ELECTRICITY REGULATORY AUTHORITY

THE LEAST COST GENERATION PLAN

2016 – 2025

EXECUTIVE SUMMARY

In 2013, the Authority developed a 5 year Least Cost Generation Plan (LCGP) that covered the period 2013 to 2018. An update of the LCGP has been undertaken covering a 10 year period of 2016 to 2025. The update involved review of the load forecast in light of changed parameters, commissioning dates for committed projects, costs of generation plants, transmission and distribution system investment requirements.

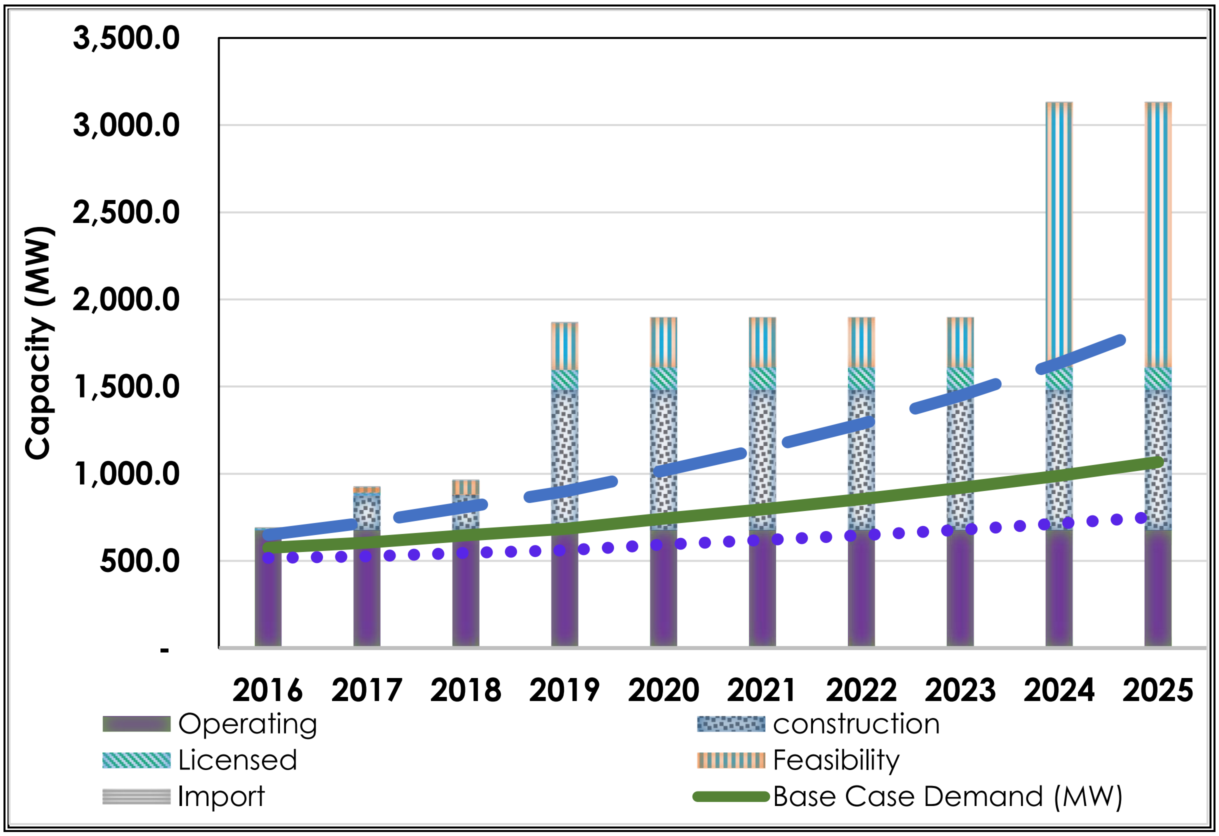
In the update of the plan, similar to the Power Sector Investment Plan, prepared by the Ministry of Energy and Mineral Development, the "**Econometric Demand**" forecasting method was used at distribution level to forecast Commercial, Medium Industry and Large Industry customer category demand. A bottom up approach was used for Domestic customer category using the end-user method. A Base Case, Low Case and High Case scenario were developed for sensitivity analysis.

