving even this scenario is finance. It could not be achieved if private investors lacked the confidence to invest in generation in the Gambia, and if NAWEC was not able to raise the capital to build power plants.

2. ENABLING TRADE, RENEWABLES AND RELIABILITY

2.1. DESCRIPTION OF SCENARIO

In this scenario, the country is fully interconnected and has a single transmission system by 2025. 132kV lines connect some provincial systems in 2020, linking Barra through Kerewan to Farafenni in 2020. Regional interconnection arrives in 2025, including a 225 kV link from Soma to Brikama, and at the same time more 132 kV is built linking Soma, Kuar, Bansang and Basse to the new regional system. This is illustrated in Figure 33.

Power demand grows more rapidly in this scenario. By 2025, it reaches 950 GWh (still lower than the WAPP base scenario of 1,017 GWh), and by 2030 it reaches 1,184 GWh. This represents year-on-year growth of up to 20% in the early part of the simulation, in line with rapid demand growth observed in recent years.

Figure 33: Electricity transmission built in scenario two (reliability)
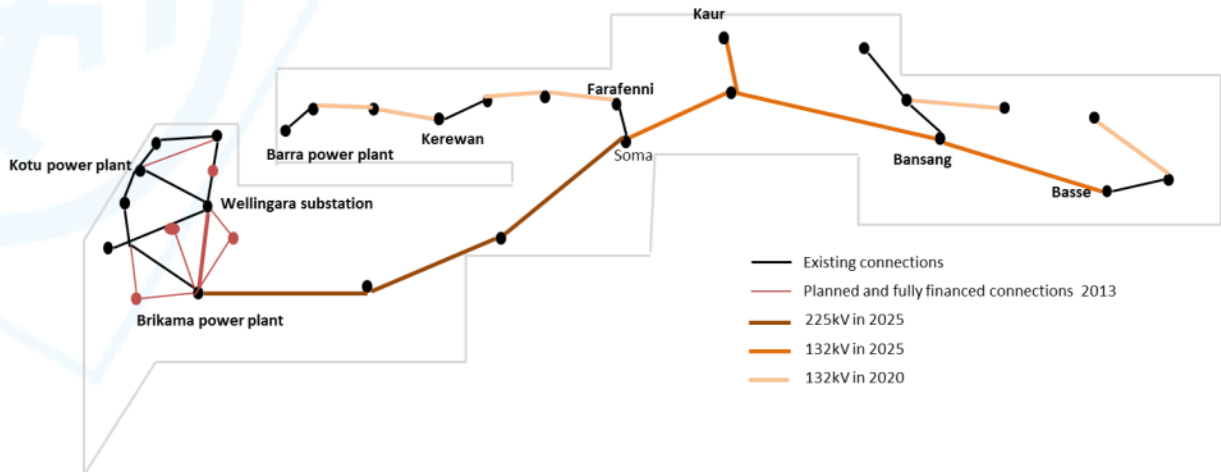
In this scenario demand is met primarily by oil-fired generation until 2025 (see Figure 34). Then, with WAPP, a coal fired steam turbine is introduced. This cannot be introduced until the markets are connected, because it would be a very large power plant for the Gambian system and if it were unavailable.

There is a renewable electricity target in this scenario. Until 2025, the target is capped at 5% to represent a concern about high renewable integration until cross border trade and the introduction of coal power plant allow more reliable integration. The target then increases to 10% by 2030.

Figure 34: Electricity generation in scenario two (reliability)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SolarPV	-	-	-	-	4,186	6,519	9,212	12,35	14,49	16,98	19,82	22,34	23,24	24,25	25,61	27,68	31,18	44,40	57,09	70,47	85,06	89,89	95,65
Wind	-	-	-	98.55	990.9	990.9	1,516	3,587	5,757	8,149	10,81	13,67	16,84	20,31	24,17	28,25	28,25	33,84	33,93	33,84	33,84	33,74	33,83
Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HFO new	-	-	20,85	52,48	71,52	104,0	149,3	168,3	222,9	217,1	244,6	238,8	395,3	405,2	420,2	349,4	372,9	427,5	466,4	503,4	606,4	657,6	712,4
HFO existing	208,3	217,8	202,3	203,1	225,4	236,7	242,3	277,2	250,9	282,8	281,7	305,5	166,6	177,5	185,8	56,14	77,11	41,02	38,64	38,54	-	-	-
LFO new	-	-	-	-	8,910	28,62	46,91	74,85	102,2	125,2	169,2	186,7	205,8	226,2	249,0	33,17	32,95	34,25	33,97	33,55	5,672	5,672	5,672
LFO existing	6,023	6,192	6,385	8,208	6,536	6,536	6,303	6,337	6,337	9,228	12,43	12,40	12,40	12,40	12,43	6,370	6,370	-	-	-	-	-	-
OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 70MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	521,2	521,2	521,2	522,6	521,2	521,2	521,2	522,6
Coal 125MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 35: New generation capacity built in scenario two (reliability)

Generation investment MW per year

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
■ Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
□ OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ LFO new	0.00	0.00	0.00	0.00	10.00	12.23	5.00	5.23	5.00	0.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ HFO new	0.00	0.00	9.00	17.80	20.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00	0.00	0.00	0.00	0.00	0.00	20.00	0.00	0.00	20.00	0.00	0.00
■ Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
□ Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ SolarPV	0.00	0.00	0.00	0.00	2.39	1.33	1.52	1.81	1.23	1.42	1.59	1.47	0.51	0.57	0.74	1.22	2.00	7.55	7.15	7.72	8.33	2.76	3.14
■ Wind	0.00	0.00	0.00	0.00	1.36	0.00	0.79	3.16	3.30	3.64	4.01	4.40	4.83	5.28	5.77	6.30	0.00	8.51	0.00	0.00	0.00	0.00	0.00

2.2. COSTS, BENEFITS, RISKS AND BARRIERS

The total costs are higher than the first scenario, as more demand needs to be met. Capital costs are higher in this scenario. However, variable operating costs are comparatively lower. This means if oil prices were to increase significantly from the forecast, the cost to consumers would be less affected than in the first scenario.

Table 4: Key cost indicators for scenario two (reliability)

	Units	2011-2015	2016-2020	2021-2025	2026-2030
Demand (expressed)	GWh/year	284	592	851	1,087
Renewable generation	% demand	1%	3%	5%	8%
Unsupplied energy (of expressed)	%	4%	4%	4%	4%
Fixed operational costs (ex. Interest)	US$m (2011 real)/yr	2	3	5	9
Variable operational costs (inc. fuel)	US$m (2011 real)/yr	40	81	104	89
Capital recovery (capital and interest)	US$m (2011 real)/yr	6	21	42	94
Emissions	ktCO2	167	345	524	767

CO_2 emissions per unit of demand towards the latter part of the simulation are higher than the first scenario at $700 tCO_2/GWh$, but this is not a very significant increase as both oil and coal generation have relatively high CO_2 emissions. The average cost per unit of demand is also comparable to the first scenario.

By using oil and coal generation, as well as some contribution from renewables, this scenario reduces exposure to oil prices and increases diversification. The exposure to oil prices is not completely eliminated, but is significantly reduced. The scenario does add a new exposure to coal prices, although historically these have been less volatile than oil.

The finance required in this scenario is greater than scenario one because more demand is met (requiring more generation plants and transmission lines) and because both coal and renewable generation is more capital intensive than oil. This means a strong commercial and governance framework will be important to allow investors to be confident in the sector.

The coal plant would be a steam turbine, which allows the grid to be more stable and reliable (due to increased inertia on the system). Greater stability and controllability of the system in turn allows greater integration of renewable sources.

Rather than being a passive receiver of power in the regional pool, in this scenario the Gambia has the opportunity to become an active seller of power. It would be possible to choose a larger coal power plant, and sell over the borders into the pool, or even more directly into areas of Senegal that might be more practically supplied from the Gambia than from Dakar. A larger power plant would have greater economies of scale.

Barriers to achieving this scenario include investor confidence, delays in regional integration and a risk of decreased demand if consumers have an economic barrier to connect and use electricity (cost of connection and power prices). Lower demand would reduce the economic incentive to build a power plant.

3. HIGH RENEWABLES AMBITIONS

3.1. DESCRIPTION OF SCENARIO

The third scenario considers a scenario that aims for more ambitious renewable deployment.

There is a higher renewable electricity target. Until 2020, the target for wind and solar PV is capped at 10% to represent a concern about high renewable integration until cross border trade and the introduction of coal power plant allow more reliable integration. The target then increases to 20% by 2030. Along with the regional hydropower, over 50% of demand is met by renewable electricity by 2030.

Figure 36: Electricity transmission built in scenario three (renewable ambitions)
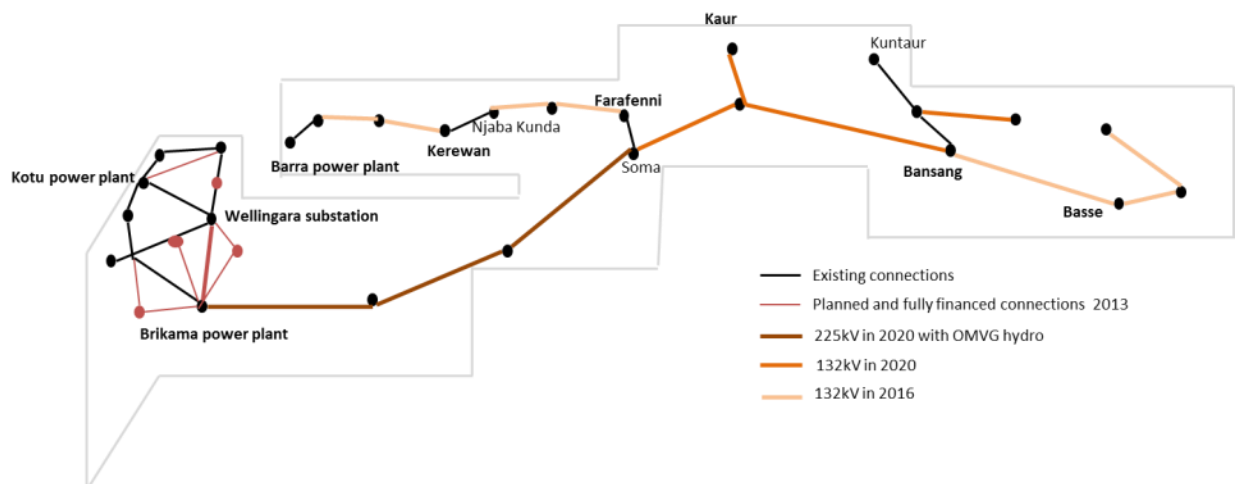
Demand is as scenario two. The country is fully interconnected and has a single transmission system by 2020. 132kV lines connect some provincial systems in 2016, linking Barra through Kerewan to Farafenni and Bansang to Basse. Regional interconnection arrives in 2025, including a 225 kV link from Soma to Brikama, and at the same time more 132 kV is built linking Soma, Kuar, Bansang and Basse to the new regional system.

Figure 37: Electricity generation in scenario three (renewable ambitions)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SolarPV	-	-	-	-	7,173	8,502	10,01	13,17	16,87	21,23	38,15	49,31	62,22	76,34	92,00	106,7	111,0	135,9	152,6	169,5	188,1	197,4	207,6
Wind	-	-	-	98.55	990.9	1,330	3,176	11,05	19,52	30,95	33,93	33,84	33,84	33,84	33,93	33,84	33,84	33,84	33,93	33,84	33,84	33,74	33,83
Biomass 40MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass 5MW grate furnace	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy from Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HFO new	-	-	24,86	39,95	68,46	93,62	113,2	146,4	160,8	153,7	3,087	3,087	3,087	3,087	3,087	3,087	7,487	12,44	34,64	68,94	146,9	187,8	227,2
HFO existing	208,3	217,8	198,3	215,6	213,4	220,6	249,6	246,3	240,3	253,0	5,068	5,068	3,168	3,168	3,168	3,168	18,63	31,44	38,64	38,54	-	-	-
LFO new	-	-	-	-	13,22	54,56	85,80	128,8	160,0	195,8	83.55	936,1	3,783	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	11,98	4,780
LFO existing	6,023	6,192	6,385	8,208	8,507	8,507	14,37	9,953	14,34	14,34	134.9	235,7	235,7	235,7	235,7	235,7	235,7	-	-	-	-	-	-
OCGT150MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT 300MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 70MW	-	-	-	-	-	-	-	-	-	-	337,0	365,9	396,6	428,7	465,3	502,8	521,2	521,2	522,6	521,2	521,2	521,2	522,6
Coal 125MW CFB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal 250MW PC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-	-	-	-	386,4	385,4	385,4	385,4	386,4	385,4	385,4	385,4	386,4	385,4	385,4	385,4	386,4

Figure 38: New generation capacity built in scenario three (renewable ambitions)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OCGT150MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCGT 300MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LFO new	0.00	0.00	0.00	0.00	20.00	15.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HFO new	0.00	0.00	9.00	17.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00
Energy from Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 40MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass 5MW grate furnace	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 250MW PC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 125MW CFB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal 70MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SolarPV	0.00	0.00	0.00	0.00	4.09	0.76	0.85	1.82	2.11	2.49	9.60	6.43	7.37	8.06	8.80	8.54	2.48	14.22	9.26	9.92	10.61	5.31	5.49
Wind	0.00	0.00	0.00	0.00	1.36	0.52	2.80	12.00	12.90	17.40	4.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.2. COSTS, BENEFITS, RISKS AND BARRIERS

In this scenario the costs are higher than the first scenario, as more demand needs to be met. The average cost per unit of demand is broadly comparable to the first scenario.

The costs are more heavily weighted towards capital rather than operational costs, as coal and hydro power plants are quite capital intensive, as are solar PV and wind. However, the operating cost is lower. The Gambia is spending less on fuel in this scenario as the operational cost of coal and renewable technologies are less expensive per MWh generated than oil-fired engines.

Table 5: Key cost indicators for scenario three (renewable ambitions)

	Units	2011-2015	2016-2020	2021-2025	2026-2030
Demand (expressed)	GWh/year	284	592	851	1,087
Renewable generation	% demand	1%	20%	58%	53%
Unsupplied energy (of expressed)	%	4%	3%	3%	2%
Fixed operational costs (ex. Interest)	US$m (2011 real)/yr	2	5	9	12
Variable operational costs (inc. fuel)	US$m (2011 real)/yr	40	68	23	36
Capital recovery (capital and interest)	US$m (2011 real)/yr	6	34	93	124
Emissions	ktCO2	166	319	373	493

CO_2 emissions per unit of demand towards the latter part of the simulation are lower than the other two scenarios at $450tCO_2$/GWh due to the high renewable penetration.

This scenario very significantly reduces exposure to oil prices and increases diversification by using hydropower, coal generation, wind and solar PV. The exposure to oil prices is completely eliminated in certain years. As with scenario two, the scenario does add a new exposure to coal prices.

The steam turbine coal plant and regional hydropower project should allow the grid to be more stable and reliable (due to increased inertia on the system). Greater stability and controllability of the system in turn allows greater integration of renewable sources. The low cost hydro reduces the financial penalty of high renewables targets, allowing the Gambia to pursue a more ambitious goal for renewable penetration. Again, in this scenario the Gambia has the opportunity to become an active seller of power.

Again, the finance required in this scenario is significant, and it is needed earlier than in scenario two. This means a strong commercial and governance framework will be important to enable investment.

Barriers to achieving this scenario include investor confidence, delays or cancellation in regional integration, delays or cancellation of the hydropower project and a risk of decreased demand if consumers have an economic barrier to connect and use electricity.

4. ADDITIONAL DISTRIBUTION INVESTMENT

The scenarios above consider only transmission rather than distribution investment.

Distribution investment required can be broadly estimated by considering the increase in demand being met. In 2010, demand in the Gambia was 208 GWh with a peak demand of 43 MW.

This demand increases in all our scenarios. In scenario one demand reaches 893 GWh by 2032 and peak demand of 190 MW. In scenarios two and three demand reaches 1,287 GWh by 2032 and peak demand of 277 MW. To put this in context, the population is expected to increase from an estimated 1,722,196 in 2010 to 3,369,926 in 2032 (World Bank Diagnostic Review).

Aldwych, 2009, suggests that in the city an average domestic customer connection is 1.2kW, whereas villas (with more affluent customers) will have a larger average connection of 4kW. The same study also estimate 12m between connections in an urban area (83 connections per km). To put this in context, an energy efficient light bulb is about 10-20W, a computer or a ceiling fan might use 100-200W, a refrigerator might be 1kW or less (depending on performance), a domestic kettle is 2-3kW and an air conditioning unit might be 3-5kW.

In the estimate for the distribution network expansion, we assume an average peak demand per household (or compound) of around 1.2 kVA (it is assumed that most of the expansion will be for smaller demand customers. We also assume a lower density of connection (75 connections per km).

On this basis, the cost to expand the distribution network can be estimated at €2,903/kVA peak (see Table 6).

Table 6: Cost for a medium capacity increase (AF-Mercados EMI data)

	€/kVA (Peak)	€/Client
Substations (MV)	100	120

Lines MV	444	533
Cable MV	2,222	2,667
Transformers (MV/LV)	150	900
Lines LV	278	333
Cables MV	1,111	1,333
Meter	625	150
Total	**2,903**	**3,603**

That gives an estimated total investment cost of €427m in scenario one (only partial electrification) and €679m in either scenario two or three (full electrification).

5. INVESTMENT PROFILE IN EACH SCENARIO

Based on each of the three scenarios, we can consider the capital investment that would be required to achieve each of them.

In scenario one, the current path, the investment required is reasonably steady, as shown in Figure 39. There is a peak in 2030 with WPP interconnection, but otherwise investment does not exceed US$50m.

Figure 39: Scenario one (current path)
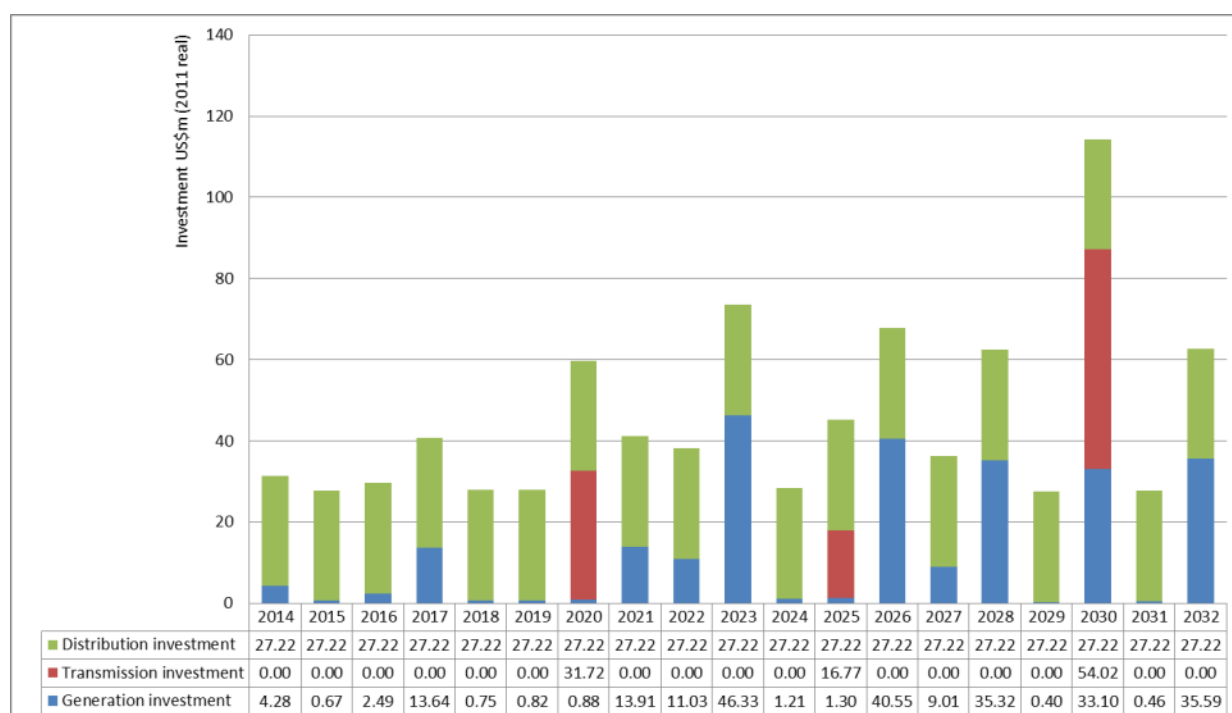
By contrast, scenario two (reliability) has much higher investment requirements as shown in Figure 40. In particular, there is a very high investment requirement in 2025, which is the year assumed for WAPP interconnection. In 2025, both coal power plant and generation investment is required.

Overall investment requirements are much higher. This is partly due to the choice of plant (coal and renewables both have higher capital costs than oil, although the operating cost is lower). It is also due to the higher demand being met, as in this scenario greater electrification is achieved than scenario one.

Scenario three, shown in Figure 41, has even earlier investment requirements as the WAPP interconnection is in 2020, and at the same time both the hydro and coal projects are developed.

Figure 40: Scenario two (reliability)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
■ Distribution investment	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29
■ Transmission investment	0.00	0.00	0.00	0.00	0.00	0.00	15.37	0.00	0.00	0.00	0.00	117.8	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ Generation investment	65.06	24.63	17.34	21.94	17.96	13.11	27.55	14.25	43.43	9.23	10.79	257.1	13.20	91.22	47.20	50.98	87.64	18.20	20.71

Figure 41: Scenario three (renewable ambitions)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
■ Distribution investment	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29	43.29
■ Transmission investment	0.00	0.00	33.16	0.00	0.00	0.00	100.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
■ Generation investment	56.58	24.96	8.46	30.84	27.20	34.33	340.50	42.43	48.62	53.18	58.07	56.36	16.38	93.83	61.09	65.48	70.06	35.05	68.88

6. CONCLUSIONS FROM THE SCENARIOS

Scenario one is not very desirable. It exposes consumers to a high risk in the case of increasing oil prices. It also has very delayed regional interconnection and the generation mix would remain based on oil engines, which are not good for grid stability. This means high carbon intensity and low system reliability. Access to electricity is only improved slowly.

Scenario two increases diversification. It has coal generation with a steam turbine, which allows the grid to be more stable and reliable. It also allows greater integration of renewable sources. The exposure to oil prices is reduced, although not completely eliminated. Access to electricity is achieved for most of the population by 2025.

Scenario three has higher diversification and earlier regional integration. The regional hydro project allows access to low cost and low carbon generation. Access to electricity is achieved for most of the population by 2020.

Scenario two or three are more desirable than scenario one. The key difference between scenario two and three is that the regional hydro project is implemented and interconnection takes place earlier. The third scenario has clear environmental benefits, with over 50% of demand being met by renewable electricity. It also has economic benefits, because of the low cost of the power from the hydro project in our assumptions. However, the choice will not be solely in the hands of the government. Moving from scenario two to scenario three would require regional decisions to be made, on which the Gambian government cannot have absolute control, although they will have the ability to influence within the region.

What is clear from the scenarios analysis is that the "best future" for the Gambia is through integration in the region and if possible the development of OMVG hydro project. This is a very strong signal towards "integration" and we recommend that strategic and policy decisions for the power sector should put emphasis on trying to achieve regional integration.

Beyond what can be seen in these scenarios, it is also important to remember that the cheapest unit of electricity is the one that you don't use, so a good energy efficiency strategy can help to control the cost of electricity to consumers and improve their ability to afford the electricity they need. Part of this approach is to understand and reduce losses in the network, which are currently high.

IV ELECTRICITY STRATEGY AND ACTION PLAN

1. GUIDING PRINCIPLES AND STRATEGIC ORIENTATIONS

The Electricity Strategy and Action Plan aim to address the key barriers to increasing the generation and grid capacity, the development of renewable energy and meeting all demand, including currently suppressed demand in isolated or unsupplied systems.

The guiding principles of the strategy have been established based on stakeholder discussions, research and the scenario modelling discussed in the previous sections.

In the inception phase we established the following overall principles:

- There is an urgent need to increase access to reliable electricity to support economic development.
- Developing a strategy for the electricity sector will allow new potential investment proposals to be evaluated as part of overall objectives.
- Renewable electricity in the Gambia should be considered as a mechanism for poverty reduction, and therefore is appropriate only when it can be delivered at an equal or lower cost to consumers than the cost of conventional generation (heavy fuel oil and light fuel oil). External funding sources or credit lines may be an option to deliver renewable energy at cost parity to consumers.
- Private sector investment should be encouraged by developing a clear and transparent investment framework.

The table below summarises the proposed objective in terms of investments from the analysis in the previous Sections. This objective will need to be tested and validated in the forthcoming strategy workshop.

Table 7: General objective for electricity strategy

Category	Objective
Conventional power sources	– Without regional integration, HFO and LFO are important, and even with regional interconnection they continue to play a role.
	– Coal has an important role if regional interconnection is achieved.
Renewable energy	– Hydro OMVG scheme highly desirable. Politicians should consider this in negotiations.
Rural electrification	– Solar PV and wind play a role in rural electrification. Extent of role may depend on international levels of support.
Transmission and Interconnection Plans	– Microgrids gradually expand into national network.
	– Regional interconnection is highly desirable, as it allows larger plant units to be used.

Some potential barriers have already been identified, and are discussed in more detail in Section 2 and 3. These will need to be addressed for the strategy to be successful. Again, these barriers and potential mitigating actions were confirmed at the strategy workshop.

2. THE CURRENT SITUATION

2.1. ACCESS TO ELECTRICITY

There is a growth of 10-20% per year in met demand. Much demand is currently suppressed, so this figure has the potential to increase still further. Load shedding is frequent, and it is common practice for many businesses, hotels and health facilities to rely on self-generation from large onsite diesel-fired generation units and occasionally solar PV units to support their businesses during load shedding or outages. Data on these back-up or off-grid systems is not available.

2.1.1. GREATER BANJUL AREA

NAWEC aims to provide a 24 hour service within the greater Banjul area but does have to shed load at times. Kotu Power Station (NAWEC) and Brikama Power Station (Global Electric Group IPP) supply demand in the system, along with a single small wind turbine. We understand that at least two independent investors are considering investing in new IPPs to connect to the system, which may include additional investment in transmission and distribution capacity. New planned lines in the Greater Banjul area should be in place by end 2013. This includes a 132kV power line between the two power stations.

2.1.1. PROVINCIAL SYSTEMS

Electricity access outside the greater Banjul area is just 6-22%. Lack of reliable electricity is affecting all aspects of life and business. For example, in off-grid areas it is common for old car batteries to be used for charging mobile telephones.

The provincial power stations have limited operating hours in the range of 12-14 hours per day. Anecdotal evidence and our experience on visiting two provincial power stations suggest that they have mechanical and maintenance issues that hinder their generating capacity. Fuel delivery is also a challenge, particularly in the more isolated systems. A light fuel oil delivery to Basse takes two days from Banjul.