The resultant demand forecast was 6.5%, 3.6% and 12% growth rate in energy demand for the Base Case, Low Case and High Case scenarios respectively. This growth rate is lower than the projection in the 2013 LCGP of 10%, 5% and 14% for Base Case, Low Case and High Case respectively.

A number of energy supply options were considered including Hydro, Peat, Solar PV, Bagasse Cogeneration, Wind and Natural Gas. The planned supply considered already existing, committed and candidate generation plants/projects with their estimated commissioning dates aligned. We note that more than 80% of the generation will come from hydro.

In the demand supply balance, ***Figure E1*** shows the demand and supply balance over the planning period. A large unutilized generation capacity is observed for the Base, Low and High Case scenarios. The excess capacity increased from about 120 MW in 2016, to a range of 1,200 MW and 2,300 MW in 2025, for the Low Case to the High Case Scenario.

***Figure E1*: Trend of Peak Demand and Supply Balance 2015 - 2024**



Source: ERA

Given the projected excess generation, there is need for a concerted effort to stimulate demand either within the country or explore options of exporting power to the neighboring countries like Rwanda, Democratic Republic of Congo and South Sudan.

In order to increase the demand, there is need for Investment in the distribution and transmission systems, to improve the quality of service and supply especially for industrial consumers to absorb the expected additional generation. This can be done through reduction of network congestion and grid extension to increase the uptake.

Policy makers may also need to explore possibilities of rescheduling the construction of some large generation plants to avoid redundant capacity. In the same vein, a review of the Energy Policies is important to align the recent developments with the Policy Direction for the electricity generation. Further, there is need to fast track the implementation of the **Rural Electrification Strategy and Plan (RESP 2013-2022),** to increase connections of rural consumers. This will facilitate the uptake of power on the national grid.

The required investment is subdivided into the distribution and transmission infrastructure. Over the next 10 years, it is estimated that USD 1.27 Billion and USD 1.2 Billion will be needed for transmission and distribution respectively. This is in addition to the required funding for implementation of the RESP.

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1. INTRODUCTION

1.1 Background

Clean energy in general and electricity in particular is an essential input in the growth and economic, social and political development of a country. Electricity is the engine of socio-economic transformation at individual household and firm level as well as at aggregate national level. As a critical input in the development process, electricity consumption has multiplier effects on the economy. The availability or lack of adequate and reliable electricity supply therefore has significant implications on the political stability of the country.

For a country to have adequate and reliable electricity supply match demand, it calls for a deliberate effort to plan and develop the electricity generation capacity of the country, based primarily on national natural resources. This is the fundamental reason why most countries develop and continually update what is generally termed as the "**Electricity Generation Plan or Least Cost Electricity Generation Plan"** in particular.

Most of the time, the reality does not conform to the plan due to a variety of factors that affect the strict implementation of plans. As such, the "**Electricity Generation Plan"** is a living document that is continuously revised to ensure that it is realistic and guides generation capacity development.

In Uganda, there has been concerted effort to develop and update the electricity related plans. In 2010, Government of Uganda (GoU) developed and published a comprehensive "**Power Sector Investment Plan"** covering up to 2035. Since then, other studies have been conducted like "**Grid Development Plan"**, by Uganda Electricity Transmission Company Limited (UETCL), Regional Power System Master

Plan and Grid Code Study by JICA, a study on Integrating Nuclear Power in Generation Capacity Plan by MEMD among others.

In 2013, the Electricity Regulatory Authority (ERA), developed a "**Least Cost Generation Plan" (LCGP)** in line with its functions as stipulated in the Electricity Act 1999, "To advise the Minister responsible for energy on the least cost projects". This Plan was shared with players in the electricity sub-sector including MEMD, UETCL and the Ministry of Finance, Planning and Economic Development (MoFPED).

The purpose of the "**Least Cost Generation Plan" (LCGP**) was to derive forward looking least cost electricity supply options that can satisfy the projected demand over a given time. The Authority intended to continuously update this plan every year in order to reflect any changes since the last LCGP was produced.