NAWEC is obliged to supply these provincial capitals. However, they are mostly supplying customers on the lowest domestic tariff, using expensive diesel generation. They have considered separating the supply to the provinces from their supply in the greater Banjul area. NAWEC see the regional supply as essentially a social project. By separating it from their other supply activities they may be able to access more funds, for example through donor agencies.

While this was not discussed, the fact that NAWEC is making an apparent loss on supply in these provinces may discourage a longer and more stable operating schedule, and may make it more difficult to justify the required maintenance to keep the plants operating reliably.

NAWEC is considering a wider 132kV "backbone" to link the country, although a more detailed feasibility study would need to be completed and funds would need to be raised. They are also considering a 33kV link from Bansang to Basse and from Kuar to Farafenni. These provincial links are already part-funded ($20m raised out of $30m required). 8MW of heavy fuel oil generation is also planned split between the Farafenni and Basse systems (4MW each).

2.2. NETWORK AND LOSSES

The transmission and distribution network for the country is owned and operated by NAWEC. The transmission voltage is 33kV and the distribution voltage is 11kV with 400V lines to customers. Technical losses on the transmission and distribution network are not adequately metered and reported. There seems to be a lack of understanding of the precise causes of losses and costs. Clarifying these points could make sure that cost reduction efforts are correctly targeted.

2.3. TARIFFS

The current electricity tariff structure includes lower tariffs for domestic users and the highest tariffs for hotels. This is not based on the cost to serve these consumers, but is instead based on payment capacity and social policy. The revenue from tariffs reportedly does not meet NAWEC's overall cost of service.

Cost-reflective tariffs for consumers might equalise the incentive on NAWEC to connect and reliably supply all load. In many countries, the charges for domestic users are higher than for commercial users, to reflect the higher cost and losses of connecting and supplying smaller loads through the distribution system. However, we understand that there are serious concerns about affordability for domestic uses in the Gambia that would need to be addressed and managed for this to be an acceptable policy.

2.4. LEGAL, REGULATORY AND INSTITUTIONAL FRAMEWORK

2.4.1. LEGAL CONTEXT

The Electricity Bill 2005 covers the key areas of the Gambian electricity sector and has the following objectives:

(a) promote the generation, transmission, supply, dispatch and distribution of electricity in The Gambia;

(b) set standards relative to electricity services;

(c) promote electricity efficiency and supplies;

(d) ensure sufficient and reliable electricity supplies for the population and the economy of The Gambia at just and reasonable rates;

(e) establish cost-effective and reliable electricity supplies for all classes of consumers;

(f) effect a transition to a private investor controlled and operated electricity sector in which, through competition, where feasible, and regulation in non-competitive markets, prices accurately reflect the costs of efficient production, transmission, dispatch, and distribution of electricity;

(g) establish a framework for the regulation of the electric sector;

(h) assign responsibility for overall policy development in the electric sector to the Department of State and relieve the Department of State from regulatory responsibilities in the electricity sub-sector;

(i) encourage private sector investments in electric sector activities;

(j) encourage domestic and foreign private capital participation in the electric sector;

(k) promote competition in the electricity market; and

(l) encourage the production of electricity through the use of renewable energy.

2.4.2. ENERGY POLICY

Government overall objectives for the sector (Ministry of Energy Draft Strategic Plan, 2010-2014) are to:

- Improve and expand, efficiently, existing energy supply systems through private sector partnership with the public sector.
- Promote a domestic fuel sub-sector, which clearly focuses on sustainable management of forest resources;
- Widen the population's access to modern forms of energy so as to stimulate development and reduce poverty;
- Strengthen institutional and human resource capacity and enhance Research and Development (R&D) in energy development;
- Provide adequate security of energy supply.

The strategic plan recognises the limited access to electricity, the relatively high electricity tariffs and the challenges of a high reliance on imported oil. Relevant objectives include:

- Increase generation, transmission and distribution capacities;
- Improve access to electricity and safe drinking water;
- Provide affordable electricity and water;
- To ensure efficient operation of NAWEC; and
- Promote the use of renewable energy and energy efficiency.

2.5. GOVERNANCE AND INSTITUTIONAL REFORM

The independence and freedom to operate of the regulator, PURA, appears to be constrained by both political involvement and financial constraints (many regulated entities are not paying their regulatory fees). PURA has some powers in terms of recommending the Secretary of State to issue licenses, and advising on tariff reviews. However, much responsibility for the electricity sector is retained by Government. This includes the final decision on tariff reviews. Electricity tariffs are understandably an important political issue in the Gambia, and this may limit the industry, Government's and regulator's ability to act freely. The fact that the President is also Minister for Energy shows the high level of importance put on energy issues, but may raise the political stakes in the area of energy.

PURA have chosen to limit their involvement in IPP negotiations to maintain their independence, but this may also limit their scope of influence. We understand that they only received a copy of the PPA between NAWEC and GEG within the last year, although it is expected that they would have more ability to access future PPAs.

There is general consensus that NAWEC requires restructuring and stronger management and financial reporting to tighten up on costs and be clearer about where costs are allocated and what cross subsidies exist. However, there may be more fundamental problems that are not solved by restructuring. For example, NAWEC seems to currently employ around 1,000 people. As a state-owned monopoly, there may be political difficulties in making efficiency savings. More generally, businesses have suggested that there are challenges in making staff reductions because of the risk of repercussions (for example by sabotage, or through influential friends or relations).

2.6. CURRENT STATUS AND BARRIERS TO ELECTRICITY SECTOR DEVELOPMENT

2.6.1. CONVENTIONAL POWER

At present, fuel oil generation is perceived as excessively expensive. Alternative conventional generation sources should be considered.

Conventional generators may need to operate more flexible to accommodate variable renewable energy as the system develops. Therefore more flexible PPAs may need to be developed. There are also no arrangements in place to use balancing power, including from around 35MW diesel back-up generators dispersed around different customer sites.

2.6.2. RENEWABLE POWER

The absence of a fully functional legislation and laws to regulate the renewable energy sector has delayed implementation of projects, although a demonstration wind energy project does show what is possible.

The development of renewable facilities for electricity production is still constrained by different economic factors. In spite of the high electricity prices in the Gambia, the major obstacle to the development of alternative sources (mainly solar energy) is the additional cost relative to conventional energy sources. Nonetheless, other barriers are currently hindering the implementation of renewable technologies.

- Most of the renewable technologies remain expensive and uncompetitive with conventional energy sources, thus the absence of clear financing mechanisms prevent wider development.
- Legal, regulatory and institutional barriers need to be addressed to implement and ensure viability of renewable facilities.
- Positive externalities (economical, environmental and social) from renewable power generation are not considered in the economics.
- There is incomplete data and sometimes contradictory data on renewable energy resources (particularly wind).
- The lack of accreditation and certification for these facilities is a drawback for the development of a national industry.
- Insufficient professional skills to guarantee the installation and operation of these facilities.

There are also constraints on the type of renewable resources that can be used.

- The wind resource is primarily on the coast and inland developments may not be economic (opinion is divided on this issue). New developments at a larger scale will be constrained by the difficulties of importing suitable cranes for large wind projects. Other concerns in developing new projects are that bird impacts have not been studied to determine best sitting. There are also grid stability concerns, as the wind variability may not be able to be managed well by the current generation mix. There are also safety concerns, such as the potential for blade shearing, in populated areas.
- Dust on solar PV panels is a significant issue for performance. These panels will need to be cleaned regularly, and a plan to use recycled water is likely to be required by NEA.
- The use of fuel wood and residues from wood processing for electricity generation is not encouraged because wood and charcoal are used extensively for domestic cooking and deforestation is a major issue for the Gambia. Groundnut briquettes have been proposed as a solution to these domestic cooking issues. Greentech has a facility to process waste groundnut shells to briquettes that are usable for cooking. Technically these briquettes could be used for electricity generation. However, Greentech prefers to remain true to their original objectives of reducing deforestation.
- The use of other types of biomass is quite low due to the limited availability of agricultural waste and other potential sources. Biogas has been considered, but there are issues with collection. There may also be sustainability issues as cow dung (manure) is used on farms at present. There is also an explosion risk.
- Cashew and jatropha energy crops are reported to grow well in the Gambian climate. Views from stakeholders on the use of energy crops are mixed. Proponents support the benefits that new industry could bring to the Gambia and greater energy self-sufficiency. However, there

are serious concerns about land use. Overall, it seems that before significant energy crop development is considered, a wider strategy on agricultural land use for energy crops should be developed to ensure that food production is not constrained or undesirable pressure is put on forestry.

More discussion of resource availability and potential generation sources is in Annex 2.

2.6.3. HYDROPOWER AND WAPP

The Gambia is part of the WAPP (West African Power Pool) a regional organization for power within ECOWAS (Economic Community Of West African States), which is currently developing the rules for a regional market and has already approved a regional system expansion plan for transmission.

Until now, WAPP has been primarily focused in planning the expansion of regional transmission lines. However, in recent years some efforts have been made to complement the infrastructure developments with other aspects needed to implement a regional market.

The regional market is envisaged as developing in stages:

Phase 1: from now to around 2015, when most regional transmission infrastructure is expected to be commissioned. This phase includes formalising trading arrangements, agreeing transmission pricing and establishing a regional regulator.

Phase 2: is based on the preparations carried out during the phase 1, and should include bilateral agreements with transit through third countries, short term exchanges through day ahead markets, regional transmission pricing and regional System Operator/Market Operator functions.

Phase 3: is a long term vision which would include regional optimisation of operation.

WAPP has approved a regional master plan for infrastructure development, with timings for the different projects. This master plan is organised into the following sub programs (see following figure):

- Coastal Transmission Backbone Subprogram (Côte d'Ivoire, Ghana, Benin/Togo, Nigeria).

- Inter-zonal Transmission Hub Sub-program (Burkina Faso, OMVS via Mali, Mali via Côte d'Ivoire, LSG via Côte d'Ivoire).

- North-core Transmission Sub-program (Nigeria, Niger, Burkina Faso, Benin).

- OMVG/OMVS Power System Development Subprogram (The Gambia, Guinea, Guinea Bissau, Mali, Senegal)

- Côte d'Ivoire-Liberia-Sierra Leone-Guinea Power System Re-development Subprogram (Côte d'Ivoire, Liberia, Sierra Leone, Guinea).

- WAPP Strategic Generation Subprogram (Emergency Power Supply Security Plan).

Sambagalou and Kaleta are two hydro projects which are expected to be developed by the OMVG (Organisation pour la Mise en Valeur de la fleuve Gambia, or Gambia River Basin Organisation).

Sambagalou would have an installed capacity of 128 MW and Kaleta of 240 MW. Senegal, Guinea, the Gambia and Guinea Bissau will receive 40%, 40%, 12% and 8% respectively of the electricity generated by the two dams. Total investment for both power plants plus 1,600 km of associated transmission lines is of the order of US$1.3 billion.[2] In principle, financing institutions have promised US$800 million[3] and the initial agreement was to build first Kaleta and later Sambagalou based on private sector participation.

The partner countries were expected to ratify legal instruments as a first stage to developing the projects, but this has not happened. Anecdotally, it has been suggested that the lack of progress in the projects may be due Guinea considering proceeding with the Kaleta project unilaterally. In any case, it seems that the progress has been delayed on this project and its future development is still uncertain.

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[2]   http://www.developingmarkets.com/sites/default/files/digital-reports/dma-senegal-report-2011/files/assets/basic-html/page18.html

[3] Financing: BAD: USD 140 million, BEI: USD 78,6 million, BM : 90 million US, AFD: 42.9 million US, EBID: 30 million US, KfW: 35.5 million US, Abu Dhabi: 20 million, BOAD: 27.25 million US, IDB: 208 million US, Non financed : 387 million US

Figure 42: WAPP regional sub-programs
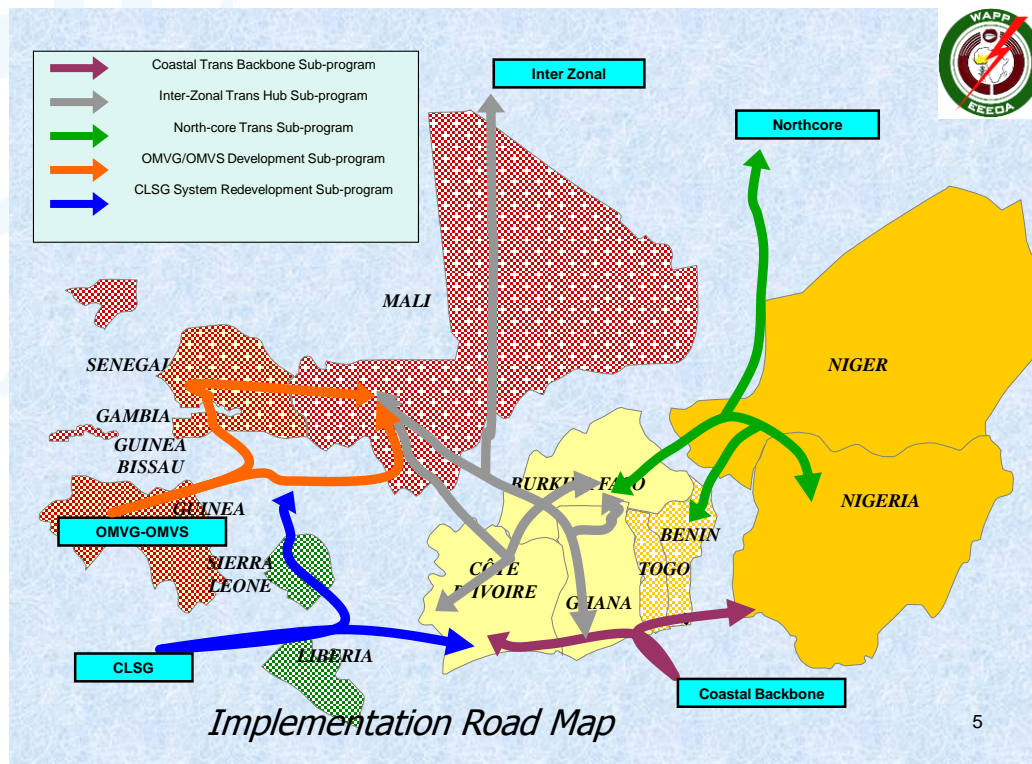
Figure 43: Sub-program involving the Gambia in more detail
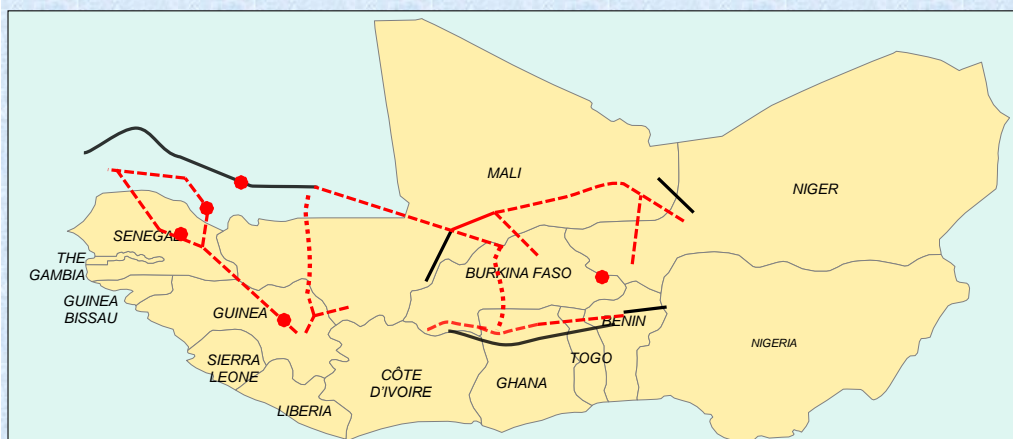
- Hydropower sites at Kaleta, Sambangalou + 225 kV Interconnection Line - IMPLEMENTATION **FINANCING REQUIRED** : 2015
- 225 kV Nzérékoré (Guinea) – Fomi (Guinea – Bamako (Mali); PRE-INVESTMENT - 2016

Otherwise the Gambia is a relatively flat country, and potential for hydropower seems limited. The Lahmeyer Renewable Energy Master Plan (2006) does not consider it as an option and Enrique Rodríguez Flores (2010) dismisses traditional hydro as an option because of the lack of resource.[4] A diagnostic study by NOVI Energy for World Bank (2010) points out that while there are currently no installed hydro driven generators in The Gambia, their discussions with REAGAM suggested a

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[4] Master Plan for Renewable Energy based Electricity Generation in The Gambia, Dissertation by Enrique Rodríguez Flores (2010)

potential for run of river, mini, and micro hydro opportunities. These possibilities have not been identified or quantified, but overall the potential seems limited and this study therefore only considers hydropower in the context of regional OMVG opportunities (see Annex 2 for more discussion).

2.6.4. COMMERCIAL SUSTAINABILITY

NAWEC appears to have been struggling financially for many years, and is not currently able to meet the costs it incurs in running the system, leading to inadequate maintenance and development of the system.

PURA's 2010 annual report indicates that a rise in tariffs by NAWEC is not leading to the expected level of increase in revenue. They note significant levels of debt to NAWEC from public authorities, including central and local government, which PURA suggests may need to be renegotiated.

Public sector and domestic users are also increasingly being moved to prepayment meters to ensure revenue recovery. Businesses are billed monthly and report that payment terms are strictly enforced. This includes Government Departments and even some street lighting, although it seems certain aspects of the military may be exempt.

PURA's annual reports also indicate that NAWEC have not paid their regulatory charges, perhaps reflecting their current financial difficulties. Lack of revenue for regulatory agencies may be a concern as it constrains their ability to provide regulatory oversight.

NAWEC's annual accounts are not prepared in a way that makes it easy to identify the issues they are suffering from. NAWEC's power and water accounts are combined. It is important that (at least in an accounting sense) water is unbundled from power - since it is not clear whether the most serious problems are in water or in power, or where cross subsidies exist.

2.7. MEASURES TO FACILITATE PRIVATE SECTOR INVESTMENT

The Gambia's electricity market is relatively small, and unlikely to be of interest in its present form to larger multinational utilities. Having said this, there appears to be a healthy level of investment interest from smaller and medium-sized international investors.

As well as the existing IPP operated by GEG, other investors are expressing an interest in developing 30-50MW heavy fuel oil IPPs. We met a representative from Aldwych International, who hopes to invest in a 35 MW heavy fuel oil project with enabling grid infrastructure (they will own the grid assets, which will be operated by NAWEC). We understand that Jacobson are also negotiating for a 40MW heavy fuel oil IPP. Under the IPP negotiation process, the fuel cost for IPPs is typically passed through in Power Purchase Agreements (PPAs). There are also a significant number of potential investors in renewable energy technologies. These include firms dedicated to developing renewable projects, such as Gamwind, a number of solar system installers, businesses with electricity requirements like the telecommunications company Qcell, and community projects developed under the GEF-UNIDO microgrid scheme.

The new projects being considered appear to be processed as non-competitive procurements. We understand that potential investors approach the Ministry of Energy. The President provides initial approval to proceed with the negotiation. If approved, a task force is set up, including NAWEC, the Ministry of Energy, Ministry of Justice, Ministry of Finance, and the Ministry of Trade and Export. There is always the same member at each meeting. PURA is invited, but prefer only to be involved at final stages to maintain their independence. Each project negotiates its own PPA, and the EIA is carried out after the commercial negotiation process. The process can be a matter of months.

We are concerned that this individual negotiation process may lead to a lack of checks and balances in IPP deals. PURA may provide some of this in their final review of the proposal before it is approved. However, they may not have the power to veto and the benefits of competition to get the lowest price are totally lost.

It seems that there is a wider need for long term planning in the sector to decide which investments are actually needed in advance of approaches from bidders. The approach at present is reactive rather than proactive.

The availability and cost of finance is likely to be a barrier to participation in the power sector by local companies. According to the industry representatives we have spoken to, assets in the Gambia are not seen as sufficient for collateral by international banks, and Gambian banks charge prohibitive rates of interest (20-26%).

Encouraging private developers to invest in the energy sector, both in conventional and renewable technologies, is essential to boost the development of the power sector and to allow the economic and social development that reliable power enables, as well as directly creating job opportunities in the power sector itself.

Some important enabling activities will include:

- To identify and disclose technology potential (for renewable energy technologies), targets and planning conditions to allow investors to see the profitability of the investment.
- Implement, maintain and continuously improve the required regulatory and institutional framework that better adjusts to the prevailing premises, with the objective of raising and fostering interest in power investment.
- Implement, maintain and continuously improve a procurement process for new power plants that fosters a more competitive approach and can deliver greater value for money to consumers.
- Establish clear and appropriate financing and fiscal mechanisms which attract the private sector to invest in renewable energy technologies.
  - Set forth a reliable payment flow to support project financing. This may be through guaranteed tariff payments over a fixed period of time.
  - Some tax waivers (import duties, etc.) are already in place and should be better publicised.
  - Consider working with international agencies to develop a credit line for community and small business renewable energy or other power generation projects.
- Disseminate information in order to raise public awareness concerning the benefits and opportunities which may result from the development of renewable energy generation projects.
  - Information dissemination and awareness campaigns.
  - Educational packages for engineers, technicians, designers, etc.
- Build the required capacities in the appropriate institutions, promoting R&D activities, technology transfer, standards and international cooperation which foster private sector investments.
  - Pilot projects are already in place in the form of the Gamwind project and the GEF-UNIDO projects that are under development.
  - Training programs for installers through workshops and seminars.
- Other areas that may need to be considered for capacity building might include: project finance training, and guidance on international best practice in procurement, particularly in managing IPP and PPA negotiations, including the importance of managing potential conflicts of interest and ensuring appropriate separation from potential bidders
- We suggest that greater online availability of data may encourage more international interest.
- Land use rules do not currently seem to be a constraint for power plants. However, robust procedures should be developed to manage encroachment onto exclusion zones around power projects. This should include an action plan developed between the project developer and the local authorities on the responsibility for discouraging building on the exclusion zone and removing illegal development that does occur.

2.8. GRID CAPACITY AND STABILITY

The current levels of unplanned outages and damage caused to electrical appliances demonstrate that that power quality is already a problem.

Renewable generation will create additional challenges in operating plants, by introducing the need to ramp to balance increases or decreases in generation. There are not currently sufficient controls to respond rapidly to ramp requests.

Control of the Greater Banjul area network is currently from Kotu power station. NAWEC would like a mini national dispatch centre in Welingara by 2014/15, but are still looking for funding. At present the two stations are controlled by phone only. There is no real time metering. The provincial networks are controlled from their respective stations. The lack of metering equipment to monitor losses also seems to suggest that system monitoring would need to be significantly improved to manage variable generation.

The Gambia does not yet have a grid code, and there is no provision for a grid code in the 2005 Electricity Act. A grid code is a technical document containing the rules governing the operation, maintenance and development of the transmission system and co-ordination of the actions of all users of the transmission system. This would be a requirement for interconnection with a wider WAPP. It is also important in ensuring a stable and reliable grid system, with all participants behaving appropriately.

New conventional generation is likely to be required, along with renewable generation, to adequately meet existing as well as suppressed demand. New conventional IPPs should be able to respond to the requirements of the system, with obligations placed on them through appropriate PPAs, grid code and licence conditions.

The current network is not able to take significant additional power capacity, as evidenced by a requirement on new IPPs to build transmission upgrades. New transmission development would be

required to connect additional generation. It may be appropriate to connect provincial capitals to either the main greater Banjul system to balance generation more effectively.

These needs for more robust system control are likely to form part of an appropriate long term strategy for the sector.

2.9. SKILLS

The Gambia appears to have a shortage of the relevant skills for the power sector.

The lack of technical skills is felt at all levels: engineers, mechanics and technicians. Often these skills are recruited from outside the country, from the wider ECOWAS region, or German, Lebanese or French expats. GEG employ around 10 expats, for example.

The Ministry of Energy, NAWEC and PURA also expressed a need for more capacity in the power sector. The Ministry of Energy includes "capacity building for MOE, NAWEC and other stakeholders" as part of their Draft Strategic Plan 2010-2014. Specific capacity-building programs are not identified. Management and project finance training may be beneficial, particularly for managing IPP processes.

The Ministry of Energy has specifically requested that their team is closely involved in the development of this project to build their capacity.

2.10. COMMUNITY ENGAGEMENT

Communities who do not currently have access to the electricity network are one of the main groups with potential to benefit from renewable electricity support. However, there are serious challenges for investment by communities in the Gambia. It is difficult for them to access finance and develop the skills and knowledge required.

Donor agencies may wish to consider the opportunities for credit lines or grant schemes to support such schemes. Gambian experience does show some interesting examples of how these challenges could be overcome with appropriate funding.

The current GEF-UNIDO projects provide examples of community engagement in electricity projects. The Tanji fishing community are looking to use wind power for ice production to preserve fish. Solar power is being used for a tailor workshop for M'Bolo's women's training centre and for sustainable agriculture projects.

Schools commonly provide a focal point for community engagement for EIAs. It may be possible for them to provide a similar focal point for community engagement in renewable schemes, allowing students to benefit from opportunities to use electronic equipment like the sewing machines above and also computers. Hospitals and medical centres particularly need stable and reliable electricity supplies to preserve medicine and operate medical equipment. Currently this need is met by onsite diesel generators in many cases. The cost of operating these back-up systems diverts medical funds from other areas. There may be options for targeting funding through schools, hospitals or other local bodies to develop small microgrid schemes. These schemes have potential to be at least partly self-financing by selling to local consumers.

3. KEY CHALLENGES

The key challenges are summarised in Table 8 overleaf.

Table 8: Challenges and potential mitigating actions

Challenge	Description	Current activities and proposals (already underway or planned)	Additional actions required
Insufficient transmission and distribution network	• Greater Banjul Area is the main system and aims for 24 hour supply. • Provincial networks are isolated and have 12 hour supply. • Access to electricity outside the Greater Banjul area is just 6-22% • Cost to connect may form a barrier to domestic customers wishing to connect to the network, delaying electrification.	1. New planned lines in the Greater Banjul Area include a 132kV power line between the two power stations by end 2013. 2. Considering a 33kV link from Bansang to Basse and from Kuar to Farafenni (part-funded, $20m raised out of $30m required). 3. Considering a wider 132kV "backbone" to link the country, although a more detailed feasibility study would need to be completed.	1. Consider the costs and benefits of connecting the isolated regional systems and increasing capacity on the existing network. 2. Consider reducing or socialising the cost of connection for small consumers. 3. Rural electrification strategy.
Insufficient generation to meet demand	• High levels of planned and unplanned load shedding both in the Banjul Area and in the provinces.	4. Recent expansion of capacity at Brikama (9MW). And further expansion at the same site planned (two 6.4 MW). 5. Negotiations for a major new IPP (30-50MW). 6. 8MW of heavy fuel oil generation is also planned split between the Farafenni and Basse systems.	4. Define Government priority investment opportunities based on energy scenarios. 5. Fund full feasibility study for near term options. 6. Define a strategy, including both network and generation. 7. Consider running a tender process for larger opportunities.
Lack of controllability in the network, reliability and quality of supply	• High levels of planned and unplanned load shedding. • Voltage and frequency drift that can damage electronic equipment. • The need to manage variable renewable generation would introduce greater challenges and require more controllability. • Current PPA with IPP does not allow for the need to control generation. • Lack of metering and control equipment.	7. Control Centre planned for Greater Banjul Area, but not yet funded.	8. Grid Code requiring certain performance standards to be met by generators and NAWEC. 9. Introduce central controllability for certain generators and demand. 10. Introduce obligations on generators in PPAs to provide certain ancillary services. Make ancillary services PPAs accessible to a wider range of generators, including smaller onsite back-up generators, and consider allowing controlled initial shedding of certain demand in return for favourable tariffs. 11. Consider introducing real time hourly metering for generators, major demand customers and at key points on the system. 12. Consider reporting on and ultimately incentivising NAWEC based on reliability (for example, customer minutes lost) 13. Provide incentives for flexibility and controllability in PPAs for controllable plant
Lack of regional interconnection	• No interconnection with wider West Africa.	8. Member of the WAPP 9. Plans for interconnection under OMVG, but progress slow	14. Consider policy emphasis on regional interconnection and prioritising the OMVG at inter-Governmental level. 15. Considering alternative plans if OMVG does not proceed.