While deriving the (2013 - 2018) Plan, a number of assumptions were made on the forecast of demand and the estimated commissioning dates of the generation plants as a basis for the Plan. In light of the latest actual system demand and generation reported by UETCL for the year 2013, 2014 and 2015, this sought to review the assumptions and revise any changes that have taken place in the electricity industry since January 2013, when the last LCGP was developed. It is against this background that further, a new 10 year "**Least Cost Generation Plan"** from 2016 to 2025 was developed.

1.2 Objectives of the Plan

The overall objective of this Plan is to update the current 5-year (2013-2018) LCGP to a ten-year (2016 – 2025) Plan. The specific objectives are to:

a) Review the performance of the "**Power Sector Investment Plan"**

(PSIP) demand forecast models against the actual outturn and adapt and apply the models in forecasting demand in this report;

b) Revise and update the commissioning dates for planned generation, transmission and distribution projects and revise the 10-year electricity supply position;

c) Determine the 10-year electricity demand-supply balance position of the country;

d) Propose options to increase electricity demand in the country.

1.3 Structure of the Report

The foregoing section of this report has been the background, highlighting the importance of least cost generation planning in the Electricity Supply Industry (ESI) and the need for continuous update of the plan. The next sections of this report cover the following:

- Section 2 gives an update of the current state of Uganda's ESI including the policies, laws and regulations and market structure upon which the industry is running. Section 2 also describes the macro-economic conditions prevailing in the country, which affect the ESI.

- Section 3 of the report presents the methodology and data used in forecasting demand.

- Section 4 presents the demand forecasting.

- Section 5 presents the projected electricity supply sources and output in the 10 years.

- Section 6 presents the demand-supply balance.
- Section 7 presents the recommended options to increase demand to match the potential surplus capacity.

2. CURRENT STATUS OF UGANDA'S ELECTRICITY SUPPLY INDUSTRY

2.1. Update on Electricity Industry Policies and Reports

A review of various electricity industry related policies, Authority decisions and international activity related to electricity industry in Uganda was conducted. This was intended to inform any changes that could have affected the plan during the review period as well as the new plan moving forward as discussed in the next section.

2.1.1. Energy Policy and Renewable Energy Policy

In 2002, the Government of Uganda (GoU), developed its comprehensive Policy on Energy. The Energy Policy was defined as the '**Manner in which a given entity has decided to address issues of energy development including energy production, distribution and consumption".** The objectives of the Energy Policy were to;

- Establish the availability, potential and demand of the various energy resources in the country;
- Increase access to modern affordable and reliable energy services as a contribution to poverty eradication;
- Improve energy governance and administration;
- Stimulate economic development;

- Manage energy-related environmental impacts In addition to the **2007 Renewable Energy Policy**, developed by the Ministry of Energy.

The main objective of this policy was to increase the use of modern renewable energy so that its proportionate use increases from the then 3.8% to 61% of the total energy consumption by the year 2016. The key objectives in this policy include:

- To Maintain and improve the responsiveness of the legal and institutional framework to promote renewable energy investments;

- To establish an appropriate financing and fiscal policy framework for investments in renewable energy technologies;

- To promote research and development, international cooperation, technology transfer and adoption of standards in renewable energy technologies;

- To utilize biomass energy efficiently so as to contribute to the management of the resource in a sustainable manner;

- To promote the sustainable production and utilization of biofuels; and;

- To promote the conversion of municipal and industrial waste to energy.

Since January 2013, when the last LCGP was developed, no amendment has been made on these policies. The framework in which these policies were drawn has been considered to be the same.

2.1.2. Rural Electrification Strategy and Plan (RESP) 2013-2022

In July 2013, the Cabinet of Uganda approved the new RESP 2013 - 2022. The overall objective of this plan was and is still, "To position the electrification development program on a path that will progressively advance towards achievement of universal electrification by the year 2040, consistent with the existing policy of the Government, while ensuring the displacement of kerosene lighting in all rural Ugandan homes by 2030".

The plan targets to achieve 26% rural electrification rate (i.e. consumers who will be utilizing electricity in their homes, businesses or institutions) by 2022 from the current 7%. This is planned to be achieved using long-range service territory plans and financial forecasts for the service territories under logical, sequential allocation of investment and capacity-building resources. This will be met by electricity service expansion of up to 1.28 million on grid new service connections and 140,000 additional installations of Solar PV Systems and Mini-Grid Distribution Service Connections for off-grids making a total of 1.42 million connections[1]. If this plan is achieved, then demand for energy should be projected to increase in similar measures for our study. The implementation of this plan will contribute to the demand for electricity in the next 10 years and must therefore be considered in this LCGP.

2.2. Regulatory Policies and Decisions

2.2.1. Solar Tendering

The Authority, in a bid to manage the challenges of the intermittent power from Solar PV generation, resolved to allow developers from Solar PV supplying to the national grid to acquire licenses by going through a competitive bidding process. This was intended to give an equal

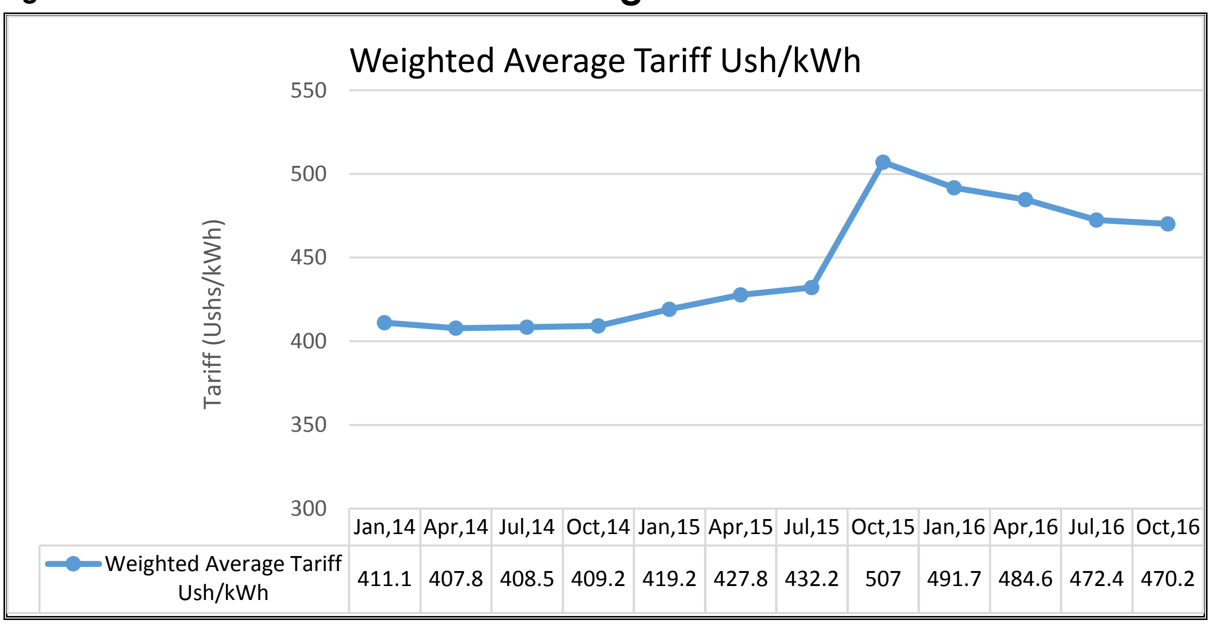
[1] Refer to the Rural Electrification Strategy and plan 2013-2022

opportunity to all developers as well as manage the capacity requirement at the time of day when they cannot generate.

2.2.2. Implementation of the Quarterly Tariff Adjustment

In 2014, the Authority approved a Quarterly Tariff Review Methodology to be used in the computation of the tariff adjustments on a quarterly basis. This adjustment was intended to recover or pay costs for fuel cost charges, foreign exchange rate fluctuation adjustment, and an inflation adjustment. ***Figure 1*** shows a trend of movement in weighted tariffs from 2014 Quarter One (Q1) to 2016 Quarter Four (Q4). A tariff increase was observed from 2014 up to Q4 2015. This increase was mainly attributed to depreciation of the Uganda shilling against other foreign currencies. The situation however improved in 2016 and a reduction is observed.