Challenge	Description	Current activities and proposals (already underway or planned)	Additional actions required
			16. Co-ordinating Grid Code and other regulatory changes to ensure ultimate compatibility with WAPP.
High levels of losses	• Losses are high and cannot be accurately measured or attributed to technical and non-technical elements. • Need to introduce metering point in the network to better assess flows, demand and loses in different points of the grid.	10. Widespread prepayment meter roll-out, including public sector.	17. Accurate system metering to identify where losses are occurring, so that mitigating action can be taken. 18. Consider the costs and benefits of using higher voltage lines with lower losses and replacement of older existing lines.
Insufficient private sector investment	• Negotiation with potential investors is opaque. • Current IPP (Brikama) was built by the monopoly oil importer (GEG, part of GAM Petroleum), so is not fully independent • NAWEC ability to pay, and therefore credit-worthiness	11. One IPP in place, GEG Brikama plant. 12. Negotiations underway with various potential IPP investors	19. Tendering process for clearly defined investment opportunities. 20. Standard PPA terms. 21. Standard tariffs for smaller and renewable generators. 22. Consider Government guarantees behind NAWEC PPAs. 23. Greater public availability of information on Government, NAWEC and PURA websites. 24. Capacity building for the regulator and MoE to apply greater scrutiny to new proposals
Distorted incentives	• Tariffs are not cost reflective, particularly for the provincial systems.		25. Consider implementing more cost reflective tariffs, or a clearer system of cross subsidy that equalises the incentive on NAWEC to connect and provide reliable supply to all customers.
Debt availability	• Lack of lender confidence in Gambian assets as collateral. • High interest rates.	13. GEF-UNIDO grants for selected micro-grid systems	26. Consider soft loan schemes for generation projects, particularly renewable or off-grid projects.
Relatively high tariffs	• NAWEC cost structure unclear	14. NAWEC restructuring has been proposed for some time. All stakeholders (including NAWEC) seem positive about the plan. However, there is no definite progress. Previous attempts by GEG to make some management changes at NAWEC were unsuccessful	27. Full review of NAWEC operating practices. 28. Absolute need of separating water and electricity functions. Possible further separation of activities within the electricity sector in time. 29. More detailed reporting requirements for NAWEC on costs, at the same time as implementing a better accounting system in NAWEC.
Exposure to international fossil fuel prices	• Cost pass-through for fossil fuel is not fully equitable, with NAWEC receiving higher costs immediately, but being unable to pass them through to customers until annual price reviews		30. Consider system that allows a certain amount of price change (up or down) within a price control, up to certain agreed levels. 31. Consider use of other fuels with different cost drivers (renewables or coal). 32. Implement a "stabilisation fund" to cope with fuel price volatility
Encroachment on sites	• Problems on the existing Gamwind site due to people		33. Stronger management of exclusion zones, for both noise and general safety issues. A robust

Challenge	Description	Current activities and proposals (already underway or planned)	Additional actions required
	building in the exclusion zone around the turbine and subsequently suffering noise issues.		procedure should be in place to remove encroaching buildings, and to warn people not to build in those areas.
Commercial sustainability	• The power sector does not appear to be commercially sustainable (realised revenues do not meet costs), which is affecting investment and operation of the network and generators	15. Tariff review underway.	34. More effective system of pass through of costs to consumers 35. Develop / calculate a cost reflective tariff and a plan to achieve this tariff
Greater institutional independence for the regulator	• Government retains final control of most decisions, in particular, tariff reviews and PPAs.		36. Capacity building to allow the regulator to take on greater control. 37. Consider allowing the regulator to make final tariff decisions within certain annual percentage cap. 38. Consider giving regulator greater powers to audit and control power stations to ensure they comply with renewable requirements and/or Grid Code and licence requirements.
Lack of policy on use of waste biomass and energy crops	• Groundnut briquettes are a potential replacement for charcoal in domestic cooking. These briquettes could be used for electricity generation. However, with limited resources they may be better focussed on tackling deforestation. • Cashew and jatropha energy crops grow well in the Gambian climate. There are serious concerns about land use for food production and forestry.		39. Before significant waste biomass or energy crop development is planned, a detailed assessment on the impact on other targets should be made (forestry and food production). 40. Until such an analysis is made, we recommend that the Government should have an interim policy to prevent the use of biomass for electricity production.

4. ACTION PLAN

4.1. REQUIRED ACTIVITIES

A number of specific actions are necessary to enable the investment plan and wider strategic objectives to be delivered. In this proposed action plan we have focussed on activities over the next four years, which will put in place the framework needed for the 20 year investment plan to be delivered. Both the investment plan and this action plan should be reviewed each year to ensure that it remains on target and that the strategy is still appropriate to the developing situation.

These actions can be divided into the categories:

- Legal and institutional;
- Technical;
- Planning and Management;
- Capacity building; and
- Financial.

They are also linked to responsible parties in the table overleaf.

Table 9: Required actions

Steps required to improve investor confidence	#	Actions	Description of task	Responsible	Priority level	Notes
Commercial framework: Strengthen NAWEC: Improve and demonstrate the commercial viability of NAWEC to make them a trusted counterparty	1	Separate NAWEC activities in accounting terms	Separation of water and electricity functions and electricity sector activities (network, generation and retail supply activities) in accounting terms. Itemised costs of cross-subsides. Much of this information is already available from PURA tariff reviews, but is not currently published.	PURA	**HIGH**	Can be done immediately, as PURA have required information
	2	Tariff review process	The annual tariff review is effective, but changes within year are not reflected. The regulator is permitted within current guidelines to make final tariff decisions within certain annual percentage cap, based on changes to fuel prices. A clearer system of cross subsidy that equalises the incentive on NAWEC to connect and provide reliable supply to all customers (both rural and urban) would also be beneficial.	PURA	**HIGH**	Can be done quickly as current regulation allows some flexibility. If more significant changes to tariff review are required then might benefit from technical support of around EUR 175,000.
	3	Unbundling and operational efficiency of NAWEC	Full review of NAWEC operating and management practice to identify scope for greater efficiency. This should include consideration of the benefits (and possible negative impacts) of unbundling, and recommendations on the degree of unbundling advisable.	PURA with co-operation with NAWEC	-	Would benefit from technical support funded internationally, approx. EUR 750,000
	4	Procurement approach for NAWEC	Define a procurement strategy for fuel, generation and network investment that will minimise costs to current and future consumers. Competitive tender process for larger opportunities.	PURA and NAWEC	-	Would benefit from technical support funded internationally, approx. EUR 25,000
Commercial framework: Commercial framework to invest in conventional electricity generation	5	Adopt electricity strategy	Cabinet adopt the strategy.	Government (Ministry of Energy)	**HIGH**	Can be put in place immediately. Already drafted as part of this project
	6	Power Sector Investment Plan	Fully cost and assess the feasibility and environmental impacts of the preferred strategy set out in this study. This will include a feasibility study for generation, transmission and distribution requirements, identifying areas where it may be possible to attract private sector investment in a competitive and transparent way.	Government (Ministry of Energy)	**HIGH**	Would benefit from technical support funded internationally, approx. EUR 600,000
	7	Revise energy sector strategy	Update the strategy following the development of the power sector investment plan and of the procurement strategy	Government (Ministry of Energy)	-	Would benefit from technical support funded internationally, approx. EUR 150,000

Steps required to improve investor confidence	#	Actions	Description of task	Responsible	Priority level	Notes
	8	Ensure investment	Begin implementation of required investments (generation and transmission) following strategy for procurement, and where possible attracting private sector investment in a competitive and transparent way.	NAWEC	_	Keeping progress under review, and updating approach when appropriate.
Commercial framework: Commercial framework to invest in renewable electricity generation	9	Enact Renewable Energy Bill	Adoption of the draft Bill by Parliament	Government (with support from Ministry of Energy)	**HIGH**	Can be put in place immediately. Already drafted as part of this project
	10	Adopt feed in tariffs and simplified PPAs	Adoption of the draft FIT rules and standard PPA by PURA with approval by Cabinet	PURA (with approval by Cabinet)	**HIGH**	Can be put in place immediately. Already drafted as part of this project
	11	Tendering system for renewable grant funding	Process for tendering for grants and reducing FIT costs to consumers, as proposed as part of the RE Law and FIT Rules	International agencies (Government funding constrained)	_	Would benefit from technical support funded internationally, approx. EUR 600,000
	12	Simplify and strengthen permitting	As required by the draft law, the various agencies should co-ordinate to ensure the permitting process for renewable energy projects is as simple as possible and appropriate for the project scale.	Cross departmental (led by MOE)	_	Would benefit from technical support funded internationally, approx. EUR 150,000
	13	Introduce credit lines for renewable energy and energy efficiency	Introduce soft loan schemes or other credit line facilities for generation projects, particularly renewable or off-grid projects, and for energy efficiency. Consider including capacity building and project handover provisions similar to those used in successful community forestry scheme. Adopt lessons learned from GEF UNIDO projects.	International agencies (Government funding constrained)	_	Would benefit from technical support funded internationally, approx. EUR 400,000
	14	Evaluation of renewable resources	More accurately assess the country's natural renewable energy resources to give evidence to investors on the best locations to site their plants. Building on the Lahmeyer study.	Government (Ministry of Energy and department of Water Resource)	_	Would benefit from technical support funded internationally, approx. EUR 400,000
	15	Biomass and energy crop impact assessment	A detailed assessment of the impact of biomass use in power generation on other targets should be made (forestry and food production).	Government (Ministry of Energy)	_	Would benefit from technical support funded internationally, EUR 300,000 for impact assessment and EUR 150,000 for strategy
Commercial framework: Commercial framework to invest in rural electrification	16	Rural electrification strategy and plan	Show where the grid (including provincial systems) is expected to reach over time. Set out the approaches, funding requirements and institutional requirements for ongrid and offgrid investment based on a detailed analysis of what is feasible. (Linked to Power Sector	Government (Ministry of Energy)	_	May interact with Power Sector Investment Plan

Steps required to improve investor confidence	#	Actions	Description of task	Responsible	Priority level	Notes
			Investment Plan)			
Commercial framework: Other commercial framework activities	17	Accessibility of information	Greater public availability of information on Government, NAWEC and PURA websites. To include: studies on resource availability, processes for obtaining land and connections for generators, Government policy and contact details for more information.	Government, PURA and NAWEC	-	Can begin immediately, with each of the actors reviewing information they make available.
Commercial framework: Controllability and reliability of the network to ensure a stable market for power.	18	Regional interconnection	Prioritising regional interconnection and power development at inter-Governmental level. Consider alternative regional plans (such as with Senegal) in case OMVG does not proceed.	Government (supported by Ministry of Energy)	-	If this deviates from work already planned under OMVG/WAPP, then could benefit from technical support to assess new alternatives, approx. EUR 200,000
	19	Improving NAWEC reporting on network reliability	More detailed reporting requirements from NAWEC on based on reliability (for example, customer minutes lost), hourly load/generation profiles, with the objective of ultimately introducing a performance incentive. May include requirements for greater network metering and improved accounting systems.	NAWEC, assessed by PURA	-	Would benefit from technical support funded internationally, cost of support approx. EUR 150,000
	20	Load flow model	Load flow model for NAWEC to assess grid, including training in the use and interpretation of the model for both NAWEC and PURA. Will support loss evaluation and connection of generation plants (renewable and conventional) by allowing better understanding of the network. Training for PURA will allow them to better evaluate and understand NAWEC decisions, so they can review them when necessary as external arbitrator.	NAWEC	**HIGH**	Would benefit from technical support funded internationally, cost of support approx. EUR 500,000
	21	Full technical study to enable central control of the electricity grid	Full technical study of the requirements for balancing and control of the electricity grid. This is likely to include a central control system, remote controllability for certain generators (and controllable demand) to allow them to be dispatched up or down in response to changes in demand or variable generation, and appropriate real time metering on the network and for large generators or demand.	NAWEC	-	Would benefit from technical support funded internationally, cost of support approx. EUR 500,000
	22	Central Control System	Implementation of control and dispatching centre to facilitate more reliable supply and incorporation of more variable renewable generation.	NAWEC	-	Dependent on outcome of technical study (21)

Steps required to improve investor confidence	#	Actions	Description of task	Responsible	Priority level	Notes
	23	Balancing services	Review PPAs for controllable plants as they come up for renewal. Provide incentives for flexibility and controllability in PPAs for controllable plant, potentially an obligation for supplying certain ancillary services and/or the formula to pay for the ancillary services in a transparent manner. Define a process for balancing, including roles and responsibilities. Consider making simple PPAs accessible to generators (including smaller onsite back-up generators), and offering favourable tariffs to certain demand that can be constrained down.	NAWEC (monitored by PURA)	-	Dependent on outcome of technical study (21), and would benefit from technical support funded internationally, cost of support approx. EUR 50,000
	24	Grid Code	Grid Code requiring certain performance standards to be met by generators and NAWEC. Potentially enforced through licences. Co-ordinate to ensure ultimate compatibility with WAPP. Giving the regulator greater powers to audit power stations to ensure they comply with Grid Code and licence requirements.	PURA	-	Requires regional co-ordination to ensure compatibility with WAPP, and would benefit from technical support funded internationally, cost of support approx. EUR 100,000
Efficiency: Improve efficiency so that electricity is used rationally	25	Loss identification and management	Introduce accurate system metering to identify where technical and non-technical losses are occurring, so that mitigating action can be taken. Will also allow better understanding of generation/demand profiles. Loss reduction plan made and implemented, building on success achieved by NAWEC in recent years (reduction from 30% to nearer 22%).	NAWEC	**HIGH**	Would benefit from technical support funded internationally, around EUR 450,000
	26	Energy efficiency awareness raising	Publicity campaign to raise awareness of energy efficiency and simple steps people can take. This could include incorporating energy efficiency and renewable energy awareness courses in the curriculums of schools.	Ministry of Energy	-	Would benefit from technical support funded internationally
	27	Energy efficiency strategy	Develop a fuller energy efficiency strategy. Options could include an energy audit program, technical standards and labelling requirements.	Ministry of Energy, NEA, NAWEC and PURA	-	Would benefit from technical support funded internationally, EUR 500,000
Commercial framework: Capacity building to ensure an adequate workforce and good governance	28	Capacity building in competitive procurement and tendering	Capacity building for PURA and MoE to apply greater scrutiny to new proposals, including training in tender processes and other potential procurement strategies and financial and technical evaluation of tenders.	Ministry of Energy and PURA	-	Would benefit from technical support funded internationally EUR 50,000
	29	Capacity building plan	In particular for technicians and engineers in the power sector, also management and financial requirements	Government (cross departmental, led by MOE)	-	Would benefit from technical support funded internationally EUR 50,000
	30	Implement training plan				EUR 200,000

4.2. *KEY ACTIVITIES*

4.2.1. RENEWABLE ENERGY FRAMEWORK

Recommendations for renewable energy support will be the next component of this project. Many of the fundamental principles have been established, including the need to minimise any cost impact on electricity consumers, who already struggle to pay existing tariffs. Therefore renewable projects are expected to be supported to the level established by the least cost plan, unless additional funding sources can be identified (see section 4.4.2).

The reports on the renewable energy law and feed in tariffs prepared under the framework of this technical assistance provide details on how this support can best be provided.

In the longer term, a more detailed assessment of the renewable energy resources (building on Lahmeyer) may make it easier for renewable energy projects to proceed.

4.2.1. ENERGY EFFICIENCY

Energy efficiency is important as it allows the Gambia to increase access to electricity in a more rational and efficient way.

Specific targets for efficiency in the near term may be challenging in a country where true electricity demand cannot be known. It is to be expected that demand will grow because of improvement in access, even if there is improvement in efficiency. A more pragmatic approach would be to systematically adopt policies that will help to boost energy efficiency.

Prepayment meters already provide a very immediate feedback to consumers on their level of usage, and the price of electricity provides a real incentive to consumers to adopt efficiency measures. This means that the first barrier to improving efficiency is already removed.

Other barriers, like the awareness and capital cost of energy efficiency measures, should be addressed. There are a number of steps that can be used to incentivise efficiency

Near term policies suggested can include:

- **Raising awareness of options:** Government websites and publicity messages can tell consumers about energy efficiency options and raise awareness. The Government should consider a public awareness campaigns. This could include incorporating energy efficiency and renewable energy awareness courses in the curriculums of schools.
- **Credit lines or grant schemes:** Similar schemes to those proposed for renewable electricity could be set up for energy efficiency, removing the financing barrier to energy efficiency. These could help to finance solar water heaters and more efficient street lighting.

Longer term options might include:

- Imposing an energy audit program in the Government, industrial and commercial sectors within present energy consumption standards.
- Establishing a laboratory for examining electrical equipment in a manner that serves local market needs.
- The Government can consider introducing technical standards and labelling requirements for electrical products, for example air conditioners, light bulbs and televisions. For example, adopting a national energy efficiency sticker on locally produced or imported energy technologies.
- Setting minimum technical standards for efficiency, and preventing sale of products that do not meet those standards.

Key participants in developing an approach to energy efficiency are likely to be the Ministry of Energy and NEA, as well as potentially PURA.

4.2.2. STABILISATION FUND

The concept of a stabilisation fund to avoid the impacts of oil price spikes has been used in different international contexts. For example, this type of fund has been used in countries which are net importers of oil products to avoid transferring international price spikes to consumers, or to avoid undesired financial impacts in the oil producing company. In countries where there is a wholesale electricity market, the fund is used to insulate retail suppliers/distribution companies from some degree of market price spikes.

The fund typically operates following these principles:

1. There is an initial provision, generally from the government, of a certain amount of money;

2. This funds are deposited in a bank like the central bank or a special account;

3. There is an average price estimate of imported goods (in case of a fund to cover oil price spikes) or the average market price of electricity;

4. When the actual price is lower than the estimated price, the difference between actual price and estimated price is deposited in the fund and the final price to consumer is maintained; and

5. Conversely, when the actual price is higher than the estimated price, the company selling the good or service maintains the final price to consumer and covers the difference with contributions from the fund.

The operation of the fund requires specific rules to guarantee transparency and to guarantee that these resources are not used for any other thing than covering price spikes.

Where a fund is being used to mitigate international oil price spikes for power generation the following aspects have to be taken into account:

1. It is necessary to feed this fund with an initial provision. This can be directly from the government or alternatively funded through higher tariffs than needed by the utility.

2. The bank to be used and the rules to use the fund have to be clearly set beforehand and allow an automatic use of this fund.

3. A reference price of oil products has to be set initially; this will be the price above which or under which the fund will be used.

4. The difference between the reference price and the actual price has to be fairly demonstrated and approved by an authority, such as the regulatory authority. It is advisable to use international prices as indicators, to avoid cases where the utility makes "poor" purchasing decisions. An alternative way to demonstrate the purchasing price is to buy through tenders, when it is possible (this does not apply in the Gambia, where there is a single importer).

5. Adjustments or use of the fund (either to contribute to or source from) have to be clearly established beforehand, for example every month or every two months there will be a calculation to assess how much the company has to pay to the fund or receive from the fund.

6. A certain level of the fund has to be set (set a "flag") beforehand in case there has been an extensive use of the fund in order to be aware before it is totally consumed and therefore take special actions.

7. Regular audits and reporting obligations have to be set when creating the fund to ensure transparency.

Following the workshop, it was felt that this option was not likely to be feasible in practice. The Government is not able to put aside sufficient cash for such purposes. In a country where there are significant financial challenges, it was not felt that a pot of money could practically be set aside.

However, this can be achieved (though in a slower manner) by the company itself setting aside a small quantity of money from their revenues from tariff.

4.2.1. ENSURING ELECTRIFICATION

The demand assumptions assume significant electrification of the Gambia. For this to be achieved in reality, it may be necessary to reduce barriers to connection. This may include reducing or eliminating the cost to connect, which (although low in an international context) is currently a barrier for many Gambians.

Furthermore, a rural electrification strategy will be important to ensure that rural areas needs are met in advance of wider grid expansion.

4.2.2. INTERNATIONAL CONTEXT

Interconnection with neighbouring Senegal offers an opportunity to share resources and balance over a wider system. The OMVG project is the most immediate opportunity to establish this interconnection at a regional level. Once interconnection is in place, larger plant like coal become technically feasible for the Gambia. Any excess power from the coal plant can be sold over the border, and if the plant is unavailable balancing power may be purchased from Senegal.

Even if the OMVG project does not go ahead, interconnection with neighbouring countries would still be worth considering and discussing, as it would allow bigger modules of traditional generation and support in emergencies.

4.2.3. TESTING THE STRATEGY

The study of least cost alternatives has necessarily been high level. It will be important to test the technical suitability of the approach from a technical viewpoint. Detailed power sector investment planning will be required on a next stage once a general strategy has been adopted. These may help to flesh out the detail of investment requirements and also to "package" investments into forms that may be attractive to international investors.

Biomass use (in the form of waste biomass or energy crops) has been a divisive issue in the Gambia, with proponents on both sides of the debate. It is appropriate to thoroughly review the suitability of biomass from a variety of sources in the context of wider sustainability issues like alternative land use for agriculture and forestry, and alternative waste biomass use for cooking fuel. This is discussed in more detail in the report on the draft renewable energy law.

It will be essential to review and update the "next steps" both once the power sector investment plan and biomass study is complete. In fact, it is advisable to review this strategy regularly (potentially annually) to ensure it remains the least cost option and fully aligned with the political, economic and social objectives for the power sector. These reviews can take into account the changing international context of WAPP development and the OMVG project. They can also reflect developing fuel prices, improved information on the network and demand, and developing technology costs and performance.

4.2.4. COMMERCIAL SUSTAINABILITY

One of the key barriers to delivering investment is finance. Private sector investors and IFIs need the confidence to invest, and NAWEC needs to be able to raise finance.

This requires a clear commercial framework, so that investors and NAWEC have clear foresight of potential revenues (and these cover costs and allow a reasonable return on investment). This would include revisiting the tariff review process to allow some flexibility for tariff reviews (up or down) within year, subject to a cap and collar. It is also important to make cross-subsidies more transparent.

Technical and non-technical losses cannot be managed when they are not accurately measured and monitored. A loss management strategy, including measuring true technical losses, is required. Balancing and control of the network also needs improving, to reduce load shedding and improve power quality. NAWEC cannot achieve their full revenue potential if they cannot get power to customers that want it.

A load flow model is necessary for NAWEC to properly assess the grid. This would support loss evaluation and connection of generation plants (renewable and conventional) by allowing better understanding of the network.

Other steps to increase reliability include establishing a Grid Code, introducing a requirement for ancillary services for conventional generators and implementing a central control system. A stable and reliable grid has three benefits: firstly, the Gambia will need to meet minimum standards to connect to the WAPP; secondly, greater stability would reduce load shedding and increase consumer confidence, supporting demand for power; and finally, good stability and controllability is essential to allow higher penetrations of renewable electricity.

PURA will need to challenge NAWEC and ensure that they and other industry players are delivering value for money. Reviewing the management and accounting structure of NAWEC, so that costs are more easily seen and controlled will be an essential step in ensuring it can be robustly and fairly regulated. An important part of this process will be the unbundling of accounts for water and power within NAWEC.

Private investors need good foresight of their potential revenues to invest. This is likely to include a simple PPA for renewable generators. It will also include defining a procurement strategy for conventional generation (coal and oil-fired).

Information needs to be more available to potential investors. At present the public availability of information through websites is limited, even when in theory it should be publically available. An ongoing programme to improve the availability of information is required. In parallel, missions to attract private sector investment may be beneficial, providing information and contacts to potential national and international investors.

4.2.1. GOVERNANCE

A point that has been highlighted by multiple stakeholders over the course of this project is the importance of governance. Without good governance, both IFIs and private sector companies will be

very concerned about investing in the Gambia. Investors and IFIs need to see clearly defined separation of policy (determined by Government), regulation (led by PURA) and commercial activities (NAWEC and private investors).

Clear policy setting is required to allow investor certainty: this may include a biomass and energy crop strategy and a target for renewable electricity.

A clear cross subsidy and incentive framework would allow Government to influence the direction of the electricity sector, without having to take a direct role in all investment decisions. For example, giving NAWEC a clear financial incentive to connect rural customers should ensure that direct political influence would not be required to ensure that policy goals are achieved. This would include delegating greater authority to PURA to make more final regulatory decisions, while still following the policy framework set by Government.

It will be important to clarify the cost base in NAWEC. This would include a full review and restructuring of NAWEC to improve NAWEC reporting. At present, it is unclear to what extent NAWEC has cross subsidies between electricity and water, and how the various costs break down in the electricity sector. Clear accounting separation and comparison to international and wider African standards will enable better targeting of efforts to reduce costs in the power sector. This will also help PURA to challenge NAWEC and ensure that they and other industry players are delivering value for money.

4.2.1. CAPACITY BUILDING AND AWARENESS RAISING

Capacity-building activities and training programs are essential to develop a national industry. It will be important to establish contact with international agencies and other countries which have developed these technologies and will monitor the development of standards and codes for power system installations.

The university and schools will play a key role in continuously working with government and private sector to deliver capacity building and training activities at several levels:

- At the academic level with the development of master programs and the training of engineers, designers, etc.,
- At the professional level, with their support in the capacity building activities for professionals (installers, etc.), and
- At the grassroots level, with their support in awareness campaigns.

Furthermore, capacity building at the management, regulatory and procurement level will be important for MOE, NAWEC and PURA, as they lead and manage the transition to a fit-for-purpose power system.

Information needs to be more available to potential investors. At present the public availability of information through websites is limited, even when in theory it should be publically available. An ongoing programme to improve the availability of information is required.

In parallel, missions to attract private sector investment may be beneficial, providing information and contacts to potential national and international investors.

4.3. TIMELINE

These actions have been set to approximate timescales in the following table.

Table 10: Action plan

#	Actions	2013 Q1	Q2	Q3	Q4	2014 Q1	Q2	Q3	Q4	2015 Q1	Q2	Q3	Q4	2016 Q1	Q2	Q3	Q4	2017 Q1	Q2	Q3	Q4
1	Separate NAWEC activities in accounting terms	██	██																		
2	Improve tariff review process	██	██	██																	
3	NAWEC unbuddling and operational efficiency					Plan and procure	Deliver														
4	Procurement approach for NAWEC					Plan and procure															
5	Adopt electricity strategy	██																			
6	Power Sector Investment Plan					Procure	Deliver														
7	Finalise energy sector strategy																				
8	Ensure investment																				
9	Enact Renewable Energy Bill	██	██																		
10	Adopt feed in tariffs and simplified PPAs	██	██																		
11	Tendering for grant funding					Procure	Deliver														
12	Simplify and strengthen permitting																				
13	Introduce credit lines for renewables and energy					Procure	Deliver														
14	Evaluation of renewable resources					Procure	Deliver														
15	Biomass and energy crop impact assessment					Procure	Deliver														
16	Rural electrification strategy					Procure	Deliver														
17	Accessibility of information					Ongoing review															
18	Regional interconnection	Ongoing regional engagement																			
19	Improving NAWEC reporting on reliability						Procure	Deliver													
20	Load flow model					Procure	Deliver														
21	Technical study to enable better network control	Procure	Deliver																		
22	Central Control System							Procure	Deliver												
23	Balancing services							Procure	Deliver												
24	Grid Code							Procure	Deliver												
25	Loss identification and management plan					Procure	Deliver														
26	Energy efficiency awareness raising					Procure	Deliver														
27	Energy efficiency strategy					Procure	Deliver														
28	Capacity building in procurement					Procure	Deliver														
29	Capacity building plan					Procure	Deliver														
30	Implement training plan																				

4.4. IMPLEMENTATION AND MONITORING PROCESS

The Ministry of Energy to lead all the different actions and sub-projects and also gather support from international donors (national agencies, multilateral funding, etc.)

Both monitoring and reporting will be critical, to assess the efficiency of the actions and the fulfilment of the targets and also to give feedback to the international donors and private investors. In fact, the progress towards the accomplishment of the different targets and activities outlined in the Action Plan should be evaluated each year to assess their degree of completion. At the same time this strategy might be reviewed with worldwide technological developments in this sector and the emergence of further electricity options for the Gambia.

In addition to the current (and ongoing) reporting and monitoring requirements of electricity generation facilities, any electricity generators receiving support under the programme should be part of a continuous program of monitoring, involving the relevant stakeholders from private and public institutions will be aligned with the successful implementation of the strategy.

This strategy will be evaluated in the midterm (every year) to assess the degree of compliance and the progress of the different activities and measures included in the framework, and to check the overall direction of the strategy remains the best (least cost and lowest risk) option for the Gambian power sector. The Strategy and regulations will be updated if amendments are required.

4.4.1. IMPLEMENTATION PROCESS

The Ministry of Energy, working with the Ministry of Justice, will be responsible for the overall implementation and evaluation of the regulatory framework. PURA will work alongside, and will have a particularly important role in carrying out the monitoring process of the development in the energy sector and will use several indicators to assess the effectiveness and progress of the initiatives.

The key parts in the implementation of this Strategy and their main responsibilities are summarised in Table 9.

The Ministry of Energy will lead and facilitate the implementation of the Electricity Strategy, in collaboration with PURA, NAWEC, private sector and NGOs. The flagship activities to be developed by the Ministry include:

- Ensuring a robust and commercially sustainable basis for the power sector, through NAWEC reform and a review of tariff arrangements.
- Establishing a stable and competitive framework for private sector investment.
- Putting in place initiatives for the improvement of the electricity network and lay down standards for the quality of electricity supply.
- Fostering the technical and management capability of the industry.
- Developing the understanding of the interactions between the development of the power sector and other aspects of economic and social development.

- If funds can be obtained, establishing and managing a fund to finance the development of renewable energy and energy efficiency activities and promotion campaigns, encouraging the participation of the private sector.

The Ministry might be assisted by international consultants when required, whose role will be the technical backstopping services, in order to support them in:

- Technical feasibility studies,
- Regulatory development on network management and quality of service,
- Managing credit lines and funds,
- Procurement procedures,
- NAWEC restructuring.
- Design, implementation, and monitoring of projects,
- Capacity building, and
- Awareness raising.

The review and modification of the existing regulatory framework towards the achievements of these strategy targets is the key role of this body. It will also be responsible for evaluating the required support for the different technologies and the submission of them to the Government for its approval.

The Ministry of Energy could choose to establish a **programme management unit** within the Ministry to take ownership of the electricity strategy and action plan. This would help give prominence and leadership to delivering on the action plan.

4.4.2. FUNDING THE ACTION PLAN

So far, the development of the power sector has been inhibited financially by factors such as high initial costs, high costs of private lending, the commercial sustainability of NAWEC, and financial and technical performance risks. There is also not a fully transparent framework for private sector investment.

Commonly, renewable energy technologies are supported by a premium on electricity tariffs. However, for the Gambia it is not deemed appropriate to introduce a surcharge in electricity tariffs. Given the low level of demand and reasonable targets for the penetration of renewable technologies and the additional costs expected by these technologies, the surcharge required to support these facilities in the transformation phase is not very significant. However, poverty reduction is an important goal for the Gambia, and electricity tariffs are already seen as unaffordable by many.

Therefore, the development of a robust regulatory framework, preliminary technical studies and demonstration projects, and any capital grant or credit line support, may require additional funds.

The use of additional funding sources will be important until the willingness to pay matches with the project costs and the maturity of the technology, and the rate of electrification, means that the cost is able to be totally financed through the surcharge in end-consumers' electricity tariff. Financial support from International Financing Institutions (IFIs) which have facilities to provide debt/equity for the purpose of supporting private sector projects with clear development impacts in the infrastructure sector, will enhance and promote the settlement of an enabling environment to attract private developers. The GEF-UNIDO project has already begun to put in place essential demonstration projects and technical studies for relatively complex technologies, such as solar and wind. A permanent process of monitoring, training and management of the projects developed during the demonstration phase will ease the development of these technologies and hasten the shift into the transformation phase.

Ministry may create an "umbrella programme", where all the financing needs will be clustered into "packages" that international donors (National Cooperation Agencies, Multilateral entities, etc.) could finance according to their vision and objectives. Among other objectives, this can provide the Fund for described in the Feed in Tariff Report as a mechanism to help leverage the feed in tariff.

4.4.3. MONITORING AND EVALUATION

The Ministry of Energy, has the ultimate responsibility for monitoring and evaluating the implementation of this Strategy based on the guidelines provided by Government. For this purpose a set of indicators is proposed in order to ensure the strategy is achieved during the expected time period.

The assessment's results regarding these indicators, as well as the recommendations obtained from this analysis, will be published in an annual report which will be submitted to Government.

Monitoring will be useful for both the public sector (to evaluate the current implementation of the programme) and also the private sector (to develop their participation through investment, direct involvement, etc.)

The tentative indicators for the annual assessment of the performance of this strategy over the period 2013-2020 might be:

- Number and duration of customer outages.
- Number of deviations of voltage and frequency from national standards.
- Growth of installed MW by technology.
- Level of connection to neighbouring countries.
- Number of Gambian nationals that are trained operators involved in designing, supplying, installing and maintaining power installations.
- Contribution of the power sector to GDP.
- For renewables specifically:
  - Percentage of energy from renewable energy sources in the energy supply mix.
  - GWh of electricity generated from renewable sources.
  - Estimate of the avoided carbon emissions from renewable energy.

ANNEX 1: MODEL OVERVIEW

1. APPROACH

We used our own ORDENA plus® optimisation model to develop the energy scenarios. This is a well-tested and comprehensive fully integrated dynamic electricity production costing and long-term investment planning model that has been used internationally in many power systems. For The Gambia, the model goal is to minimize investment and production costs over the next 20 years, by choosing the optimal volume and timing of generation capacity and transmission network investments in order to satisfy expected demand growth, capacity retirement and increasing penetrations of renewable generation. There is also a need to achieve national electrification targets. Demand growth will include increases in existing electrified regions (greater Banjul and the provincial systems) and electrification of previously unconnected zones.

The base year for modelling was 2010, as it was the last year for which information was available.

Outputs from the model will include (but not limited to):

- Optimal generation expansion plan;

- Optimal transmission expansion plan;

- Per year total system costs (investment + operational fixed + operational variable); and

- Volume of supplied and unsupplied energy per "zone".

2. TECHNICAL DESCRIPTION

The model is a mixed-integer mathematical program written in Mosel and solved using the FICO™ Xpress-Optimizer. Depending on the application, the model time-step is chosen as daily though to yearly (in this case we use yearly 2012-32).

The objective is to minimize the present value of total system costs (e.g., $) across entire time horizon (T). Total system costs include investment costs (annualized across the candidate asset amortization period) plus expected operation cost, composed of fuel cost and variable O&M, plus the cost of supply reliability constraints, plus the cost of unserved energy, plus or minus the effects of externalities (e.g., environmental aspects).

This can be expressed mathematically as minimising:

$$\sum_{t=1}^{T}([total\ variable\ costs]_t + [total\ fixed\ costs]_t)/(1+r)^t \quad (1)$$

Where *r* is the costs of capital expressed in real terms.

Total variable costs for year t comprise of:

- Fuel costs

- Operation and maintenance (O&M) variable costs

- Unserved energy costs

Total fixed costs for year *t* comprise of:

- Investment costs

- Operation and maintenance fixed costs

The time series of demand is transformed to a load-duration curve that can be defined at monthly, quarterly, seasonally or yearly level. A load duration curve is necessary for each transmission system node. This is described in the following figure.

Figure 44: Electrical demand characterisation
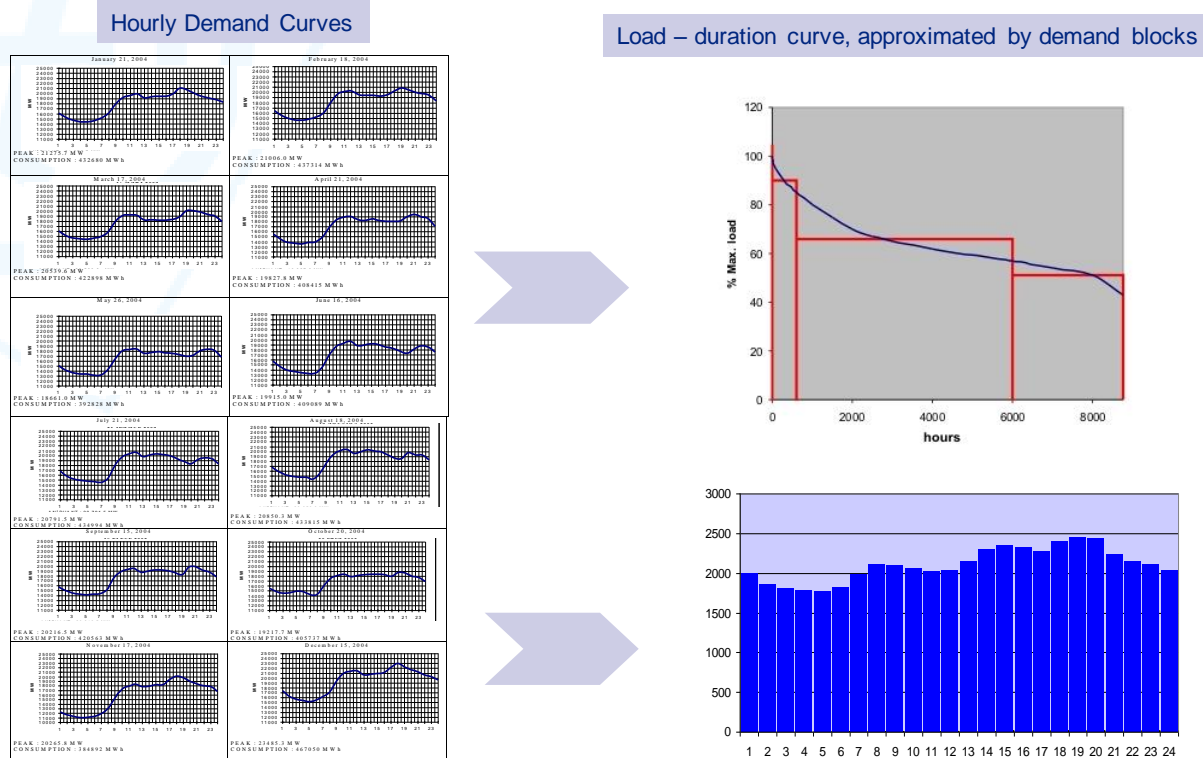
The transmission network is represented within the model using a simplified network model that fulfils Kirchhoff's 1st Law. Maximum capacity per line, area protection contingencies (e.g., N-1 security) and must run generation can all be represented. Losses can be represented using a piece-wise linear approximation. For this application we propose to develop a representation of The Gambia 33kV transmission network that captures the key lines and intra-regional connections of interest. Grid connection costs will be an input to the model. We will not include a representation of the distribution network and demand will be modelled at high voltage (i.e., 33kV and above) grid supply point level. The details of this and other key input assumptions are outlined in the next Annex.

2.1. SUPPLY RELIABILITY

ORDENA plus® has been developed to identify suitable investment strategies in response to demand growth and capacity retirement in a power system where increases in renewable generation and security of supply is of primary concern. For instance, the objective in equation (1) to minimize total system costs whilst meeting demand requirements may be accompanied by a constraint to meet some pre-set level of security of supply risk. The advantage of this approach is that the cost of meeting the target level of security of supply risk can be assessed in addition to any other constraints (e.g., annual renewables production targets) that are modelled.

Supply reliability constraints can be captured through the cost of unserved load (e.g., $/MWh) or the need to have a reserve margin.

Given the lack of full electrification in The Gambia, there will be a large volume of unserved load in the early years as there is inadequate generation and transmission capacity to meet total theoretical demand. Therefore reserve margins could not be met and a cost of lost load is a more appropriate representation.

The cost of unserved energy is always theoretical. In the Gambia, this is likely to be lower relative to power systems with full electrification). For example, in European or U.S. models there is a high cost of unserved load, typically $10,000/MWh+. Setting the costs of unserved load at a mark-up on tariff level will allow the model to "shed" some demand in the first years of the simulation and avoid an unrealistic boom in investment.

The model also has a number of optional constraints including, for example, target reserve margin, annual emissions limits, fuel use limits, (e.g., gas imports, technology investment limits), and renewable generation targets.

3. ECONOMIC DECISIONS WITHIN THE MODEL

The model has an objective to meet demand in the least cost way over the time frame modelled. In this case this will be the period 2010-2032. 2010-2012 are historic periods, and therefore no new

assets are available to be built over that period. They are used to calibrate the model and establish the current position.

The model will start with a representation of the existing and planned network (described in Section IV 1.1 and 1.2) and generation (described in Section IV 3.1 and 3.2).

It will start with a representation of current met demand. Over time this will increase to reflect greater access to and use of electricity. The demand growth selected is described in Section IV 2.

The model will have the option to build new network (described in Section IV 1.3) and different types of generation (described in Section IV 3.3), or supply an isolated demand with isolated generation instead of building the line to connect it to the main grid, or at the limit to choose not to meet demand.

The choice of building network and/or generation is based on the economic balance over the lifetime of the asset. Therefore it includes both the build cost and the operational cost of the assets. At all nodes, the model will have the choice to build new small generation close to the demand, or to connect the demand to the main transmission system and to larger generators.

For example, a currently unsupplied rural node may start off being supplied by a small LFO generator. Over time, the demand in the node may become large enough to justify connection to the main transmission system. This is equivalent to representing a microgrid growing over time and then being absorbed into the main system and potentially lower cost power.

The opportunity cost of not meeting demand in the model is priced at the value of lost load (described in Section IV 2.4). In some circumstances the model may choose not to meet all of the peak demand, i.e., when the production cost is higher than the value of lost load. This is a classic issue in economics; it is not economical to supply demand for a product when the cost of production is greater than the value the consumer places on it.

ANNEX 2: BASELINE INPUTS

1. TRANSMISSION NETWORK

Within the model we use a simplified representation of the transmission network, as information required for a full representation is not currently available. The simplified network representation requires voltage and losses from node to node (location).

Figure 45 shows the approximate geographic locations of the nodes that we will use. The nodes were chosen to represent the existing network as closely as possible and add a representation of unconnected demand further from the existing network. Specifically:

- All existing and planned substations in the Greater Banjul area are represented as nodes;
- Generation and demand are represented for the provincial systems (where less detailed information is available); and
- Representative points have been chosen as a simplified representation of unconnected demand outside the existing system. There is one or more of these points in each of the local government areas.

The transmission network has existing connections and potential for new connections.

The connections in the existing transmission system, any planned new connections and options for new expansions are summarised in Figure 45.

33kV lines cost approximately $28,000/km (with additional costs for substation and civil works etc.), according to the NEPCO report.

132kV lines are assumed to be US$433,000/km, based on international standard costs.

O&M for the transmission system is assumed to be 2% of transmission capital costs for 132kV lines and 5% for 33kV lines, in accordance with the NEPCO report.

Technical parameters for existing planned and candidate lines are outlined in Table 11.

1.1. TRANSMISSION LOSSES

At present it is not possible to accurately separate the technical and non-technical losses on the transmission system in the Gambia. This means that the overall losses figure of 30-35% does not indicate the actual losses on transmission line. We therefore assume a uniform losses figure of 5%. It is important for the future that metering on the network is improved, so that losses can be properly understood and controlled.

Figure 45: Connections of nodes (not to scale)
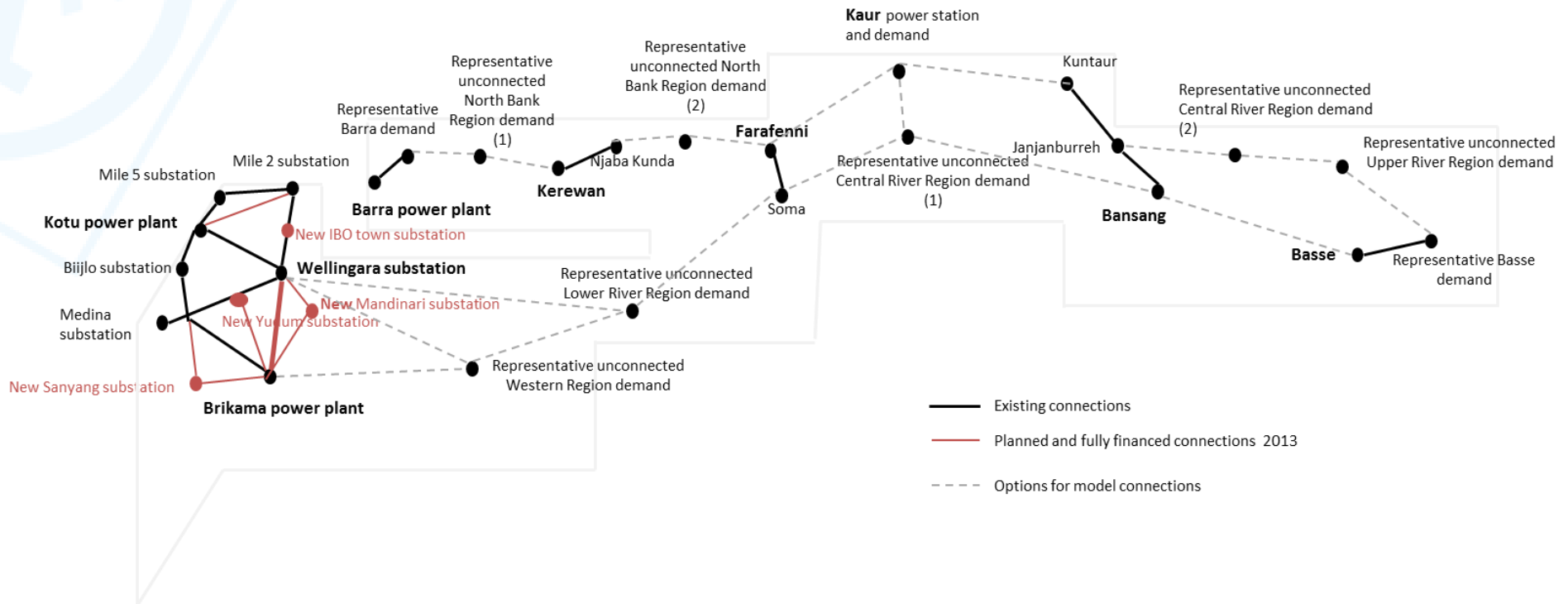
Source: AF-Mercados

Table 11: Detail of modelled transmission lines

From Node	To Node	Status	Losses	Year first available	CAPEX (US$/MW)	Fixed O&M cost (US$/MW year)	Amortization time	Voltage (kV)	Construction time (years)	km	Capacity (MW)
Kotu	Bijilo	Existing	0.05	-	0	422	20	33	-	5	16.6
Kotu	Wellingara	Existing	0.05	-	0	675	20	33	-	8	16.6
Kotu	Mile5	Existing	0.05	-	0	675	20	33	-	8	16.6
Mile5	Mile2	Existing	0.05	-	0	253	20	33	-	3	16.6
Mile2	Wellingara	Existing	0.05	-	0	1265	20	33	-	15	16.6
Wellingara	Medina	Existing	0.05	-	0	1012	20	33	-	12	16.6
Medina	Brikama	Existing	0.05	-	0	928	20	33	-	11	16.6
Medina	Bijilo	Existing	0.05	-	0	928	20	33	-	11	16.6
Barra	BarraDemand	Existing	0.05	-	0	422	20	33	-	5	16.6
Kerewan	NjabaKunda	Existing	0.05	-	0	1687	20	33	-	20	16.6
Farrafenni	Soma	Existing	0.05	-	0	1349	20	33	-	16	16.6
Kuntaur	Janjanburreh	Existing	0.05	-	0	1687	20	33	-	20	16.6
Janjanburreh	Bansang	Existing	0.05	-	0	1687	20	33	-	20	16.6
Basse	BasseDemand	Existing	0.05	-	0	3373	20	33	-	40	16.6
Brikama	Wellingara	Planned	0.05	2013	0	1321	40	132	1	18	118
Mandinari	Wellingara	Planned	0.05	2013	0	928	20	33	1	11	16.6
Eboe	Wellingara	Planned	0.05	2013	0	675	20	33	1	8	16.6
Wellingara	Yundum	Planned	0.05	2013	0	422	20	33	1	5	16.6
Mile2	Kotu	Planned	0.05	2013	0	928	20	33	1	11	16.6
Mile2	Eboe	Planned	0.05	2013	0	590	20	33	1	7	16.6
Bijilo	Sanyang	Planned	0.05	2013	0	2024	20	33	1	24	16.6

Sanyang	Brikama	Planned	0.05	2013	0	1096	20	33	1	13	16.6
Yundum	Brikama	Planned	0.05	2013	0	759	20	33	1	9	16.6
Brikama	Mandinari	Planned	0.05	2013	0	1181	20	33	1	14	16.6
Kotu	Mile5	Candidate	0.05	2015	29356	587	40	132	2	8	118
Mile5	Kotu	Candidate	0.05	2015	13494	675	20	33	2	8	16.6
Kotu	Mile2	Candidate	0.05	2015	40364	807	40	132	2	11	118
Kotu	Bijilo	Candidate	0.05	2015	8434	422	20	33	2	5	16.6
Kotu	Bijilo	Candidate	0.05	2015	18347	367	40	132	2	5	118
Brikama	Bijilo	Candidate	0.05	2015	37108	1855	20	33	2	22	16.6
Bijilo	Brikama	Candidate	0.05	2015	80729	1615	40	132	2	22	118
Bijilo	Sanyang	Candidate	0.05	2015	40482	2024	20	33	2	24	16.6
Bijilo	Sanyang	Candidate	0.05	2015	88068	1761	40	132	2	24	118
Sanyang	Brikama	Candidate	0.05	2015	21928	1096	20	33	2	13	16.6
Sanyang	Brikama	Candidate	0.05	2015	47703	954	40	132	2	13	118
Yundum	Wellingara	Candidate	0.05	2015	8434	422	20	33	2	5	16.6
Yundum	Wellingara	Candidate	0.05	2015	18347	367	40	132	2	5	118
Yundum	Medina	Candidate	0.05	2015	13494	675	20	33	2	8	16.6
Yundum	Medina	Candidate	0.05	2015	29356	587	40	132	2	8	118
Brikama	Wellingara	Candidate	0.05	2015	30361	1518	20	33	2	18	16.6
Brikama	Wellingara	Candidate	0.05	2015	66051	1321	40	132	2	18	118
Mandinari	Wellingara	Candidate	0.05	2015	18554	928	20	33	2	11	16.6
Mandinari	Wellingara	Candidate	0.05	2015	40364	807	40	132	2	11	118
UnconnectedWestern	Wellingara	Candidate	0.05	2015	67470	3373	20	33	2	40	16.6

Wellingara	UnconnectedWestern	Candidate	0.05	2015	146780	2936	40	132	2	40	118
UnconnectedLower	Wellingara	Candidate	0.05	2015	484373	9687	40	132	2	132	118
Mile2	Mile5	Candidate	0.05	2015	5060	253	20	33	2	3	16.6
Mile5	Mile2	Candidate	0.05	2015	11008	220	40	132	2	3	118
Eboe	Mile2	Candidate	0.05	2015	11807	590	20	33	2	7	16.6
Mile2	Eboe	Candidate	0.05	2015	25686	514	40	132	2	7	118
Eboe	Wellingara	Candidate	0.05	2015	13494	675	20	33	2	8	16.6
Wellingara	Eboe	Candidate	0.05	2015	29356	587	40	132	2	8	118
Brikama	Yundum	Candidate	0.05	2015	15181	759	20	33	2	9	16.6
Yundum	Brikama	Candidate	0.05	2015	33025	661	40	132	2	9	118
Brikama	Mandinari	Candidate	0.05	2015	23614	1181	20	33	2	14	16.6
Mandinari	Brikama	Candidate	0.05	2015	51373	1027	40	132	2	14	118
UnconnectedWestern	Brikama	Candidate	0.05	2015	43855	2193	20	33	2	26	16.6
Brikama	UnconnectedWestern	Candidate	0.05	2017	95407	1908	40	132	2	26	118
UnconnectedLower	UnconnectedWestern	Candidate	0.05	2017	330254	6605	40	132	2	90	118
Soma	UnconnectedLower	Candidate	0.05	2015	50602	2530	20	33	2	30	16.6
UnconnectedLower	Soma	Candidate	0.05	2017	110085	2202	40	132	2	30	118
Farrafenni	Soma	Candidate	0.05	2015	26988	1349	20	33	2	16	16.6
Soma	Farrafenni	Candidate	0.05	2015	58712	1174	40	132	2	16	118
Soma	UnconnectedCentral1	Candidate	0.05	2017	256864	5137	40	132	2	70	118
UnconnectedCentral1	Kaur	Candidate	0.05	2017	33735	1687	20	33	2	20	16.6
Kaur	UnconnectedCentral1	Candidate	0.05	2015	73390	1468	40	132	2	20	118
UnconnectedCentral1	Bansang	Candidate	0.05	2017	256864	5137	40	132	2	70	118

Bansang	Janjanburreh	Candidate	0.05	2015	33735	1687	20	33	2	20	16.6
Janjanburreh	Bansang	Candidate	0.05	2015	73390	1468	40	132	2	20	118
Bansang	Basse	Candidate	0.05	2017	220169	4403	40	132	2	60	118
BasseDemand	Basse	Candidate	0.05	2015	67470	3373	20	33	2	40	16.6
Basse	BasseDemand	Candidate	0.05	2015	146780	2936	40	132	2	40	118
BasseDemand	UnconnectedUpper	Candidate	0.05	2015	50602	2530	20	33	2	30	16.6
UnconnectedUpper	BasseDemand	Candidate	0.05	2015	110085	2202	40	132	2	30	118
UnconnectedCentral2	UnconnectedUpper	Candidate	0.05	2017	67470	3373	20	33	2	40	16.6
UnconnectedUpper	UnconnectedCentral2	Candidate	0.05	2015	146780	2936	40	132	2	40	118
Janjanburreh	UnconnectedCentral2	Candidate	0.05	2017	67470	3373	20	33	2	40	16.6
UnconnectedCentral2	Janjanburreh	Candidate	0.05	2015	146780	2936	40	132	2	40	118
Kuntaur	Janjanburreh	Candidate	0.05	2015	33735	1687	20	33	2	20	16.6
Janjanburreh	Kuntaur	Candidate	0.05	2015	73390	1468	40	132	2	20	118
Kaur	Kuntaur	Candidate	0.05	2015	183475	3669	40	132	2	50	118
Kaur	Farrafenni	Candidate	0.05	2015	183475	3669	40	132	2	50	118
Farrafenni	UnconnectedNorth2	Candidate	0.05	2017	33735	1687	20	33	2	20	16.6
UnconnectedNorth2	Farrafenni	Candidate	0.05	2015	73390	1468	40	132	2	20	118
UnconnectedNorth2	NjabaKunda	Candidate	0.05	2017	25301	1265	20	33	2	15	16.6
NjabaKunda	UnconnectedNorth2	Candidate	0.05	2015	55042	1101	40	132	2	15	118
Kerewan	NjabaKunda	Candidate	0.05	2015	33735	1687	20	33	2	20	16.6
NjabaKunda	Kerewan	Candidate	0.05	2015	73390	1468	40	132	2	20	118
UnconnectedNorth1	Kerewan	Candidate	0.05	2017	16867	843	20	33	2	10	16.6
Kerewan	UnconnectedNorth1	Candidate	0.05	2015	36695	734	40	132	2	10	118

UnconnectedNorth1	BarraDemand	Candidate	0.05	2017	16867	843	20	33	2	10	16.6
UnconnectedNorth1	BarraDemand	Candidate	0.05	2015	36695	734	40	132	2	10	118
Barra	BarraDemand	Candidate	0.05	2015	8434	422	20	33	2	5	16.6
BarraDemand	Barra	Candidate	0.05	2015	18347	367	40	132	2	5	118

2. DEMAND

The Gambia currently only meets a proportion of its potential demand. This makes estimating demand difficult, because it is hard to say what demand would be if there was full access. In this section we arrive at an estimate of what that full demand might be and a trajectory to model it.