***Figure 1*: Trend of End-User Tariff Changes**



Source: ERA

2.2.3. Multi Year Tariff (MYT)

In January 2014, the Authority completed the review of UETCL's application and approved a multiyear tariff trajectory from 2014 to 2016. ERA consequently amended and issued a License to UETCL. The performance target trajectory set for the company is shown in ***Table 1*** below.

Table 1: **Loss Targets Set for UETCL**

Parameter	2014	2015	2016
Power loss (%)	4.7	4.4	4.0
Energy loss (%)	3.8	3.6	3.3

Source: ERA

These targets have been included in the tariff determination for UETCL since 2014. The process of setting another set of performance targets for UETCL starting from 2017 is underway.

2.2.4. Umeme Performance Targets

In 2012, the Authority reviewed and approved Umeme's performance targets for seven years from 2012 to 2018, as shown in ***Table 2.*** Among the parameters are; Distribution Losses, Collection Rate, Distribution Operation and Maintenance Costs (DOMC). These performance targets are being implemented by ERA as approved by the Authority.

Table 2: **Umeme Performance Targets**

PARAMETER	SYMBOL	TARIFF YEAR					
		2013	2014	2015	2016	2017	2018
DOMC(Total)	USD*1000	44,093	44,553	46,186	47,678	49,300	51,100
Uncollected Debt Factors	TUCF	2.70%	2.50%	2.30%	2.10%	1.80%	1.50%

PARAMETER	SYMBOL	TARIFF YEAR					
Loss target	LF	23.00%	20.00%	18.30%	16.90%	15.70%	14.70%
Actual Losses	ALF	24.3%	21.3%	19.5%			

Source: ERA

2.2.5. Progress of GETFiT Implementation

The Global Energy Transfer for Feed–in–Tariffs (GET-FiT)[2] Program was launched in 2013, to fast track the development of on grid small renewable energy projects which generate less than 20 MW. Since the launch of the GET-FiT Program on 24th March 2013, 4 rounds of Request for Proposals (RFP) have been successfully completed. The GETFiT Program Investment Committee approved 16 projects, with a combined generation capacity of 144.2 MW. The approved projects comprise of 2 Solar-PV projects totaling up to 20 MW, Hydro projects totaling up to 104.2 MW and Bagasse projects totaling up to 20 MW.

2.2.6. Implementation of the Demand Side Management Strategies

In 2014, ERA in an effort to manage the demand in the industry and avoid load shedding or significantly dispatching the expensive thermal plants, undertook to adjust the Time of Use Weighting Factors and distribution of energy saving bulbs as below:

a. In the 2014/15 Annual Tariff Review, the Peak Time of Use Weighting factor was increased from 110% to 130%. This was intended to shift consumption especially for time of use customers like manufacturers from consuming energy at peak time to other time periods like shoulder and off-peak periods. The effects of the consumer response so far to the shift in time of use factor was

[2] Read : http://www.getfit-uganda.org/

analyzed and it showed that there was a possible shift consumption from peak to shoulder and off-Peak time periods.

b. The Authority considered and approved the distribution of 840,000 Light Emitting Diodes (LED) as a Demand Side Management Strategy. By December 2015, 420,022 bulbs had been distributed. Another batch of 310,000 bulbs was distributed in May 2016.

2.3. Macro economy

Uganda's Electricity supply Industry (ESI) is highly affected by the prevailing macroeconomic conditions in the economy.
Uganda's electricity tariff adjustment methodology provides for quarterly adjustment of licensees' operation costs and electricity retail/end-user tariffs for changes in macro-economic parameters that affect operation costs yet are beyond the control of the industry service providers. These macro-economic parameters are:

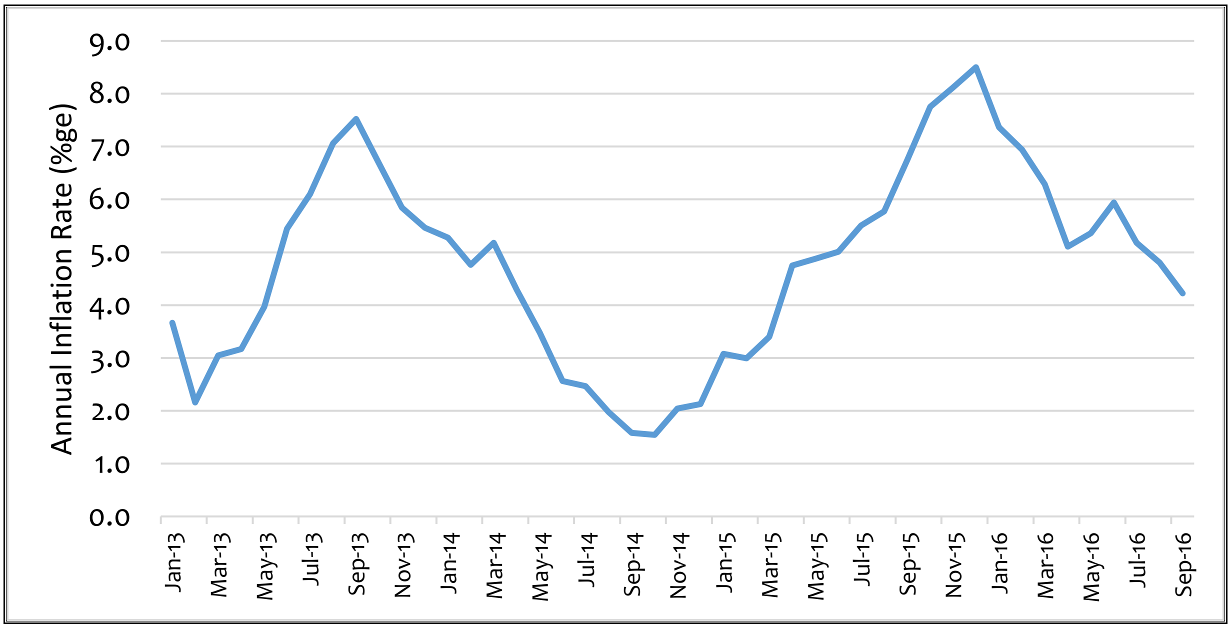
I. inflation –both local and international inflation linked to the sources of imported inputs;

II. Exchange rate and international prices of heavy fuel oil (HFO) which is used in some thermal power generation plants in Uganda.

2.3.1. Annual Inflation Rate

The inflation rate measures the movement in the general price level of good and services over the past twelve months. While determining electricity costs for various licensed companies, there is an allowance for a proportion of costs to be adjusted for movement in the variable cost of the company. This adjustment filters through to the final consumer tariff. It is therefore important to keep track of inflation in the country. ***Figure 2*** shows the trend of inflation over the past three years. For the past three years, core annual inflation has increased by an average of 5%. The lowest annualized increase in inflation (1.6%) was recorded in September 2014, while the highest annualized increase in inflation (8.5%) was in December 2015. Over the forecasting period, we expect the general price level to increase by an average of 5% per annum in line with the past trend.