In this section we use a number of terms to refer to demand.

By the term **actual demand** or **met demand** we mean the demand that NAWEC has served historically.

The term **suppressed demand** is used to refer to demand that NAWEC is not currently able to meet. This includes both connected demand that is not served (**load shedding**) and currently unconnected demand.

By the term **theoretical demand** we mean an estimate of the demand that there would be if everywhere had fully reliable access to electricity. This includes both currently connected users and currently unconnected users. It is equals met demand plus suppressed demand.

The term **expressed demand** refers to a trajectory that takes the current met demand towards the theoretical demand. In real terms, we can imagine this as consumers starting to use more electricity as more households are connected and begin to buy more electrical goods. This expressed demand is a model input and is the demand the model "sees" and tries to serve from the generation and network choices available to it. This is the way that the "improved access" is represented in the model. The path this "expressed demand" follows is the path followed to reach access for all (a political objective by 2025) from the current situation.

The term **lost load** or unserved load in the model refers to the portion of the expressed demand that the model chooses not to meet because it is not economic. Unlike the other terms, this is a model output. This load has an economic value: the **value of lost load**. The model has an economic choice to meet demand through a combination of generation and network investment, or to pay the value of lost load. It might choose to not supply the highest point of the peak load, if the generation options available would be more expensive. We will report on this unserved load for each scenario.

2.1. DEMAND GROWTH

Demand growth assumptions will be based on GDP growth assumptions for both domestic and other use. Historically, GDP growth has been in the region of 3.4 to 6.3% annually. To put this in context, population growth has been in the region of 3% annually historically. During the period 2008 to 2011, The Gambia's Gross Domestic Product (GDP) grew by an average of 4.5% a year, and the Government forecast is 5.5% growth over the coming years (PAGE, 2010).

We therefore propose using a demand growth rate of 5.5% on all demand (including currently suppressed demand) for the first 5 years of the model to 2017, and the 4.5% (the average growth of Gambia GDP) for the remainder of the modelled period.

Currently, actual demand is growing at a rate of 6-19% per year (PURA 2010) due to increased electrification. In our representation, the increase in electrification is based on the demand calculation (see Section 2.2 below) and the economic response of the model to the cost of lost load (see Section 2.4).

In reality, there is no direct causal relationship between GDP and electricity demand. The two are interrelated and drive each other in complex ways.

2.2. OVERALL DEMAND

For our analysis, it will be important to understand the total theoretical level of demand. This is the level of demand if all potential users had full access to electricity all the time.

There are two issues that make representing demand a challenge. They are:

1) There is a lack of historical data for the existing customer base;
2) There is suppressed demand in the existing customer base, because of high levels of load shedding and only 10-12 hour/day service in the provincial systems; and
3) There is supressed demand in currently unconnected areas, which cannot be known for certain until it is connected.

We have used a number of key assumptions in our assessment of demand as expressed to the model:

• We have assumed the same population distribution between urban and rural within each of the Local Government Areas of the Gambia as the last national census (2003), but population distribution may have changed. The next population census is not due until 2013.

- Assuming actual demand for the urban population in each region would be approximately equal to demand per person in the Greater Banjul Area, if demand was not suppressed.
- Rural demand is typically lower than urban demand. Based on our experience in the region, we assume actual demand for the rural population would be approximately 60% of demand per person in the Greater Banjul Area, if demand was not suppressed.
- Assume 65% of demand is met in the Greater Banjul Area, accounting for current levels of load shedding. This is an estimate, but allows us to reach an overall level for theoretical demand (demand if there was no suppressed demand due to load shedding) that is broadly consistent with PURA's estimate of 596,030 MWh in 2010 (PURA 2010). In fact our estimate (gross of losses) is 594,745 MWh.
- That currently suppressed demand in the Greater Banjul Area and the largest provincial town (Basse) should be fully visible to the model by 2017 (5 years), in the other provincial towns by 2020, and in rural areas by 2025. This represents a pathway to the Gambia's ambition to electrify all demand by 2025.

The process we followed to calculate overall demand was as follows:

- Made an estimate on the population distribution for 2010 based on:
  o Population separated into rural and urban population in each Local Government Area was extracted from the last census (census 2003),
  o Historically, that urbanisation grew at a rate of 7% per year (MOE 2005), we therefore assumed a historic move from rural to urban centres over the period 2003 to 2010 to get to the model start point of 2010,
  o We also increased the overall population in line with the estimates in NOVI 2010 to get final population figures for 2010, and
  o The results of this calculation are given in Table 12.
- Made an estimate of theoretical demand (MWh/year) in each region assuming that:
  o All urban populations have have the same demand per person as the Greater Banjul Area,
  o 65% of demand is currently met in the Greater Banjul Area,
  o Losses in the Greater Banjul Area are 23.45% (PURA 2010), and
  o Therefore the theoretical demand per person in the Greater Banjul Area is 0.31MWh/year, and
  o Rural demand per person is anticipated to be 60% of urban demand based on AF-Mercados experience in West Africa.
- The results of these calculations are given in Table 14, and provided our 2010 starting point for electricity demand.
- Considering overall production in each region (Table 13), we arrived at the actually met demand in 2010.
- Arrived at a calculation for "expressed demand" (the demand that will be visible to the model) by considering that total demand should become visible linearly to the model depending on the node:
  o In the Greater Banjul Area and the largest provincial town (Basse) over the period 2013-2017 (5 years),
  o In the other provincial towns over the period 2013-2020, and
  o In rural areas over the period 2013-2025.
- In other words, the theoretical total demand becomes actually visible to the model at the rate outlined above.
- The demand is increased by 5.5% per year to 2017 and then by 4.5% per year to reflect growth in GDP (as discussed earlier).
- Expressed demand becomes closer to theoretical demand over the period 2013-2025, as shown in Figure 46. The full table of demand by node over the modelled horizon is given in Annex 2.

Role of population and GDP in the forecast:

The historical population and consumption per capita in the forecast is used to arrive at a distribution of theoretical total demand amongst the nodes of the model, some of which are not currently supplied. This distribution of theoretical demand gives the 2010 starting point of theoretical demand for the model (realised demand is based on actual production in 2010). It is not used for the forward projection.

The role of the GDP growth rate is to show the future increase of demand.

Table 12: Population estimates for 2010

Government area	2003 population (actual)	2010 population (estimate)	Urban % (2003 census)	Urban % (2010 estimate)

Greater Banjul Area, Banjul	35,061	44,376	100%	100%
Greater Banjul Area, Kanifing	322,735	408,481	100%	100%
Greater Banjul Area, Brikama	389,594	493,104	60%	79%
Lower River, Mansakonko	72,167	91,341	18%	37%
North Bank, Kerewan	172,835	218,755	20%	38%
Central River, Janjanbureh	107,212	135,697	16%	34%
Central River, Kuntaur	78,491	99,345	6%	25%
Upper River, Basse	182,586	231,097	13%	31%
Total	**1,360,681**	**1,722,196**	**50%**	**64%**

Source: AF Mercados elaboration based on Census 2003, MOE 2005 and NOVI 2010

Table 13: Actual production from power stations (2010)

Station	Region supplied	Actual production (kWh) – 2010
Kotu, Brikama and Gamwind	Greater Banjul Area	247,022,000
Essau	North Bank	982,710
Kerewan	North Bank	599,104
Farafenni	North Bank and Lower River	3,375,051
Kaur	Central River	284,059
Bansang	Central River	1,980,200
Basse	Upper River	5,152,016
Total		**259,395,140**

Source: NAWEC 2010.

Table 14: Theoretical estimate of overall demand (2010)

Government area	Actual electricity generation 2010 MWh	Theoretical estimate of demand (including suppressed) 2010 MWh
Greater Banjul Area, Banjul	11,588	13,647
Greater Banjul Area, Kanifing	106,668	125,622
Greater Banjul Area, Brikama	128,766	138,716
Lower River, Mansakonko	1,688	20,987
North Bank, Kerewan	3,269	50,721
Central River, Janjanbureh	1,132	30,695
Central River, Kuntaur	1,132	21,360
Upper River, Basse	5,152	51,564
Total	**259,395**	**453,312**

Source: AF-Mercados.

Figure 46: Theoretical and "expressed" (visible) demand

Demand (MWh/yr)
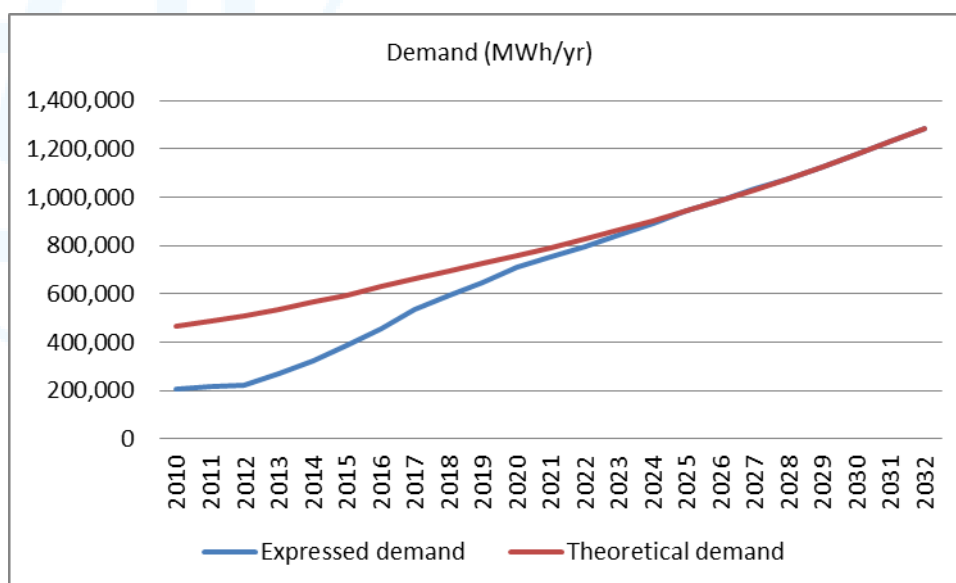
Source: AF-Mercados.

Theoretical demand over the whole period is growing with GDP, and between 2012 and 2025 the expressed demand seen by the model rises to reach this theoretical demand by the end of the analysed period. This is a result of the assumption (based on political objectives) that there will be full access by that year.

2010 to 2012 is a historical period, although we only have data for 2010 at present, as we have no information from NAWEC or PURA on the historical supplies in 2011 or 2012. Therefore we assume that between 2010 and 2012 the expressed demand is only growing with GDP: in other words, we assumed no relevant improvements have been made during these two years in terms of growth of number of clients (improving access). From 2012, we assume that the expressed demand grows sufficiently that both Basse and the Greater Banjul area theoretical demand is fully expressed by 2017, the theoretical demand in other provincial towns is fully expressed by 2020 and in the rural areas by 2025.

This assumption is about how the model "sees" demand. In other words, it represents the situation of real demand (the one the model sees) approaching to theoretical demand, which is the way to represent improvement of access in the model. When theoretical demand and actual demand (the demand the model sees) are equal, this means access is 100%. Therefore all the theoretical demand will be fully visible to the model by 2025. The model will have an economic choice to supply the demand or meet the cost of the value of lost load (see Section 2.4). The value of lost load is such that it is likely that most base demand will be economic to meet in 2025, representing achievement of the goal of full access to electricity by 2025.

It is possible that some peak supply will not be met, where it is uneconomic to meet it in comparison with the value of lost load. We will report on any unsupplied load in each scenario.

2.3. LOAD DURATION CURVE

We will represent the demand using a Load Duration Curve, as introduced in Figure 44.

In order to compute production costs and investment requirements, a load-duration curve for each year in the planning horizon must be constructed and input into the model. Moreover, for each node on the network where demand is present (a "load point"), a separate load-duration curve is required.

Normally this would include at least three or four demand blocks and reflect seasonal and monthly changes in demand (for example during the rainy season).

Unfortunately, at present only monthly generation data is available in the Gambia. There is no hourly resolution data on generation or demand available to us, and we understand no hourly meters are used. Therefore limited data is available on the shape of demand, so we have been forced to simplify this duration curve to only show peak and average demand requirements. At present only peak and average monthly generation data is available. More detailed data (for example typical hourly generation data or profile) would allow this curve to be elaborated more fully.

The duration of the peak has been chosen to be 12 hours in each month.

The height of the peak is based on peak generation data compared to average generation in each of the current systems.

Peak generation in the Greater Banjul area was 43 MW in 2010 and overall generation was 247,022 MWh. Peak generation for all the provincial systems in 2010 was 3.5 MW, and overall generation was 12,373 MWh. These provincial systems only typically operate for 12 hours per day, so their load duration curve has been adjusted accordingly (the red line in Figure 47). It is worth noting that because of extensive load shedding, the current provincial systems do not get as close to the true peak demand as the Greater Banjul area, so their peak demand is not as high compared to average.

Until 2017, we assume that only the Greater Banjul area has 24 hour supply and that the rest of the Gambia remains on 12 hour supply (see Figure 47).

From 2017, we assume that the rest of the Gambia also has 24 hour supplies, and moves towards the same peak shape as Banjul demand. The level of demand also grows as supressed demand is revealed and overall demand grows with GDP.

The implication of using this simplified demand curve is that the choice of generation may be different to a more representative demand curve.

For example, an LFO generator is cheaper to build but more expensive to run than a HFO generator. With a short peak, you might choose to have LFO generators to meet that peak and HFO generators to meet the rest of the demand. Then you are running HFO most of the time, but for the peak when generators are only running for a few load hours a month, you can use LFO so you are not spending a lot of money on capacity that is inactive most of the time. A different demand curve might result in a different choice of generation capacity, and more or less LFO compared to HFO.

In other words, more detail in the demand curve may lead to a different choice (different results) in the mix of new generation to introduce because it would be more adapted to the actual curve. The more the load shape resembles reality, the more adapted the generation assets will be to supply the demand and minimise the "full cost" (CAPEX plus OPEX plus value of unserved energy).

Figure 47: Load duration curve for 2010 expressed demand
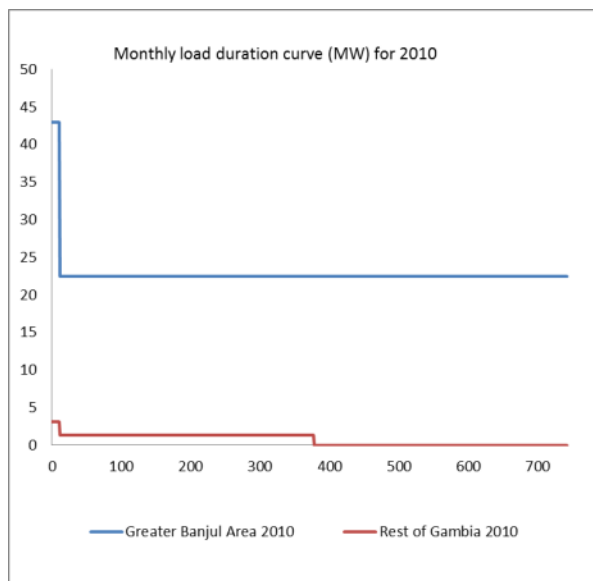
Figure 48: Load duration curve for 2030 expressed demand
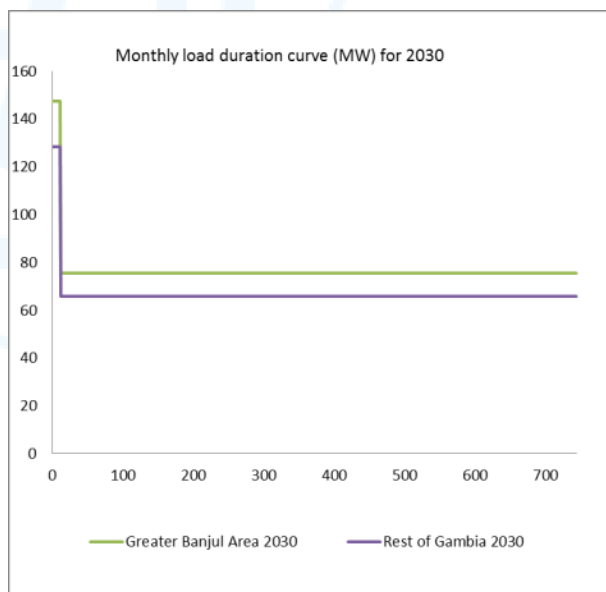
Source: AF-Mercados

2.4. VALUE OF LOST LOAD

Value of lost load is important, as it drives the rate of investment.

Representations of networks in WAPP countries typically use a cost of energy not served of around US$1,000 to 1,500/MWh (WAPP 2011). In our opinion, an appropriate figure to use in the Gambia may be around US$800/MWh. A higher value is likely to lead to very rapid investment given the current relatively low level of electrification.

This can be compared to NAWEC's current tariffs, which are around $230 to $350/MWh.

3. GENERATION

Generating capacity is broken down into three categories: existing generation facilities, planned or under construction generation facilities, and candidate generation facilities. The assumptions on these categories are discussed in the following points, and summarised in Table 16.

3.1. EXISTING GENERATION FACILITIES

Table 16 shows technical data for existing HFO and LFO generation facilities (all engines) and wind generation site. Also included is the location of each facility on the transmission network (see Figure 45). We do not have data on the efficiency, availability and CO2 emissions of current power plants, so we have used representative averages (EC 2008, EEG 2003).

We understand that the existing NAWEC plants use about 0.24 litres/kWh overall (individual plant figures are not available). This represents around 45% efficiency,[5] which is higher than industry expected standards of around 40% net efficiency (IEA 2010 and WAPP 2011). For this study we propose using the lower figure of 40% net efficiency for both existing and new HFO plants.

NAWEC and GEG were unable to supply operation and maintenance costs for existing sites, so we will use the operating cost of candidate generation.

We have deliberately not included early plans for: 35-40 MW HFO plant(s) in the Greater Banjul area developed by Aldwych/Jacobsen. These plants have not yet had funding committed and we want to explore whether they are part of the least cost solution.

3.2. CANDIDATE GENERATION

The types of generation available for selection by the model are described in the following sections.

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[5] Based on an energy content of HFO of 10.786 kWh/litre

3.2.1. CONVENTIONAL

Controllable, conventional technologies are essential in power systems to allow the grid stability to be maintained. Without these controllable technologies, more variable renewable generation cannot be integrated at scale. These conventional technologies can be fired by fossil fuel, but also include low carbon options like controllable large scale hydro.

Alternative fossil fuel technologies should be considered because at present they provide some of the lowest cost and most reliable forms of power generation, although they do have environmental implications.

a)   *Fuel oil*

At present, the Gambian power sector is heavily reliant on oil-fired engines.

Oil-fired technologies are likely to continue to play an important role because they are relatively quick to build, they can be built at a wide range of scales (including quite small scale to suit a small country like the Gambia), the fuel (oil) is relatively easy to transport and the generation plants have low capital costs compared to other generation types. However, the disadvantage is that they have higher running costs than many other plant types. Diversification from current oil technologies might help mitigate against the risk of changes in oil prices.

At present HFO capacity and delivery is only available at Kotu and Brikama, although there are plans to introduce new plants at Farrafenni and Basse. In the model, we allow heavy fuel oil investment at larger demand points in the Greater Banjul area (Kotu and Brikama) and in major demand centres outside the capital (Farrafenni and Basse, where HFO investment is planned).

Light fuel oil is available for investment at all nodes.

b)   *Coal*

Of other conventional fossil fuel technologies, coal is likely to provide the most appropriate scales of plant, ease of import and low operational cost. Coal prices have tended to be less volatile than oil or gas. Coal could therefore help improve price stability as part of a more diverse grid mix. Coal plants also offer the opportunity for co-firing with biomass, reducing the CO_2 impact and giving greater diversification.

However, the prospect of coal development has the potential to be contentious in the Gambia and met with some negative reaction in the discussion workshop. The important drawback for coal is the carbon intensity and therefore environmental impact. CO_2 emissions are higher than oil-fired generation at around 0.85 tCO_2/ MWh, compared to 0.595 tCO_2/ MWh. As a result of concerns about environmental impact, international finance institutions have become increasingly cautious about lending to coal-fired projects, unless they are cleaner than alternatives (for example, rehabilitating old coal plants in India to bring them up to modern environmental and efficiency standards).

Coal can be an emotive issue and it is therefore worth considering the development of coal in an international context:

- Coal currently produces around 40% of global power requirements and is widely used in both the developing and developed world. For example, 49% of generation in the USA is from coal, 46% in Germany, 92% in South Africa and 69% in India (IEA 2010).
- **South Africa** was facing a crisis of generation, and the power utility Eskom was struggling to finance generation needs. In April 2010, the World Bank granted the country around a $3 billion loan for Medupi supercritical coal plant (4,800 MW), due to start generation in 2313, with additional loans for renewable and energy efficiency projects. The President of the World Bank stated that, "Coal is still the least-cost, most viable, and technically feasible option for meeting the base load power needs required by Africa's largest economy". The loan from the World Bank has been highly controversial, with opposition from some local groups within South Africa and global NGOs.
- The National Electricity Board of **Senegal** (SENELEC) has commissioned the construction of a 125 MW coal power plant to help meet the growing electricity demand in Senegal. This will require an investment of CFAF 118 billion, through a "Build, Own, Operate (BOO)" arrangement. The power plant will be located near Bargny Minam village, 32 km from the city of Dakar, on a total land area of 29 hectares. The main funders of the project are the ADB Group, ADB and BOAD. The project was subject to an environmental and social impact assessment, which was reviewed as part of the due diligence process, mandated by the donors. The project has been designed to comply with the relevant environmental and social requirements of the World Bank and will apply the standards set by the World Bank for atmospheric emissions (Sendou 2009).
- Coal is a key source of electricity in the **USA**, accounting for about half of electricity generation historically (42% in 2011). The American Coalition for Clean Coal Electricity (ACCCE) has carried out analysis to show that, generally, states that have the highest penetration of coal have the lowest electricity rates. In 2011, 30 states had electricity rates

below the national average retail price of 9.99 cents/kWh. Those 30 states which generate 60% of their electricity on average from coal paid an average of 8.7 cents/kWh.

- The **IEA World Energy Outlook 2011** highlighted that coal will continue to play an important role, stating that "more than half of the … increase in on-grid electricity generation capacity is expected to be coal-fired."
- According to the World Coal Association, coal is the most widely geographically distributed fossil fuel energy resource, and it has been estimated that there are over 860 billion tonnes of proven coal reserves worldwide, sufficient to last over a hundred years at current rates of consumption. Reserve estimates vary and should always be treated with caution. They depend on economic drivers and significant unproven potential coal resources mean that some analysts believe that coal could last considerably longer.
- According to the IEA Clean Coal Centre, there are over 2,300 coal-fired power stations worldwide (7,000 individual units). Approximately 620 of these power stations are in China.

Within this global context, any small coal generating unit of the scale possible in the Gambia (say, 70MW) would be very small, and the Gambia is currently more likely to be impacted by the climate change caused by developed countries than to be a major contributor to climate change.

Within the model, coal is considered as an investment option only relatively near the coast or port facilities, because of the logistical challenge of bringing coal inland. This means probably in the Greater Banjul Area, or possibly Barra. At present the cost assumptions are based on WAPP 2011 for three scales of coal power plant 70 or 125MW circulating fluidised bed (CFB) and 250MW pulverised coal (PC) plant. The costs do not include the required port facilities for unloading and conveying the coal to the power plant. Similar scales of coal plant have been proposed in Senegal, Niger and (further afield) in Mauritius. In common with the Gambia, these countries have few hydroelectric and gas resources. Moreover, Niger has coal mines.

Coal does appear to be a viable economic option in our analysis, and offers an option for diversification away from oil-fired stations. To validate this conclusion, there would need to be a full technical feasibility study, including the cost for appropriate port facilities. We would also recommend a full environmental and social impact assessment.

c) Gas

Gas is less carbon intensive than coal or oil.

There is no gas pipeline to the Gambia. An extension of the West Africa gas pipeline may be a very long term opportunity, but would be a major undertaking. Therefore, gas could currently only be imported by ship as LNG (liquefied natural gas), requiring an LNG import and regasification facility. This would add greatly to the cost, technical complexity and required scale of development in the Gambia.

Various types of LNG regasification facilities and storage are possible. For the purpose of this exercise we will consider two representative scenarios:

- A 300MW combined cycle gas turbine (CCGT) with direct water cooling (coastal location), including the cost of a basic receiving terminal with mixed storage (some on land and some floating) using permanent manifold to land at €111m (equivalent to US$0.472m/MW additional CAPEX).
- A 150MW open cycle gas turbine (OCGT), including the cost of a land based regasification storage facility at €103m (equivalent to US$0.875m/MW additional CAPEX).

Both are expected to be in coastal locations, for ease of delivering the LNG. Operating costs are around 20% of capital costs.

These costs are just estimates based on our experience of standard facilities. From our economic modelling, gas is not currently the least cost option. If LNG did appear to be an economic option in the future, there would need to be a full technical feasibility study. We would also recommend a full environmental and social impact assessment.

d) Hydro

There are no identified opportunities for large or small scale (run of river) hydro in the Gambia itself, as the country is largely flat with no 'head' (a height of water pressure that can be used for generation).

However, large scale hydro at a regional level provides a very attractive opportunity for low carbon conventional power development. The OMVG project includes a 225 kV interconnection simple line simple circuit crossing Guinea, Senegal, Guinea-Bissau and The Gambia to share the hydroelectric production of the sites of Kaléta and Sambangalou. Sambangalou would have an installed capacity of 128 MW and Kaleta of 240 MW. Through the OMVG, The Gambia should receive from 12% of the power of the two dams.

The success of large scale hydro in the WAPP region will be dependent on regional negotiations.

e) Nuclear

Nuclear is not considered appropriate because of scale, technical complexity and risk.

3.2.2. RENEWABLE

More developed renewable technologies provide a mechanism to reduce exposure to fossil fuel prices and to reduce carbon emissions. These are discussed below and include wind, solar PV, biomass, waste to energy and landfill gas.

Various emerging technologies have been proposed for the Gambia. These include wave and tidal power, and concentrated solar power (CSP). At present, these technologies are at the early stage of demonstration and their costs and efficiency (or capacity factor) have not been adequately demonstrated. Also, because of their early stage of development, the costs are very high. They are not considered appropriate for a small system in a developing country where both reliability and affordability are of major concern. If demonstration projects in developed countries show adequate reductions in costs and improvements in reliability in the future, these technologies could be reconsidered.

Wind and solar PV seem likely to remain the most appropriate renewable power options in the Gambia in the near term.

a) Wind

Wind data in the Gambia is limited. Capacity factors in the coastal regions are estimated in the region of 7.5-10% based on the GEF-UNIDO report and anecdotal information from Gamwind. This is significantly lower than would be considered economic in other regions such as Europe, although the economics can be improved by using older, refurbished machines. In Lahmeyer, out of the provincial towns, only Kerewan is considered for potential small wind development as it has better wind resource. Other provinces are judged to have insufficient wind conditions. In contrast, data from QCell for a few sample years seems to indicate above average speeds for the region in apparently disconnected areas including Yundum (Greater Banjul Area), Kuntaur (Central River Region), and Yallal (North Bank).

The wind resource is primarily on the coast and inland developments are not anticipated to be economic. New developments at a larger scale will be constrained by the difficulties of importing suitable cranes for large wind projects.

Figure 49: Zero wind map of The Gambia at 50m above ground
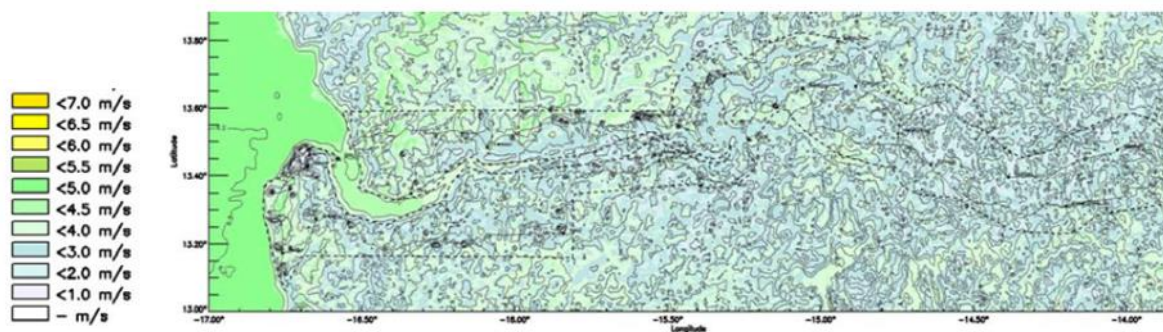
Source: Renewable Electricity Master Plan, Lahmeyer International (2006)

There may be other concerns about in developing new wind projects are. The Gambia has a diverse bird population and potential bird impacts have not been studied to determine best siting, although at present planned low mast heights and smaller machines may mitigate this impact. There are also grid stability concerns, as the wind variability may not be able to be managed well by the current generation mix. The grid is currently not stable, with frequent load shedding and power quality issues. Large volumes of variable wind power would be difficult to manage on the current power system. There are also safety concerns, such as the potential for blade shearing, in populated areas.

b) Solar PV

Solar PV is available for investment at all nodes, reflecting the good solar regime throughout the country.

Environmental impacts of solar PV are minimal. However, dust on panels is a significant issue for performance. These panels will need to be cleaned regularly, and it is anticipated that a plan to use recycled water is likely to be required by NEA.

Figure 50: Solar maps of the Gambia for December 2005 (top) and January 2006 (bottom)
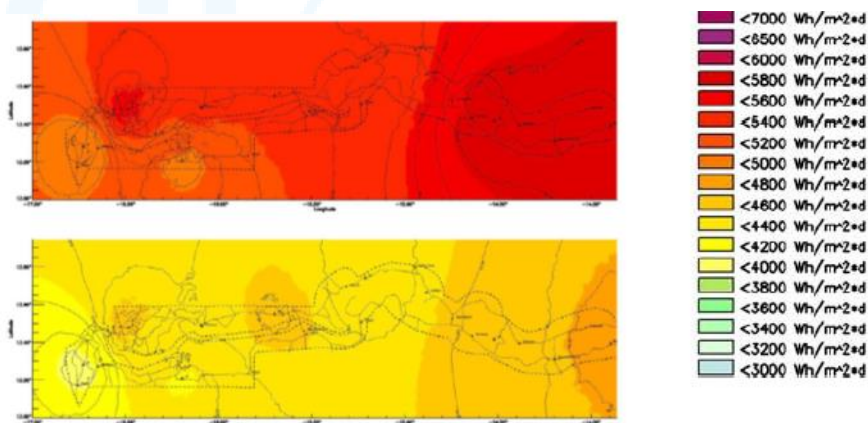
Source: Renewable Electricity Master Plan, Lahmeyer International (2006)

We understand that an ECREEE-funded 20MW solar PV project is currently under negotiation, and has even been suggested as possibly being completed by the end of 2012. However, it seems that tariff negotiations have not yet been successful, so it is not clear that the project will proceed.

c)   Biomass

The use of fuel wood and residues from wood processing for electricity generation is not encouraged because wood and charcoal are used extensively for domestic cooking and deforestation is a major issue for the Gambia.

We understand that a co-firing facility for groundnut shells was built, but is currently no longer operational.

Groundnut briquettes have been proposed as a solution to these domestic cooking issues. Greentech has a facility to process waste groundnut shells to briquettes that are usable for cooking. These are designed to be burnt in efficient stoves. Greentech sells these efficient stoves for around 320 dalasi (around US$10-15). This price can still be a barrier for women to buy, as men generally control the household budget.

Technically these briquettes could be used for electricity generation. However, Greentech prefers to remain true to their original objectives of reducing deforestation. Commercially it makes little difference to them as they can sell to either use, but they don't want to divert biomass to electricity when other options are available.

There are 40,000 tonnes per year of waste groundnut shells. The plant can also process sawdust, but there is a much lower availability at only 3,000 tonnes per year. Sawdust is the only (relatively) unused by-product of forestry available in a small number of discrete locations. Sawdust does have alternative uses for poultry.

More generally NEA has raised concerns that groundnuts treated with illegal strong pesticides may cause a risk when using in confined kitchens. Greentech and other stakeholders felt this was unlikely due to the high temperature processing process.

Cashew and jatropha energy crops grow well in the Gambian climate. Views from stakeholders on the use of energy crops are mixed.

Proponents support the benefits that new industry could bring to the Gambia and greater energy self-sufficiency. However, there are serious concerns about land use. There is limited agricultural land in the Gambia and it may be appropriate to prioritise use for food production. Greater pressure on land use could further encroach on forestry.

Overall, it seems that before significant energy crop development is considered, a wider strategy on agricultural land use for energy crops should be developed to ensure that food production is not constrained or undesirable pressure is put on forestry.

The use of other types of biomass is quite low due to the limited availability of agricultural waste and other potential sources.

Biogas power generation is also quite complex technology, and presents a challenge in gathering sufficient quantities of appropriate waste. Biogas has been considered. There are issues with collection. There may also be sustainability issues as cow dung (manure) is used on farms at present. There is also an explosion risk, particularly in rural areas where there are thatched houses.

The Peri-Urban Project for Agriculture installed 20 biogas digesters in rural and periurban areas, with what seems to be mixed success.

Biogas power generation is significantly more expensive to build and operate than standard biomass using groundnut shell briquettes. Therefore, for the economic model standard biomass power generation is considered. Waste biomass power plant capacity is a potential for investment in the Greater Banjul Area and Kaur because of the location of groundnut processing facilities.

d) Landfill and Waste

Waste management is a visible issue for the Gambia, reflected in the national campaign "Operation Clean the Nation" by Gambia's president. Some waste-to-energy projects have been proposed.

Most refuse from hotels is taken to the Kotu landfill site. Municipal rates are supposed to cover waste collection, but in practice each hotel has to remove their own waste.

Waste to energy is currently expensive and technically complex compared to alternatives. We understand that Naanovo Energy Gambia Limited was approved to construct a 14 MW waste to energy plant in the Gambia. The foundation stone was laid in 2007, but little progress has been made since. It seems likely that this project is not proceeding.

More recently, Project Lighthouse Gambia was planning a landfill gas CHP unit under the Clean Development Mechanism (CDM). They signed a Memorandum of Understanding with Kanifing Municipality Council which guaranteed them exclusive use of Gambia's only organised landfill. However, as little more progress on the project has been made it seems unlikely to proceed.

Landfill gas seems unlikely to be a strong possibility in the Gambia because landfill is not compacted, reducing the concentration of methane emissions.

Within the economic model, Energy from Waste is only available near the landfill site. Data on costs and operation is from IEA 2010.

e) Emerging technologies: CSP

Concentrated solar power systems use mirrors or lenses to concentrate a large area of sunlight, or solar thermal energy, onto a small area. Electrical power is produced when the concentrated light is converted to thermal energy of a working fluid (molten salts, water/steam), which drives a heat engine (usually a steam turbine) connected to an electrical power generator.

Instead of immediately transforming the thermal energy into power, it is possible to store heat temporarily. It is also possible to hybridize the power plant with other conventional or controllable renewable (biomass) sources of energy. These solutions, storing and hybridization, improve the management of the power output of the plant, which is an important benefit to system stability.

The solar thermoelectric sector is still on the phase of commercial take off. After the first early projects in the United States in the 80's and early 90's, development has been practically stalled until the beginning of a new expansion phase in the 2000's. Since then, commercial development has been most significant in Spain. In 2010, the global installed capacity was 1,061 MW, of which approximately 60% was located in Spain, new capacity under construction was 1,160 MW (1,000 MW in Spain) and another 5,868 MW was in development (843 MW in Spain).

There are four principle technologies: Parabolic Cylinder Concentrator (PCC), Compact Fresnel linear reflector (Fresnel), Central receiver system (Tower), and Parabolic Disc with external combustion motor (also known as Stirling disc as they are articulated using the motor of the same name).

Table 15: Comparative table of CSP technologies

Technology	Description	Applications	Advantages	Disadvantages
PCC	Basically conventional plants in which the fuel used to generate and overheat steam replaced by solar radiation. Solar energy is concentrated using parabolic collectors that track the sun on one axis.	Grid connected plants. Maximum demonstrated nominal capacity: 80 MWe	Most mature technology at commercial level and the predominant worldwide. Maximum solar-electricity performance 21%. Possible to hybridize and add storing capacity.	Moderate operating temperatures (up to 400°C) due to thermal limitations of the oil use as working fluid. Molten salts are expensive (Direct Steam Generation is under development and may have the potential to reduce cost)

Technology	Description	Applications	Advantages	Disadvantages
Fresnel	Uses flat (or slightly curved) mirrors, positioned in parallel sheets over a horizontal land, that can rotate around its axis to reflect the solar rays towards a fixed tubular receptor located on a higher level.	Small generating systems, island configuration or grid connected plants. Maximum demonstrated nominal capacity: 5 MWe. Heat process production.	Expected to have a low installation and maintenance cost (although at the moment it is not that relevant as the technology is on the first stage of the learning curve).	Lower efficiency (it is only possible to obtain low temperatures). Moderate operating temperatures: 250°C in saturated steam generation and up to 400°C for overheated steam (not yet demonstrated). Uncertainty in costs.
Tower	The solar radiation concentrator system consists of a field of heliostats made of reflective surfaces that, by 2 axis tracking, project the sun on a receiver usually located on top of a tower. Inside the central receiver solar energy is transformed into thermal energy through the enthalpy variation of a working fluid.	Grid connected plants. Maximum demonstrated nominal capacity: 20 MWe. Heat process production at high temperature.	High performance is expected in the medium term (solar collection performance 46% at temperatures of 565°C and instantaneous solar to electricity 23%) High temperature storage and hybridization possible.	This technology it is not yet mature, so the capital cost estimation is not very reliable.
Stirling Disc	The concentrator disc is a reflecting surface of revolution, of parabolic section, that concentrates the incident solar rays to a focal point, where the power transforming block is located. The entrance of the power block is composed of a cavity receptor that absorbs the solar energy and turns it into thermal energy using a Stirling motor. The movement produced by the Stirling motor it is used by an induction generator to obtain electric energy.	Small generating systems on and off grid. Maximum demonstrated nominal capacity: 25kWe.	High performance (instantaneous solar to electricity around 30%) Modularity Hybridization capacity Operating experience.	This technology it is not yet mature, so the capital cost estimation is not very reliable. Hybrid system has a low combustion performance and its reliability is yet to be proven.

Spain has been a technological leader, and as such has had an influence on the development of the technology. In Spain, there was a 500 MW overall cap on development and 50 MW per site, so companies able to install greatest capacity in the shortest time were rewarded and the more mature technologies were preferred. This is why virtually all the plants built or under construction are PPC.

The generation price of CSP is still uncertain due to the continuous technological innovations in materials, designs and production methods. The commercial maturity of the different technologies is also uneven. In any case, the generation costs are well above those of conventional fossil fuel plants. The reason is that conventional plants are fueled by a highly concentrated energy source (with high calorific power) allowing energy transforming devices to be very compact. They also require less material and their production process is well advanced in the experience curve.

This gap between the cost of conventional and solar plants is especially significant in the capital investment cost.

There is potentially a large cost reduction potential of the solar plants, in the mid-term decisive progress in cost reduction is expected. The amount of this reduction in the incoming years will be decisive to determine if the solar thermo electric technology stands as a serious alternative to conventional generation without a strong promotion frame backing it up.

The investment cost of a PCC plant with 110 MW nominal capacity are approximately US$6.57/MW, fixed operating costs of US$0.07/MW/year and variable operating costs of US$2.52/MWh (source: NREL). This plant might have 1,750MWh-thermal of storage capacity and generate 361 GWh annually.

It is difficult to envisage any solar thermal power generation plant as a near term electricity supply option for the Gambia. The first reason is the relatively small power capacity requirements in the country. At the present technology state of the art, the technical and economic viability of such Concentrated Solar Power (CSP) power plants are in the same or over range of installed capacity in the whole country. Becoming reliant on a technically early stage technology for a very significant

proportion of the power requirements of the country would be highly undesirable. Such technologies would be expected to have significant downtime, and additional capacity would be needed to cover the demand in these periods. Furthermore, the relatively high cost of the technology at present is not likely to make it part of a least cost development plan.

Concentrating solar power may have significant potential environmental issues as there is a risk of heat tank leakage, and they have high water use. They are generally large facilities with numerous highly geometric and highly reflective surfaces, so solar energy facilities may create visual impacts

At their current state of development, CSP is not recommended. Solar thermal power could be an interesting long term option once the technology is more robustly commercially demonstrated so the costs and expected generation is clearer, has moved further along the learning curve to make it more affordable, and once the Gambia is part of a more robust interconnected power pool with adequate reserve capacity and power stability.

f)   Emerging technologies: Wave and tidal

The most established form of tidal power generation is through a tidal barrage. This is a massive engineering project, and involves building a barrage across a bay or river that is subject to tidal flow. Turbines installed in the barrage wall generate power as water flows in and out of the estuary basin, in a similar way to a hydro dam that produces head (a height of water pressure). As with hydro, environmental impacts from barrages can be significant.

The viability of tidal barrage schemes is highly location dependent. The available power varies with the square of the tidal range, so barrage is best placed in a location with very high-amplitude tides.

Tidal barrage is therefore not likely to be a possibility in the Gambia. The available power for a tidal barrage varies with the square of the tidal range (the difference between high and low tides), so a barrage is best placed in a location with very high-amplitude tides. The tidal range in the Gambia is relatively small (at Banjul the range is 1.6 m in spring tides and 0.7 m in neap tides). By contrast, the tidal range at La Rance tidal barrage in France averages 8 metres and reaches up to 13.5 metres.

Tidal stream generators can be thought of like underwater wind turbines. Currently designed prototypes use rotors to try to capture energy from coastal currents. At the present time there are no fully commercial devices, although some near commercial scale prototypes are being tested. The impacts of tidal stream generators not been studied in depth. Local effects are likely to include seabed disturbance due to the impacts on silt, and also potential impacts on marine wildlife - specifically by collision.

Tidal stream generators require very fast tidal currents, such as those found between islands. Tidal currents along most of the coast are weak (< 0.1 m/s) except for the Gambia estuary, where tidal filling and emptying causes tidal currents to be over 1 m/s. However, it is not yet clear whether such currents will be sufficient for the economic use of tidal stream generators. For example, the tidal test site at the European Marine Energy Centre (EMEC) on Orkney in Scotland offers high velocity marine currents, which reach almost 4 m/s at spring tides.

Wave generation is probably at an earlier stage of development than tidal stream, although again some prototypes are under development. There is less harmonisation in the type of design being tested, with a wide range of possible prototypes at very different stages on the development pathway.

At present, wave and tidal stream technologies are at an early stage of demonstration and their costs and achieved capacity factor have not been demonstrated. Both types of generators require the engineering of complex moving equipment in a wet, salty and extremely robust environment (strong currents or waves). This is a very big technical challenge, and it is not yet clear how successful these devices will ultimately be. Also, because of their early stage of development, the costs are currently very high (essentially each new project is "first of a kind").

3.3. SYSTEM STABILITY: THE IMPORTANCE OF GENERATION CHOICES

Severe **frequency excursions** (abnormal frequency events) are normally avoided through the use of operating reserve to limit the extent of frequency divergence. Frequency excursions can take many forms, from slow-acting inaccuracies in the forecasting of demand, where demand and generation drift out of balance over time, to sudden shocks to the system following the loss of significant generation or demand due to a plant or network fault.

The operating reserve is required in a number of different forms, depending on the timeframe over which it is required to operate and the type of incident to which it responds. Hence, operating reserve requirements range from small short-term frequency variations to load-following over longer time frames, and further include the need to respond to sudden large imbalances following the loss of a major generating unit.

Primary reserve is the most critical form of reserve for system security. It acts in the very short timescales of a few seconds to stop the fall in frequency following an incident. There are two forms of primary response:

- **Inertial response** – inherent response of synchronised generators to changes in the system frequency; and
- **Fast response** – automated action to increase generation from scheduled plant – for example, in the case of steam cycle plant, by releasing the potential energy stored as steam pressure within the boilers (which is not big in capacity terms but very fast in time-response terms)

A useful indicator of a generator's inertial response is provided by the "inertia" constant H. The H constant is the generator's stored energy divided by generator rating, and hence is measured in seconds. It may be interpreted as the time in seconds a generator can generate full power output from its own kinetic energy. The longer this is the more "inertia" (or ability to react to a frequency change) the generator gives to the system.

Fuel oil engine generation plants have a low inertia value. This causes the system to be more unstable when compared to a system with high inertial rotatory machines such as steam turbines.[6] Therefore, the adding steam turbine based technology (whether oil- or coal-fired) in the Gambia can be crucial to maintain system adequacy.

The fact that NAWEC are managing a system with only engines at present may be one of the reasons for frequent frequency disturbances in the Gambia.

The future addition of variable renewable generation capacity may lead to significant additional stability problems in the grid if proper action is not taken. Spinning reserves or load shedding schemes may not be able to act to rescue the system if the rate of frequency drop is too high (e.g. a sudden big decrease in variable renewable generation, which can be critical if the renewable share in the system is high). Reducing the rate of frequency drop (directly linked to primary reserves) will provide a solution as it provides more time for the governors to act and even for load shedding to take place. The more inertia there is in the system, the more variable generation it can manage.

Detailed studies should be undertaken to analyse and calculate the reserve requirements of the country, even at the current stage of system development.

3.4. EMISSIONS

It is possible to represent a cost of CO_2 emissions in the model. The Gambia does not currently have any charging for CO_2 emissions, so this will be set to zero in all the scenarios. However, we will report on CO_2 emissions from all scenarios.

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[6] Typical H figures (in seconds) for a variable load engine are 1 – 5, and for steam turbines are 3 – 9 (Source: Grainger, J J and Stevenson, W J., "Power system analysis", Wiley, 1994.)

Table 16: Existing, planned and candidate generation

Generator Name	Technology	Location	Status	Year available	CAPEX $m/MW	Variable O&M cost $/MWh	Fixed O&M cost $k/MW year	Amortization time	Build time years	Max available cap	Minimum build capacity	CO2 Emissions tCO2/MWh	Availability (%)	Thermal Efficiency MWh input/MWh output
Kotu KPS-G1	LFO existing	Kotu	Existing	1981	-	10.1	8.4	20	1	2.6	0	0.595	80%	41%
Kotu KPS-G2	LFO existing	Kotu	Existing	1981	-	10.1	8.4	20	1	0	0	0.595	0%	41%
Kotu KPS-G3	HFO existing	Kotu	Existing	1997	-	7.1	16.8	20	1	2.6	0	0.595	80%	40%
Kotu KPS-G4	HFO existing	Kotu	Existing	2001	-	7.1	16.8	20	1	5.5	0	0.595	80%	40%
Kotu KPS-G6	HFO existing	Kotu	Existing	1990	-	7.1	16.8	20	1	0	0	0.595	0%	40%
Kotu KPS-G7	HFO existing	Kotu	Existing	2001	-	7.1	16.8	20	1	5.5	0	0.595	80%	40%
Kotu KPS-G8	HFO existing	Kotu	Existing	2001	-	7.1	16.8	20	1	5.5	0	0.595	80%	40%
Kotu KPS-G9	HFO existing	Kotu	Existing	2009	-	7.1	16.8	20	1	5.5	0	0.595	80%	40%
Brikama BRK-G1	HFO existing	Brikama	Existing	2006	-	7.1	16.8	20	1	5.5	0	0.595	80%	40%
Brikama BRK-G2	HFO existing	Brikama	Existing	2006	-	7.1	16.8	20	1	5.5	0	0.595	80%	40%
Brikama BRK-G3	HFO existing	Brikama	Existing	2007	-	7.1	16.8	20	1	5.5	0	0.595	80%	40%
Brikama BRK-G4	HFO existing	Brikama	Existing	2007	-	7.1	16.8	20	1	5.5	0	0.595	80%	40%
Bara G1	LFO existing	Barra	Existing	2006	-	10.1	8.4	20	1	0.048	0	0.595	50%	41%
Bara G2	LFO existing	Barra	Existing	2006	-	10.1	8.4	20	1	0.16	0	0.595	50%	41%
Bara G3	LFO existing	Barra	Existing	2006	-	10.1	8.4	20	1	0.16	0	0.595	50%	41%
Kerewan G1	LFO existing	Kerewan	Existing	2006	-	10.1	8.4	20	1	0	0	0.595	0%	41%
Kerewan G2	LFO existing	Kerewan	Existing	2006	-	10.1	8.4	20	1	0	0	0.595	0%	41%
Kerewan G3	LFO existing	Kerewan	Existing	2006	-	10.1	8.4	20	1	0	0	0.595	0%	41%
Kerewan G4	LFO existing	Kerewan	Existing	2006	-	10.1	8.4	20	1	0.36	0	0.595	50%	41%
Kaur G1	LFO existing	Kaur	Existing	2006	-	10.1	8.4	20	1	0.048	0	0.595	50%	41%