Figure 2: Trend of Annualized Inflation Rate



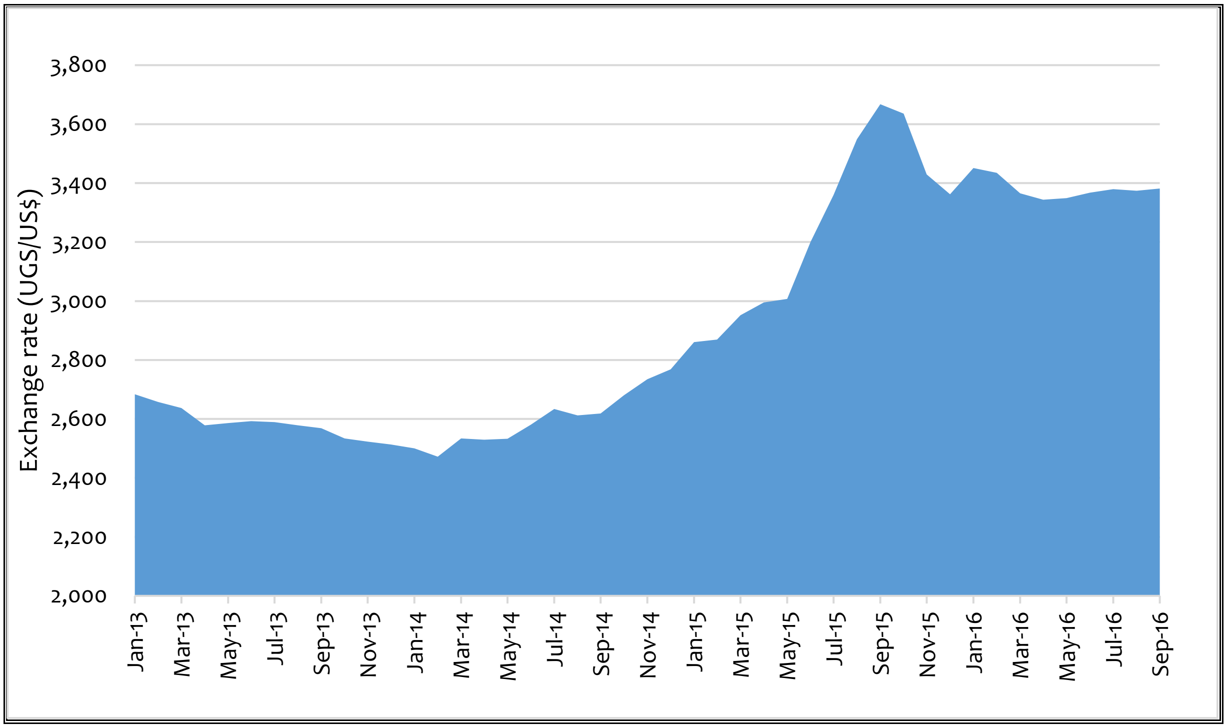
Source: Uganda Bureau of Statistics

2.4. Exchange Rate

Over 70% of Uganda's ESI costs are denominated in foreign currency – the US Dollar. A depreciation or appreciation of the Uganda shilling against the US dollar has significant implications on industry costs and end-user electricity tariffs. It is therefore important to keep track of the US Dollar against the Uganda shilling exchange rate movements.

Figure 3 shows the trend of US dollar against the Uganda shilling exchange rate over the past three years. The figure indicates that over the past three years, Uganda's shilling has generally depreciated against the US dollar by an average of 12% per annum. The most significant depreciation was noted in May 2015 to September 2015.