Generator Name	Technology	Location	Status	Year available	CAPEX $m/MW	Variable O&M cost $/MWh	Fixed O&M cost $k/MW year	Amortization time	Build time years	Max available cap	Minimum build capacity	CO2 Emissions tCO2/MWh	Availability (%)	Thermal Efficiency MWh input/MWh output
Kaur G2	LFO existing	Kaur	Existing	2006	-	10.1	8.4	20	1	0	0	0.595	0%	41%
Kaur G3	LFO existing	Kaur	Existing	2006	-	10.1	8.4	20	1	0.048	0	0.595	50%	41%
Farafenni G1	LFO existing	Farrafenni	Existing	2006	-	10.1	8.4	20	1	0.2	0	0.595	50%	41%
Farafenni G2	LFO existing	Farrafenni	Existing	2006	-	10.1	8.4	20	1	0.6	0	0.595	50%	41%
Farafenni G3	LFO existing	Farrafenni	Existing	2006	-	10.1	8.4	20	1	0.6	0	0.595	50%	41%
Bansang G1	LFO existing	Bansang	Existing	2006	-	10.1	8.4	20	1	0.2	0	0.595	50%	41%
Bansang G2	LFO existing	Bansang	Existing	2006	-	10.1	8.4	20	1	0.2	0	0.595	50%	41%
Bansang G3	LFO existing	Bansang	Existing	2006	-	10.1	8.4	20	1	0.2	0	0.595	50%	41%
Basse G1	LFO existing	Basse	Existing	2006	-	10.1	8.4	20	1	0	0	0.595	0%	41%
Basse G2	LFO existing	Basse	Existing	2006	-	10.1	8.4	20	1	0	0	0.595	0%	41%
Basse G3	LFO existing	Basse	Existing	2006	-	10.1	8.4	20	1	0.45	0	0.595	50%	41%
Gamwind1	Wind	Eboe	Existing	2010	-	-	42.5	20	1	0.15	0	0	8%	100%
Tanji fishing wind	Wind	Eboe	Planned	2014	Confidential			20	2	0.45	0	0	8%	100%
PV at Kuar	Solar	Eboe	Planned	2014				20	2	0.06	0	0	20%	100%
Gamwind 2	Wind	Eboe	Planned	2014				20	2	0.9	0	0	8%	100%
M'Bolo wind and solar	Wind	Yundum	Planned	2014				20	2	0.0083	0	0	8%	100%
ASNAPP Gamsolar 1 North Bank	SolarPV	BarraDemand	Planned	2014				20	2	0.002772	0	0	20%	100%
ASNAPP Gamsolar 2 Western Bank	SolarPV	Yundum	Planned	2014				20	2	0.005544	0	0	20%	100%
Qcell repeater stations 1 Foni	SolarPV	Yundum	Planned	2014				20	2	0.0084	0	0	20%	100%
Qcell repeater	SolarPV	Yundum	Planned	2014				20	2	0.0084	0	0	20%	100%

Generator Name	Technology	Location	Status	Year available	CAPEX $m/MW	Variable O&M cost $/MWh	Fixed O&M cost $k/MW year	Amortization time	Build time years	Max available cap	Minimum build capacity	CO2 Emissions tCO2/ MWh	Availability (%)	Thermal Efficiency MWh input/MWh output
stations 2 Foni														
Qcell repeater stations 3 Jarra	SolarPV	Farrafenni	Planned	2014				20	2	0.0084	0	0	20%	100%
Qcell repeater stations 4 Jimara	SolarPV	Basse	Planned	2014				20	2	0.0084	0	0	20%	100%
Qcell repeater stations 5 Kantora	SolarPV	Basse	Planned	2014				20	2	0.0084	0	0	20%	100%
Qcell repeater stations 6 Sandu	SolarPV	UnconnectedNorth2	Planned	2014				20	2	0.0084	0	0	20%	100%
Qcell repeater stations 7 Sanjal	SolarPV	Kaur	Planned	2014				20	2	0.0084	0	0	20%	100%
Qcell repeater stations 8 Baddibu	SolarPV	Kerewan	Planned	2014				20	2	0.0084	0	0	20%	100%
Qcell repeater stations 9 Jokadu	SolarPV	BarraDemand	Planned	2014				20	2	0.0084	0	0	20%	100%
Qcell repeater stations 10 Nuimi	SolarPV	BarraDemand	Planned	2014				20	2	0.0084	0	0	20%	100%
IDB Brikama expansion	HFO new	Brikama	Planned	2012				20	2	9	9	0.595	80%	40%
Brikama BRK-G5	HFO new	Brikama	Planned	2013				20	2	6.4	6.4	0.595	80%	40%
Brikama BRK-G6	HFO new	Brikama	Planned	2013				20	2	6.4	6.4	0.595	80%	40%
Fara new HFO	HFO new	Farrafenni	Planned	2013				20	2	4	4	0.595	80%	40%
Basse new HFO	HFO new	Basse	Planned	2013				20	2	1	1	0.595	80%	40%
New wind (sub 500kW refurbished)	Wind	Mile2	Candidate	2014	0.9	-	42.5	20	2	10	0.5	0	8%	100%

Generator Name	Technology	Location	Status	Year available	CAPEX $m/MW	Variable O&M cost $/MWh	Fixed O&M cost $k/MW year	Amortization time	Build time years	Max available cap	Minimum build capacity	CO2 Emissions tCO2/ MWh	Availability (%)	Thermal Efficiency MWh input/MWh output
New wind (sub 500kW refurbished)	Wind	Mile5	Candidate	2014	0.9	-	42.5	20	2	10	0.5	0	8%	100%
New wind (sub 500kW refurbished)	Wind	Kotu	Candidate	2014	0.9	-	42.5	20	2	10	0.5	0	8%	100%
New wind (sub 500kW refurbished)	Wind	Eboe	Candidate	2014	0.9	-	42.5	20	2	10	0.5	0	8%	100%
New wind (sub 500kW refurbished)	Wind	Sanyang	Candidate	2014	0.9	-	42.5	20	2	10	0.5	0	8%	100%
Solar (over 50kW)	SolarPV	Mile2	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Mile5	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Kotu	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Eboe	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Bijilo	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Medina	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Brikama	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Wellingara	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Sanyang	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Yundum	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Mandinari	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	UnconnectedWestern	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Soma	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	UnconnectedLower	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Barra	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over	SolarPV	BarraDemand	Candidate	2014				20	1	10	0	0	20%	100%

Generator Name	Technology	Location	Status	Year available	CAPEX $m/MW	Variable O&M cost $/MWh	Fixed O&M cost $k/MW year	Amortization time	Build time years	Max available cap	Minimum build capacity	CO2 Emissions tCO2/ MWh	Availability (%)	Thermal Efficiency MWh input/MWh output
50kW)					6.0	-	60.0							
Solar (over 50kW)	SolarPV	Kerewan	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	NjabaKunda	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Farrafenni	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	UnconnectedNorth1	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	UnconnectedNorth2	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Kaur	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Kuntaur	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Janjanburreh	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Bansang	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	UnconnectedCentral1	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	UnconnectedCentral2	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Solar (over 50kW)	SolarPV	Basse	Candidate	2014	6.0	-	60.0	20	1	10	0	0	20%	100%
Coal 125MW CFB	Coal 125MW CFB	Kotu	Candidate	2017	2.2	3.1	7.5	35	4	10000	125	0.85	85%	38%
Coal 70MW	Coal 70MW	Brikama	Candidate	2017	2.4	3.1	7.5	35	4	10000	70	0.85	85%	38%
Coal 125MW CFB	Coal 125MW CFB	Brikama	Candidate	2017	2.2	3.1	7.5	35	4	10000	125	0.85	85%	38%
Coal 125MW CFB	Coal 125MW CFB	Barra	Candidate	2017	2.2	3.1	7.5	35	4	10000	125	0.85	85%	38%
Coal 250MW PC	Coal 250MW PC	Kotu	Candidate	2017	2.2	2.7	6.5	35	4	10000	250	0.85	85%	39%
Coal 250MW PC	Coal 250MW PC	Brikama	Candidate	2017	2.2	2.7	6.5	35	4	10000	250	0.85	85%	39%
Coal 250MW PC	Coal 250MW PC	Barra	Candidate	2017	2.2	2.7	6.5	35	4	10000	250	0.85	85%	39%
Biomass 5MW grate furnace	Biomass 5MW grate furnace	Kaur	Candidate	2015	6.8	-	272.0	30	2	10000	5	0	85%	24%

Generator Name	Technology	Location	Status	Year available	CAPEX $m/MW	Variable O&M cost $/MWh	Fixed O&M cost $k/MW year	Amortization time	Build time years	Max available cap	Minimum build capacity	CO2 Emissions tCO2/MWh	Availability (%)	Thermal Efficiency MWh input/MWh output
Biomass 5MW grate furnace	Biomass 5MW grate furnace	Brikama	Candidate	2015	6.8	-	272.0	30	2	10000	5	0	85%	24%
Biomass 40MW CFB	Biomass 40MW CFB	Kaur	Candidate	2017	3.4	-	136.0	30	4	10000	40	0	85%	38%
Biomass 40MW CFB	Biomass 40MW CFB	Brikama	Candidate	2017	3.4	-	136.0	30	4	10000	40	0	85%	38%
Energy from Waste	Energy from Waste	Brikama	Candidate	2017	20.5	49.4	-	30	4	10000	40	0	85%	38%
Oil Engine	HFO new	Barra	Candidate	2014	1.4	7.1	16.8	20	2	200	20	0.595	83%	40%
Oil Engine	HFO new	Brikama	Candidate	2014	1.4	7.1	16.8	20	2	200	20	0.595	83%	40%
Oil Engine	HFO new	UnconnectedWestern	Candidate	2014	1.4	7.1	16.8	20	2	200	20	0.595	83%	40%
Oil Engine	HFO new	Farrafenni	Candidate	2014	1.4	7.1	16.8	20	2	200	20	0.595	83%	40%
Oil Engine	HFO new	Basse	Candidate	2014	1.4	7.1	16.8	20	2	200	20	0.595	83%	40%
Oil Engine	HFO new	Kotu	Candidate	2014	1.5	7.1	16.8	20	2	200	20	0.595	83%	40%
Oil Engine	HFO new	Brikama	Candidate	2014	1.5	7.1	16.8	20	2	200	20	0.595	83%	40%
Oil Engine	HFO new	UnconnectedWestern	Candidate	2014	1.5	7.1	16.8	20	2	200	20	0.595	83%	40%
Oil Engine	HFO new	Farrafenni	Candidate	2014	1.5	7.1	16.8	20	2	200	20	0.595	83%	40%
Oil Engine	HFO new	Basse	Candidate	2014	1.5	7.1	16.8	20	2	200	20	0.595	83%	40%
Oil Engine	LFO new	Brikama	Candidate	2014	1.1	10.1	8.4	20	2	200	5	0.595	83%	36%
Oil Engine	LFO new	UnconnectedWestern	Candidate	2014	1.1	10.1	8.4	20	2	200	5	0.595	83%	36%
Oil Engine	LFO new	UnconnectedLower	Candidate	2014	1.1	10.1	8.4	20	2	200	5	0.595	83%	36%
Oil Engine	LFO new	Barra	Candidate	2014	1.1	10.1	8.4	20	2	200	5	0.595	83%	36%
Oil Engine	LFO new	Kerewan	Candidate	2014	1.1	10.1	8.4	20	2	200	5	0.595	83%	36%
Oil Engine	LFO new	Farrafenni	Candidate	2014	1.1	10.1	8.4	20	2	200	5	0.595	83%	36%
Oil Engine	LFO new	UnconnectedNorth1	Candidate	2014				20	2	200	5	0.595	83%	36%

Generator Name	Technology	Location	Status	Year available	CAPEX $m/MW	Variable O&M cost $/MWh	Fixed O&M cost $k/MW year	Amortization time	Build time years	Max available cap	Minimum build capacity	CO2 Emissions tCO2/ MWh	Availability (%)	Thermal Efficiency MWh input/MWh output
					1.1	10.1	8.4							
Oil Engine	LFO new	UnconnectedNorth2	Candidate	2014	1.1	10.1	8.4	20	2	200	5	0.595	83%	36%
Oil Engine	LFO new	Kaur	Candidate	2014	1.1	10.1	8.4	20	2	200	5	0.595	83%	36%
Oil Engine	LFO new	Bansang	Candidate	2014	1.1	10.1	8.4	20	2	200	10	0.595	83%	36%
Oil Engine	LFO new	UnconnectedCentral1	Candidate	2014	1.1	10.1	8.4	20	2	200	10	0.595	83%	36%
Oil Engine	LFO new	UnconnectedCentral2	Candidate	2014	1.1	10.1	8.4	20	2	200	10	0.595	83%	36%
Oil Engine	LFO new	Basse	Candidate	2014	1.1	10.1	8.4	20	2	200	10	0.595	83%	36%
Oil Engine	LFO new	UnconnectedUpper	Candidate	2014	1.1	10.1	8.4	20	2	200	10	0.595	83%	36%
CCGT 300MW	CCGT 300MW	Kotu	Candidate	2016	1.4	5.6	31.0	25	3	10000	300	0.35	85%	52%
CCGT 300MW	CCGT 300MW	Brikama	Candidate	2016	1.4	5.6	31.0	25	3	10000	300	0.35	85%	52%
CCGT 300MW	CCGT 300MW	Barra	Candidate	2016	1.4	5.6	31.0	25	3	10000	300	0.35	85%	52%
OCGT150MW	OCGT150MW	Kotu	Candidate	2015	1.6	7.0	6.0	25	2	10000	150	0.35	85%	33%
OCGT150MW	OCGT150MW	Brikama	Candidate	2015	1.6	7.0	6.0	25	2	10000	150	0.35	85%	33%
OCGT150MW	OCGT150MW	Barra	Candidate	2015	1.6	7.0	6.0	25	2	10000	150	0.35	85%	33%

4. FUEL PRICES

Our initial assumptions for central fuel prices are based on the World Bank commodity forecast, 2012.

We used the crude oil price to derive prices for LFO and HFO. The LFO and HFO prices have been further inflated to allow for real costs to deliver to the Gambia based on fuel costs given by NAWEC.

Coal is not currently imported to the Gambia. Based on our experience, we have added a handling cost estimate of US$12/metric tonne to the World Bank forecast.

Prices for natural gas and liquefied natural gas (LNG) are included for comparison only. These fuels are not currently available in the Gambia. Coal is also not currently available, but might be shipped in (for example, from South Africa).

Figure 51 and Table 15 show our assumptions for fuel price projections. Additional information on real logistics costs in the Gambia may allow us to adjust this further.

Biomass waste costs are based on the costs of biomass pellets produced from Groundnuts in the Gambia, at 5,200 GMD/tonne. Waste fuel costs are assumed to be zero. If gating fees applied, then this would be negative.

Figure 51: Primary fuel price projections 2010-2032 ($/toe, 2011 real)
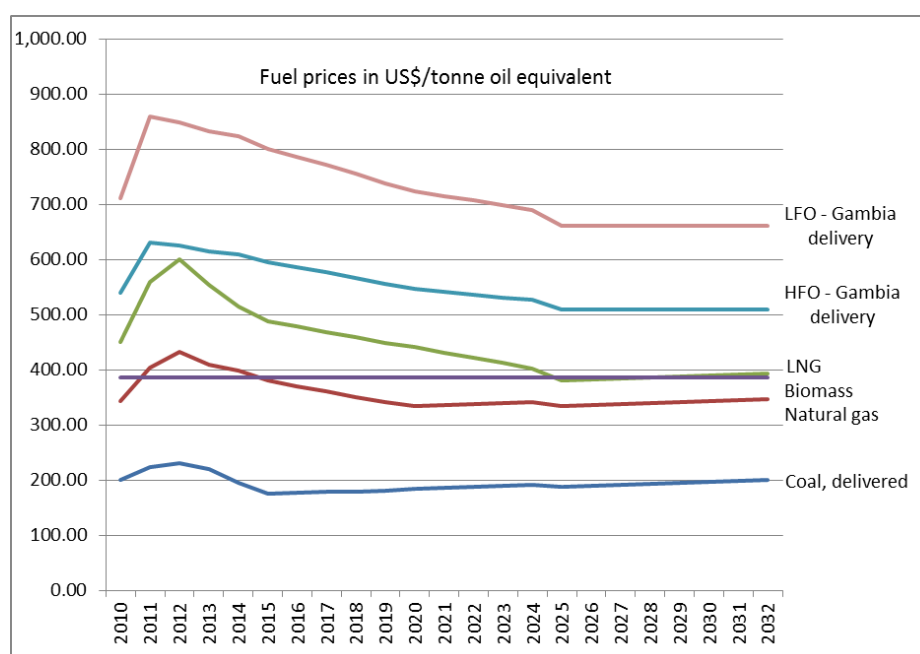
Source: AF Mercados elaboration from data

Table 17: Primary fuel price projections 2010-2032 (US$/toe, 2011 real)

	Coal ($/toe)	Natural gas ($/toe)	LNG ($/toe)	HFO Gambia delivery ($/toe)	LFO Gambia delivery ($/toe)	Biomass (groundnut shell pellets)
2010	179.75	342.69	450.65	539.23	710.79	386.02
2011	201.91	403.71	558.62	630.49	858.43	386.02
2012	209.71	431.88	600.87	624.86	849.33	386.02
2013	199.45	408.41	553.93	614.23	832.14	386.02
2014	173.43	398.44	514.36	608.60	823.03	386.02
2015	153.69	380.24	488.21	594.23	799.78	386.02
2016	155.40	370.49	478.44	586.02	786.49	386.02
2017	157.11	360.74	468.68	576.79	771.57	386.02

2018	158.81	350.99	458.92	566.55	755.00	386.02
2019	160.52	341.24	449.15	555.47	737.08	386.02
2020	163.33	333.30	441.27	547.35	723.94	386.02
2021	165.05	335.26	431.46	541.89	715.10	386.02
2022	166.77	337.22	421.65	536.65	706.62	386.02
2023	168.49	339.18	411.85	531.40	698.14	386.02
2024	170.21	341.14	402.04	526.16	689.66	386.02
2025	167.03	333.30	380.24	508.60	661.24	386.02
2026	168.70	335.20	382.14	508.60	661.24	386.02
2027	170.37	337.11	384.04	508.60	661.24	386.02
2028	172.04	339.01	385.94	508.60	661.24	386.02
2029	173.71	340.91	387.84	508.60	661.24	386.02
2030	175.38	342.82	389.75	508.60	661.24	386.02
2031	177.05	344.72	391.65	508.60	661.24	386.02
2032	178.72	346.63	393.55	508.60	661.24	386.02

5. WEIGHTED AVERAGE COST OF CAPITAL

The model requires a weighted average cost of capital (WACC) when calculating the present value of total system costs. Total system costs include operational (production and costs of unserved energy) and investment costs (generation and transmission). Therefore the WACC is applied across the entire system and asset base, not just to a particular technology or facet. There is a possibility of including an alternative WACC for technologies during the construction phase (e.g., to reflect a higher or lower risk premium associated with a particular investment type).

In this study a WACC of 7% has been suggested based on discussions with NAWEC and PURA.

We suggest using a slightly higher WACC of 10%, which may be more in line with private investor expectations.

ANNEX 3: DATA AND ASSUMPTIONS: SCENARIOS

The alternative data inputs for each of the other scenarios are set out below.

1. HIGHER FOSSIL FUEL PRICES

As previously discussed, fossil fuel prices are a significant risk factor for the Gambia. In this scenario, we use higher fossil fuel prices than the baseline assumptions.

We made a simple assumption that fuel prices are 20% higher than World Bank projections by 2020, and 40% higher than World Bank projections by 2030. The resulting fuel prices are shown in Figure 52.

Biomass prices are left unchanged, although in reality there may be some increase in the cost of processing due to the higher fossil fuel prices. It was not possible to separate out the fuel component of these costs.

Figure 52: High case fuel price projections 2010-2032 ($/toe, 2011 real)
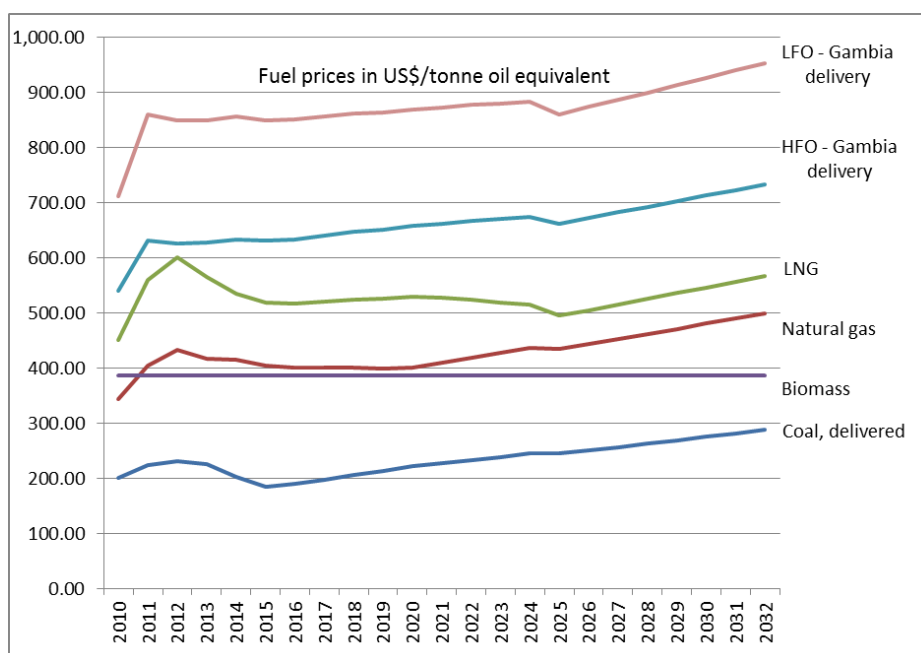
Source: AF Mercados elaboration

This scenario is intended to help test the robustness of the baseline scenario under higher fossil fuel prices. It provides an indication of how strategies might change in a higher fuel price situation.

2. INTERCONNECTION FOR JOINT HYDRO

The OMVG project includes a 225 kV interconnection simple line simple circuit crossing Guinea, Senegal, Guinea-Bissau and The Gambia to share the hydroelectric production of the sites of Kaléta and Sambangalou. The commissioning is envisaged in 2017 (WAPP 2011). The total investment for both OMVG hydro power plants (Sambagalou and Kaleta) plus 1,600 km of associated transmission lines is of the order of US$1.3 billion. Sambagalou would have an installed capacity of 128 MW and Kaleta of 240 MW. Annual production is estimated at 402 GWh/year for Sambagalou and 946 GWh/year for Kaleta.

Treating the project as a power plant on the border. The energy will be delivered to a new substation at Soma.

Table 18: Technical data for OMVG project

	Location (node)	Installed capacity MW	Max available MW	CO2 t/MWh	Load factor %	Peak %	Retire year
OMVG – overall plant	Soma	368	368	0	42%	42%	2050
OMVG – Gambia share	Soma	44.16	44.16	0	42%	42%	2050

The plan is for the project to include a 225kV connection between Brikama and Soma, but we may explore which transmission lines the model selects as optimal instead.

The project is not yet underway and involves regional negotiations. We therefore use a start date of 2020 for commercial operation (our own assumption).

Through the OMVG, The Gambia should receive from 12% of the power of the two dams. Unless alternative information is available to the Client, we assume that the Gambia will also be funding 12% of the cost of the dams.

We will consider the cost of this scenario relative to the baseline (and to the higher fossil fuel prices scenario) to analyse the relative costs and benefits.

3. RENEWABLE TARGET

In all other scenarios, the model is free to choose renewables from the basket of generation alternatives. In this scenario, the model is constrained to choose renewables up to a target.

The renewable energy target applies across the whole of the Gambia, and can be met by the lowest cost renewable source up to any constraints.

The monitoring and control on the Gambia network is currently extremely limited and would not be able to cope with large volumes of renewable electricity generation. Therefore we propose that the target to 2020 should not be too ambitious, to allow time for development of the system.

We therefore use a target of 5% of demand (MWh) met by renewables as a percentage of by 2020 and 10% of demand met by renewables by 2030.

We will consider the cost of this scenario relative to the baseline (and to the higher fossil fuel prices scenario) to analyse the relative costs and benefits.

4. PREMIUM FOR RENEWABLES IN CURRENTLY OFFGRID REGIONS

This scenario can be represented as either sufficient feed in tariff sufficient to support renewables (solar and wind) in currently offgrid regions, or as a capital grant for these technologies. Renewables in grid connected regions will not qualify for the subsidy.

The scenario will allow us to explore the options for using renewables to help achieve the Gambia's goal of full electrification more rapidly. We will consider the cost of this scenario relative to the baseline (and to the higher fossil fuel prices scenario) to analyse the relative costs and benefits.

5. FORCED TRANSMISSION INVESTMENT

As there is limited investment in transmission lines, and transmission investment would allow better balancing and sharing of capacity between regions, we chose to model a scenario where transmission investment is "forced" in the model.

Figure 53: Forced investment in transmission lines
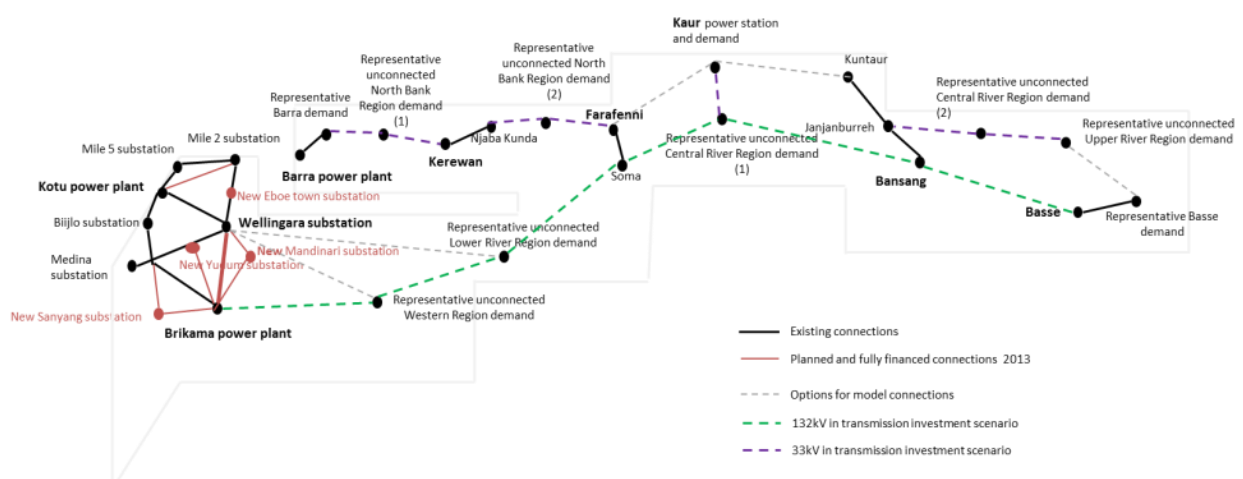
ANNEX 4: ANNUAL COSTS BY SCENARIO

		Total	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Demand (expressed) all scenarios	GWh	16,816	208	217	222	270	325	387	460	539	593	652	717	757	801	848	900	950	993	1,038	1,087	1,133	1,184	1,237	1,297
Base (coal allowed)																									
Generation	GWh	17,734	214	224	230	264	293	377	471	557	617	706	776	819	865	913	966	1,019	1,064	1,109	1,158	1,203	1,242	1,295	1,354
Renewable generation	GWh	240	0	0	0	0	2	3	4	5	6	7	8	9	10	12	13	15	15	16	17	24	24	25	25
Renewable generation	% demand	1.4%	0.0%	0.0%	0.0%	0.0%	0.7%	0.8%	0.9%	0.9%	1.0%	1.0%	1.1%	1.2%	1.3%	1.4%	1.5%	1.6%	1.5%	1.5%	1.5%	2.1%	2.1%	2.0%	1.9%
Unsupplied energy (of expressed)	GWh	207	1.6	2.0	2.2	15.2	41.7	23.7	7.0	4.3	5.6	0.1	0.4	0.7	2.7	3.7	4.9	6.3	7.6	9.6	12.1	13.5	12.1	13.9	16.3
Unsupplied energy (of expressed)	%	1.2%	0.8%	0.9%	1.0%	5.6%	12.8%	6.1%	1.5%	0.8%	0.9%	0.0%	0.1%	0.1%	0.3%	0.4%	0.5%	0.7%	0.8%	0.9%	1.1%	1.2%	1.0%	1.1%	1.3%
Generation investment	US$m (2011 real)	525	0	0	8	29	9	45	26	10	4	279	4	4	11	5	6	6	2	9	3	12	51	2	0
Transmission investment	US$m (2011 real)	33	0	0	0	0	0	4	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26
Fixed operational costs (ex. Interest)	US$m (2011 real)	74	1	1	1	2	2	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	5
Variable operational costs (inc. fuel)	US$m (2011 real)	1,724	27	32	33	37	40	51	65	77	85	56	64	67	71	76	83	87	92	98	105	110	115	122	130
Capital recovery (capital and interest)	US$m (2011 real)	782	0	0	1	4	5	10	14	15	15	46	46	47	48	49	49	50	50	51	51	53	58	59	61
Emissions	ktCO2	12,231	128	133	137	157	173	223	278	329	364	530	577	608	641	669	700	730	757	783	812	835	857	889	924
Model objective function	US$m (2011 PV)	857	29	32	36	59	58	76	58	48	45	115	28	26	27	25	25	24	23	23	21	21	22	19	18
Base (no coal)																									
Generation	GWh	17,413	214	224	230	264	306	398	475	557	615	683	751	789	834	881	934	989	1,034	1,077	1,120	1,173	1,236	1,288	1,342
Renewable generation	GWh	242	0	0	0	0	2	3	3	4	5	6	6	18	18	18	18	18	18	18	18	18	18	18	18
Renewable generation	% demand	1.4%	0.0%	0.0%	0.0%	0.0%	0.7%	0.7%	0.7%	0.8%	0.8%	0.9%	0.9%	2.3%	2.2%	2.1%	2.0%	1.9%	1.8%	1.7%	1.6%	1.6%	1.5%	1.4%	1.4%
Unsupplied energy (of expressed)	GWh	222	1.6	2.0	2.2	15.2	29.4	5.1	2.6	3.9	5.3	5.8	7.1	10.5	8.8	11.1	13.7	9.7	8.7	10.8	19.3	10.9	11.5	12.9	14.3
Unsupplied energy (of expressed)	%	1.3%	0.8%	0.9%	1.0%	5.6%	9.1%	1.3%	0.6%	0.7%	0.9%	0.9%	1.0%	1.4%	1.1%	1.3%	1.5%	1.0%	0.9%	1.0%	1.8%	1.0%	1.0%	1.0%	1.1%
Generation investment	US$m (2011 real)	384	0	0	8	29	41	35	2	3	3	36	3	20	47	0	0	33	35	6	0	52	33	0	0
Transmission investment	US$m (2011 real)	140	0	0	0	0	0	5	1	0	0	0	0	0	0	0	0	1	26	0	0	0	31	0	75
Fixed operational costs (ex. Interest)	US$m (2011 real)	86	1	1	1	2	2	3	3	3	3	3	3	4	4	4	4	4	5	5	5	5	6	6	7
Variable operational costs (inc. fuel)	US$m (2011 real)	2,169	27	32	33	37	42	55	66	77	84	89	97	100	105	110	115	118	124	129	135	142	144	151	157
Capital recovery (capital and interest)	US$m (2011 real)	537	0	0	1	4	9	13	13	14	14	18	18	20	25	25	25	29	36	37	37	42	49	49	58
Emissions	ktCO2	10,217	128	133	137	157	181	235	281	329	363	403	443	459	486	514	545	578	605	630	656	688	725	756	788
Model objective function	US$m (2011 PV)	915	29	32	36	59	75	63	42	44	44	55	42	45	49	36	34	37	37	29	28	29	26	23	22

Scenario	Metric	Unit	Total	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
High fuel cost	Generation	GWh	17,548	214	224	230	264	308	382	464	555	620	684	747	789	827	888	948	998	1,051	1,100	1,154	1,199	1,250	1,303	1,349
	Renewable generation	GWh	1,622	0	0	0	0	3	4	5	6	7	8	8	8	8	8	8	8	8	8	8	306	305	305	305	306
	Renewable generation	% demand	9.6%	0.0%	0.0%	0.0%	0.0%	1.0%	1.0%	1.0%	1.1%	1.1%	1.2%	1.1%	1.0%	0.9%	0.9%	0.8%	0.8%	0.8%	0.7%	28.2%	27.0%	25.8%	24.7%	23.6%
	Unsupplied energy (of expressed)	GWh	225	1.6	2.0	2.2	15.2	27.3	19.2	12.7	5.2	6.8	5.9	10.9	10.4	11.1	6.8	7.5	8.8	9.6	9.7	7.4	8.6	10.5	12.1	13.7
	Unsupplied energy (of expressed)	%	1.3%	0.8%	0.9%	1.0%	5.6%	8.4%	5.0%	2.8%	1.0%	1.1%	0.9%	1.5%	1.4%	1.4%	0.8%	0.8%	0.9%	1.0%	0.9%	0.7%	0.8%	0.9%	1.0%	1.1%
	Generation investment	US$m (2011 real)	512	0	0	8	29	60	16	22	10	4	10	0	0	54	33	33	0	0	35	199	0	0	0	0
	Transmission investment	US$m (2011 real)	43	0	0	0	0	0	1	0	2	1	0	1	2	1	1	1	1	0	0	0	0	0	0	31
	Fixed operational costs (ex. Interest)	US$m (2011 real)	100	1	1	1	2	2	3	3	3	3	3	3	3	3	4	4	4	4	4	10	10	9	9	10
	Variable operational costs (inc. fuel)	US$m (2011 real)	2,645	27	32	33	38	44	56	70	86	95	106	117	126	133	141	147	152	162	170	161	171	182	193	203
	Capital recovery (capital and interest)	US$m (2011 real)	603	0	0	1	4	11	13	15	16	17	18	18	18	24	28	32	32	32	36	57	57	57	57	61
	Emissions	ktCO2	9,476	128	133	137	157	181	225	273	327	365	403	440	465	488	524	559	590	621	650	504	532	562	593	620
	Model objective function	US$m (2011 PV)	1,054	29	32	36	60	89	57	60	53	50	52	50	49	60	51	48	39	38	40	46	31	30	29	28
High VOLL	Generation	GWh	17,509	214	224	230	264	329	400	474	556	613	674	751	792	837	886	940	991	1,036	1,083	1,130	1,174	1,248	1,301	1,362
	Renewable generation	GWh	96	0	0	0	0	2	3	3	4	5	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Renewable generation	% demand	0.6%	0.0%	0.0%	0.0%	0.0%	0.7%	0.7%	0.7%	0.8%	0.8%	0.9%	0.8%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%	0.4%	0.4%
	Unsupplied energy (of expressed)	GWh	130	1.6	2.0	2.2	15.2	7.0	0.9	2.2	1.7	2.7	3.5	5.2	1.9	4.6	5.0	6.3	7.5	8.6	6.4	7.7	8.9	9.0	9.5	9.9
	Unsupplied energy (of expressed)	%	0.8%	0.8%	0.9%	1.0%	5.6%	2.2%	0.2%	0.5%	0.3%	0.4%	0.5%	0.7%	0.3%	0.6%	0.6%	0.7%	0.8%	0.9%	0.6%	0.7%	0.8%	0.8%	0.8%	0.8%
	Generation investment	US$m (2011 real)	454	0	0	8	29	119	9	2	3	3	3	46	48	0	6	0	0	0	68	13	0	39	13	46
	Transmission investment	US$m (2011 real)	127	0	0	0	0	0	4	0	27	26	1	0	1	0	0	0	0	0	0	0	1	3	0	63
	Fixed operational costs (ex. Interest)	US$m (2011 real)	88	1	1	1	2	3	3	3	3	4	4	4	5	4	4	4	4	4	5	5	5	5	5	7
	Variable operational costs (inc. fuel)	US$m (2011 real)	2,204	27	32	33	37	47	56	66	77	84	92	97	102	107	112	117	120	125	131	138	144	148	155	158
	Capital recovery (capital and interest)	US$m (2011 real)	639	0	0	1	4	17	18	19	19	22	23	28	33	33	34	34	34	34	41	43	43	48	49	61
	Emissions	ktCO2	10,361	128	133	137	157	194	237	280	329	362	397	443	468	494	524	556	587	613	641	669	695	739	771	807
	Model objective function	US$m (2011 PV)	970	30	33	37	67	125	45	42	44	53	44	58	53	38	37	35	32	31	36	29	27	27	24	23
RES Target	Generation	GWh	17,268	214	224	230	264	309	389	470	555	613	672	736	778	821	870	923	973	1,016	1,073	1,121	1,166	1,219	1,286	1,345
	Renewable generation	GWh	1,143	0	0	0	0	5	7	10	16	22	29	37	43	48	55	59	63	66	106	98	108	118	124	129
	Renewable generation	% demand	6.8%	0.0%	0.0%	0.0%	0.0%	1.7%	1.7%	2.1%	2.9%	3.7%	4.4%	5.2%	5.6%	6.0%	6.5%	6.6%	6.6%	6.7%	10.2%	9.0%	9.5%	10.0%	10.0%	10.0%

		Total	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Unsupplied energy (of expressed)	GWh	226	1.6	2.0	2.2	15.2	26.1	12.4	7.2	4.3	4.8	5.7	8.3	8.0	8.7	10.0	9.1	10.6	11.2	12.4	12.1	13.5	13.3	12.7	14.3
Unsupplied energy (of expressed)	%	1.3%	0.8%	0.9%	1.0%	5.6%	8.0%	3.2%	1.6%	0.8%	0.8%	0.9%	1.2%	1.1%	1.1%	1.2%	1.0%	1.1%	1.1%	1.2%	1.1%	1.2%	1.1%	1.0%	1.1%
Generation investment	US$m (2011 real)	635	0	0	8	29	53	17	20	21	20	23	20	12	48	16	49	13	54	46	47	16	48	54	21
Transmission investment	US$m (2011 real)	90	0	0	0	0	0	5	0	0	0	0	0	27	0	0	0	0	0	0	26	0	31	0	0
Fixed operational costs (ex. Interest)	US$m (2011 real)	127	1	1	1	2	2	3	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	11	11
Variable operational costs (inc. fuel)	US$m (2011 real)	2,105	27	32	33	37	42	53	64	75	81	88	95	99	104	108	114	116	121	124	127	133	139	143	149
Capital recovery (capital and interest)	US$m (2011 real)	757	0	0	1	4	10	12	15	17	19	22	24	28	33	35	41	42	48	53	61	63	72	78	80
Emissions	ktCO2	9,594	128	133	137	157	181	228	274	321	352	382	416	438	460	485	514	542	565	575	609	630	655	692	723
Model objective function	US$m (2011 PV)	960	29	32	36	59	83	54	52	52	51	50	48	49	50	39	43	34	37	33	32	26	27	24	21
Offgrid FIT																									
Generation	GWh	17,369	214	224	230	264	328	396	466	553	612	672	738	777	820	876	935	986	1,035	1,081	1,124	1,179	1,231	1,284	1,345
Renewable generation	GWh	943	0	0	0	0	15	35	44	48	50	53	53	53	53	53	53	53	53	53	55	55	55	54	55
Renewable generation	% demand	5.6%	0.0%	0.0%	0.0%	0.0%	4.7%	9.0%	9.6%	9.0%	8.5%	8.1%	7.4%	7.0%	6.6%	6.2%	5.9%	5.6%	5.3%	5.1%	5.0%	4.8%	4.6%	4.4%	4.2%
Unsupplied energy (of expressed)	GWh	206	1.6	2.0	2.2	15.2	8.0	4.5	9.3	5.0	4.9	6.0	8.1	11.9	11.2	12.5	9.9	10.6	9.4	9.6	15.3	11.5	11.4	13.0	12.9
Unsupplied energy (of expressed)	%	1.2%	0.8%	0.9%	1.0%	5.6%	2.5%	1.2%	2.0%	0.9%	0.8%	0.9%	1.1%	1.6%	1.4%	1.5%	1.1%	1.1%	0.9%	0.9%	1.4%	1.0%	1.0%	1.0%	1.0%
Generation investment	US$m (2011 real)	482	0	0	8	29	74	42	24	21	11	6	6	0	48	33	0	6	33	35	6	33	35	0	33
Transmission investment	US$m (2011 real)	67	0	0	0	0	0	2	1	3	2	1	0	0	0	0	1	0	0	0	26	31	0	0	0
Fixed operational costs (ex. Interest)	US$m (2011 real)	124	1	1	1	2	3	4	5	5	5	6	6	6	6	6	6	6	7	7	7	8	8	8	9
Variable operational costs (inc. fuel)	US$m (2011 real)	1,943	27	32	33	37	42	45	52	62	70	77	85	90	95	97	104	108	112	118	122	125	131	138	143
Capital recovery (capital and interest)	US$m (2011 real)	658	0	0	1	4	12	17	20	22	23	24	25	25	30	34	34	35	38	42	46	53	57	57	60
Emissions	ktCO2	9,773	128	133	137	157	186	215	251	300	334	368	408	431	456	490	525	555	584	611	636	669	700	731	768
Spend on FIT	*US$m (2011 real)*	*148*	*0*	*0*	*0*	*0*	*2*	*5*	*7*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*9*	*9*	*9*	*9*
Model objective function (excl. FIT)	US$m (2011 PV)	891	29	32	36	59	88	61	50	48	42	40	40	37	47	40	31	30	32	30	28	27	24	21	20
OMVG (no coal)																									
Generation	GWh	17,837	214	224	230	264	315	395	461	557	615	676	788	828	883	934	973	1,022	1,065	1,100	1,161	1,206	1,261	1,309	1,360
Renewable generation	GWh	5,230	0	0	0	0	2	3	4	5	6	7	394	394	396	397	400	400	401	401	403	403	404	404	405
Renewable generation	% demand	31.1%	0.0%	0.0%	0.0%	0.0%	0.7%	0.8%	0.9%	0.9%	1.0%	1.0%	55.0%	52.1%	49.4%	46.8%	44.4%	42.1%	40.4%	38.7%	37.1%	35.6%	34.1%	32.6%	31.2%
Unsupplied energy (of expressed)	GWh	215	1.6	2.0	2.2	15.2	20.8	8.5	16.5	3.9	5.3	6.9	3.4	4.6	7.7	9.0	8.1	9.6	10.7	11.1	11.5	12.9	12.7	14.5	16.9
Unsupplied energy (of expressed)	%	1.3%	0.8%	0.9%	1.0%	5.6%	6.4%	2.2%	3.6%	0.7%	0.9%	1.1%	0.5%	0.6%	1.0%	1.1%	0.9%	1.0%	1.1%	1.1%	1.1%	1.1%	1.1%	1.2%	1.3%

		Total	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Generation investment	US$m (2011 real)	**340**	0	0	8	29	55	3	3	23	4	4	34	4	5	5	41	6	2	38	35	3	38	2	0
Transmission investment	US$m (2011 real)	**225**	0	0	0	0	0	6	1	0	0	0	64	0	0	1	0	0	26	26	31	0	0	69	0
Fixed operational costs (ex. Interest)	US$m (2011 real)	**91**	1	1	1	2	2	3	3	3	3	3	4	4	4	4	4	4	5	5	6	6	6	8	8
Variable operational costs (inc. fuel)	US$m (2011 real)	**1,616**	27	32	33	37	44	54	63	77	84	92	54	59	65	69	74	78	82	85	90	96	101	107	114
Capital recovery (capital and interest)	US$m (2011 real)	**607**	0	0	1	4	10	11	11	14	14	15	26	26	27	27	32	32	36	43	50	50	54	62	62
Emissions	ktCO2	**7,502**	128	133	137	157	186	233	272	328	362	398	234	258	290	319	341	370	395	415	451	478	510	538	568
Model objective function	US$m (2011 PV)	**794**	29	32	36	59	82	45	47	54	44	44	50	25	25	25	30	22	24	26	24	19	19	19	17
OMVG (with coal)																										
Generation	GWh	**18,343**	214	224	230	264	294	393	464	580	637	708	823	866	924	966	1,014	1,063	1,105	1,148	1,188	1,238	1,284	1,329	1,387
Renewable generation	GWh	**4,931**	0	0	0	0	1	1	1	1	1	1	329	339	387	387	388	387	387	387	388	387	387	386	388
Renewable generation	% demand	**29.3%**	0.0%	0.0%	0.0%	0.0%	0.4%	0.3%	0.3%	0.2%	0.2%	0.2%	45.9%	44.8%	48.2%	45.6%	43.1%	40.7%	38.9%	37.3%	35.7%	34.1%	32.6%	31.2%	29.9%
Unsupplied energy (of expressed)	GWh	**183**	1.6	2.0	2.2	15.2	40.4	12.0	18.5	6.9	9.3	2.4	0.0	0.0	1.1	2.2	3.6	5.0	6.3	8.9	11.3	10.6	9.1	6.2	7.7
Unsupplied energy (of expressed)	%	**1.1%**	0.8%	0.9%	1.0%	5.6%	12.5%	3.1%	4.0%	1.3%	1.6%	0.4%	0.0%	0.0%	0.1%	0.3%	0.4%	0.5%	0.6%	0.9%	1.0%	0.9%	0.8%	0.5%	0.6%
Generation investment	US$m (2011 real)	**606**	0	0	8	29	11	46	0	249	0	0	30	0	0	0	0	0	0	0	0	33	68	100	33
Transmission investment	US$m (2011 real)	**134**	0	0	0	0	0	4	0	2	0	28	40	0	10	0	0	0	0	1	47	0	0	0	0
Fixed operational costs (ex. Interest)	US$m (2011 real)	**86**	1	1	1	2	2	3	3	3	3	4	4	4	4	4	4	4	4	4	5	5	6	7	7
Variable operational costs (inc. fuel)	US$m (2011 real)	**1,084**	27	32	33	37	41	54	63	43	49	57	25	28	27	33	38	43	48	54	58	65	70	76	82
Capital recovery (capital and interest)	US$m (2011 real)	**890**	0	0	1	4	5	11	11	38	38	41	49	49	50	50	50	50	50	50	56	59	67	78	81
Emissions	ktCO2	**10,013**	128	133	137	157	174	233	275	447	487	534	414	439	452	478	506	535	560	586	610	640	667	694	728
Model objective function	US$m (2011 PV)	**711**	29	32	36	59	59	72	46	128	28	35	30	11	13	11	12	12	13	13	16	15	15	15	12
Transmission																										
Generation	GWh	**19,508**	214	224	230	264	315	385	452	632	701	776	857	905	952	998	1,055	1,113	1,163	1,238	1,295	1,347	1,405	1,467	1,518
Renewable generation	GWh	**22**	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Renewable generation	% demand	**0.1%**	0.0%	0.0%	0.0%	0.0%	0.4%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Unsupplied energy (of expressed)	GWh	**143**	1.6	2.0	2.2	15.2	20.2	16.6	25.0	0.0	0.0	0.0	0.0	0.0	1.3	2.5	3.8	5.2	6.4	2.6	4.7	6.0	8.0	9.6	10.6
Unsupplied energy (of expressed)	%	**0.9%**	0.8%	0.9%	1.0%	5.6%	6.2%	4.3%	5.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.3%	0.4%	0.5%	0.6%	0.2%	0.4%	0.5%	0.7%	0.8%	0.8%
Generation investment	US$m (2011 real)	**729**	0	0	8	29	37	13	0	394	0	0	0	0	0	0	0	0	243	0	0	0	0	0	6
Transmission investment	US$m (2011 real)	**189**	0	0	0	0	0	1	0	187	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
Fixed operational costs (ex. Interest)	US$m (2011 real)	**113**	1	1	1	2	2	2	2	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6

		Total	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Variable operational costs (inc. fuel)	US$m (2011 real)	**1,169**	27	32	33	37	45	56	66	28	31	35	40	42	46	52	59	65	71	59	62	65	69	72	79
Capital recovery (capital and interest)	US$m (2011 real)	**1,370**	0	0	1	4	8	10	10	74	74	74	74	74	74	74	74	74	74	100	100	100	100	100	101
Emissions	ktCO2	**15,835**	128	133	137	157	187	228	268	535	594	656	725	765	803	831	865	899	929	1,049	1,098	1,142	1,189	1,243	1,274
Model objective function	US$m (2011 PV)	**829**	29	32	36	59	69	53	50	249	18	18	18	17	17	17	18	18	18	34	13	12	12	12	12

ANNEX 5: ATTENDEES AT WORKSHOP AND SCHEDULE

Invitees

Solicitor General and Legal Secretary, AG Chambers and Ministry of Justice

Permanent Secretary, Ministry of Finance and Economic Affairs

Permanent Secretary, Ministry of Forestry and Environment

Permanent Secretary, Ministry of Trade, Industry, Regional Integration & Employment

Permanent Secretary, Ministry of Agriculture

Charge D'Affaires, EU Delegation in the Gambia

Managing Director, National Water and Electricity Company

Executive Secretary, Gambia Competition Commission

Director, Gambia Standards Bureau

Executive Director, National Environment Agency

Director General, Public Utilities Regulatory Authority

Director, National Agricultural Research Institute

Vice Chancellor, University of the Gambia

Lord Mayor, Banjul City Council

Lord Mayor, Kanifing Municipal Council

Governor, West Coast Region

Governor, Lower River Region

Governor, North Bank Region

Governor, Central River Region

Governor, Upper River Region

Chairman, REAGAM

Managing Director, Global Electric Group

Aldwych International

CEO, Gambia Chamber of Commerce and Industry

President, Gambia Hotel Association

President, Association of Gambian Manufacturers

Managing Director, Guaranty Trust Bank

Managing Director, Skye Bank

Managing Director, EcoBank

Managing Director, Zenith Bank

Managing Director, Sahel Bank

Managing Director, Gamcel

Managing Director, Africell

Managing Director, QCell

Managing Director, Comium

Managing Director, GAMTEL

Manager, Gamwind

Manager, Mbolo,

Manager, Gamsolar
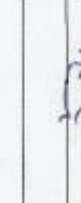
MINISTRY OF ENERGY

ELECTRICITY STRATEGY AND ACTION PLAN WORKSHOP FOR THE EUEI –PDF PROJECT

DATE: 5TH JULY, 2012
VENEU: PARADISE SUITS HOTEL.

FARE REFUND

NO	NAME	INSTITUTION	TEL	AMOUNT	SIGNATURE
1	Ousman Jarju	M o E	6718973	D400	
2	Ebrima Darry	M o E	7065145	D400	
3	Lang Sebally	NAWEC	996 4023	D400	
4	Ebou Badfe	MoE	7744866	D400	
5	Hasum Sawaneh	Commun	6608501	D400	
6	Lasana Vatts	MoE	7704241	D400	
7	Mariana King	MoE	9901429	D400	
8	Seedy Jammeh	MoE	7390246	D400	
9	Kemo K. Ceesay	MoE	7993070	D400	
10	Salmma Suso	NEA NAWEC	7886046	D400	
11	Hawcel Flan	NAWEC	9964093	D400	
12	Yusupha Joof	Pub-A	7823777	D400	
13	Baleny Kantel	NAWEC	9964088	D400	
14	Bifeny Sannel	CFFL	9817371	D400	
15	Depman Njie	NAWEC	9973356	D400	
16	Alhagi E. Cho	NAWEC	9963057	D400	

NO	NAME	INSTITUTION	TEL	AMOUNT	SIGNATURE
17	Demba Jallow	NAWEC	9862607	D400	
18	Ngoso Campbell	PURA	9933057	D400	
19	Fatrima Ceesay	PURA	7060372	D400	
20	Mamudu Ceesai	Governors office WCR	9832928	D400	
21	Kemesing Tranelle	NAWEC	9407784	D400	
22	Yaffa Manneh	GAMCEL	9961127	D400	
23	Bonou Sibye Ceesay	GCC	7814265	D400	
24	Lawela Baldye	NEA	9976093	D400	
25	Modou Manneh	MOE	9835172	D400	
26	Edrisa Jarjo	NAWEC	9960634	D400	
27	Adama Cham	GCC	6357435	D400	
28	Maryang Njie	MOFEN	6153876	D400	
29	Adama Hassana	MOE	6915-3317	D400	
30	Omar S Deh	NEA	8057796	D400	
31	Alex Ot Cosm	UNDP	3337 P282	D400	
32	Musa J. Marku	AFRITECH	7250103	D400	

NO	NAME	INSTITUTION	TEL	AMOUNT	SIGNATURE
33	Paul Mendy	MoE	3772202	D400	
34	Hamdou Dioulos	AFRiTen	725,1399	D400	
35	Oshise Ball Dankes	CAFDA	9856622	D400	
36	Suleayman Ceange	MoERa	9712581.1	D400	
37	PETER D. MENDy	MOE	9832357	D400	
38	Mamma Nyang	DPS (MoE)	9962231	D400	
39	Bai Boden Jallow	TASK	9996608	D400	
40	Ibrahim F. kinteh	Gam-Solar	9928618	D400	
41	Tumba Bah	Daily news	6965420	D400	
42	Jaingba manjang	The VOICE	3629130	D400	
43	Edrissa kanjoorg	MoE	9826331	D400	
44	Ousman Bourtel	Sahel Invest	7516959	D400	
45	Pabtos Jammel	MOTIE	9790689	D400	
46	Lamfou Sanglia	DOLS	3944046	D400	
47	CHNS BAH	kshAM	978883	D400	
48	Everest Garba	Africel	7750072	D400	

O	NAME	INSTITUTION	TEL	AMOUNT	SIGNATURE
49			9917210	D400	
50	OUSMAN NJINTEH	Mog	7615...	D400	
51				D400	
52				D400	
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64				D400	

Program Schedule

Thursday 5 July 2012 at Paradise Suites Hotel

Time	Activities
09:00 - 09:30	Registration of participants
09:30 - 11:00	**PART A: SCENARIO ANALYSIS**
09:30 – 09:40	Welcome from Ministry of Energy,
09:40 - 09:50	Brief overview of project objectives and progress to date by Alice Waltham, AF-Mercados
09:50 - 10:30	Model approach, scenarios and results, Daniel Serrano, AF-Mercados
10:30 - 11:00	**Discussion 1** – Questions and debate on the scenario results led by Alice Waltham
11:00 - 11.30	**Coffee/Tea Break**
11:30 - 13:30	**PART B: ACTION AND INVESTMENT PLAN**
11:30 - 12:00	Our recommendation for a high level investment plan as a result of the scenario results, Daniel Serrano
12:00 - 12:45	Challenges that need to be addressed and strategy to deliver required investment, Alice Waltham
12:45 - 13:30	**Discussion 2** – Questions and debate on the investment plan and strategy, led by Alice Waltham
13:15 - 13:30	Closing Remarks by Kemo Ceesay, Director of Energy, Ministry of Energy
13:30	**Close and lunch**

ANNEX 6: REFERENCES

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Currency conversions used

1 US$ = 29.69 GMD

1 US$ = € 0.7843