Figure 3: **Trend of US Dollar against the Uganda Shilling Exchange Rate**



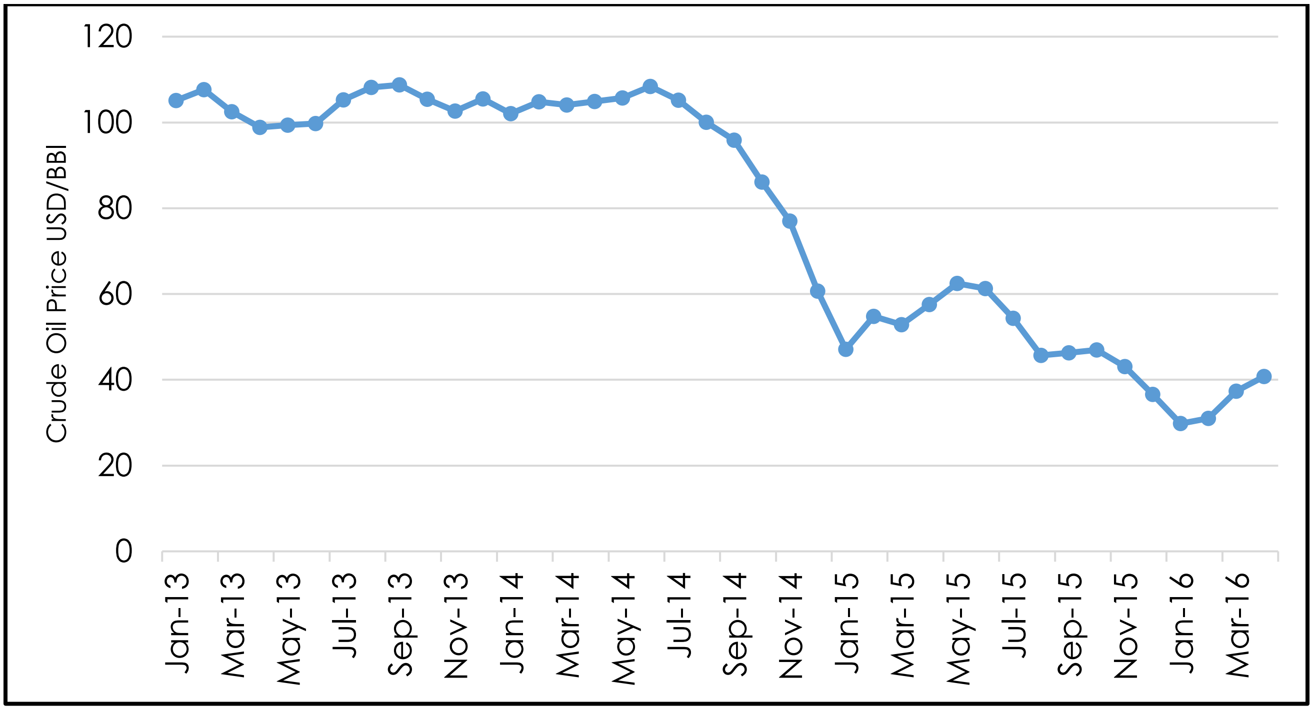
Source: ***Bank of Uganda***

Over the forecasting period, we expect the Uganda shilling to depreciate against the US dollar by an average of 5% Per Annum. We expect that the 10-year average depreciation rate of the Uganda shilling against the US Dollar will be lower than the current trend mainly due to the likely appreciation of the Uganda shilling when the country starts producing and exporting oil in early 2020s.

3.3 The International price of Oil

There are two major power generation plants that use Heavy Fuel Oil in Uganda and contribute up to 11 % of the total installed generation capacity. Changes in international fuel prices have significant impact on the electricity production costs of these plants and end-user tariffs in general. Over the past five years, the international price of oil has been on a declining trend from about US$100 per barrel in 2011 to US$42 per barrel in 2015 as indicated in ***Figure 4***.

Figure 4: **Trend of International Oil Prices**



Source: ***World Bank***

According to the US Federal Energy Agency, in the next five years, the international price of oil is likely to remain within the range of US$50 - 80 per barrel. This is information we have taken into consideration in the update of the LCGP.

3. FORECAST OF ELECTRICITY DEMAND

Electricity demand forecasting forms an important pillar for electricity planning since it determines the additional capacity needed and their cost implication. A high forecast leads to over-investment resulting into a redundant capacity that is expensive to the consumer and sector while a depressed demand forecast leads to capacity shortfalls as demand outstrips supply. Achievement of a balanced forecast requires application of a credible methodology, a correct planning approach, accurate information and appropriate assumptions.

3.1. Methods of Forecasting

There are a number of methods that can be used to forecast electricity demand[3] as discussed below*;*

i. Trend Method

This method assumes that demand mainly moves with time and thus the demand is predicted purely as a function of time, rather than being influenced by any other factors apart from itself. Given the limitation of the time element, it may not be conclusive to assume that the demand for electricity is only time bound.

ii. End-Use Method

The end-use method focuses on the various uses of electricity in the respective consumption sectors of the economy. This is then aggregated to come up with the total demand and the projection depends on the expected use in the near future. This method is used in developed economies with robust information that can be relied on for aggregation.

A number of off-the-shelf energy demand forecast Software like LEAP, WASP and MAED derive their demand with a similar concept of aggregating demand from the end user level. In Uganda's case, this may not easily be applied given the limited information on the kind of

[3] Demand Forecasting for Electricity by Mehra, M; Bharadwaj,A , 2000

equipment and consumption by the respective sectors in the economy and the difficulty of making futuristic end-use demand or usage patterns.

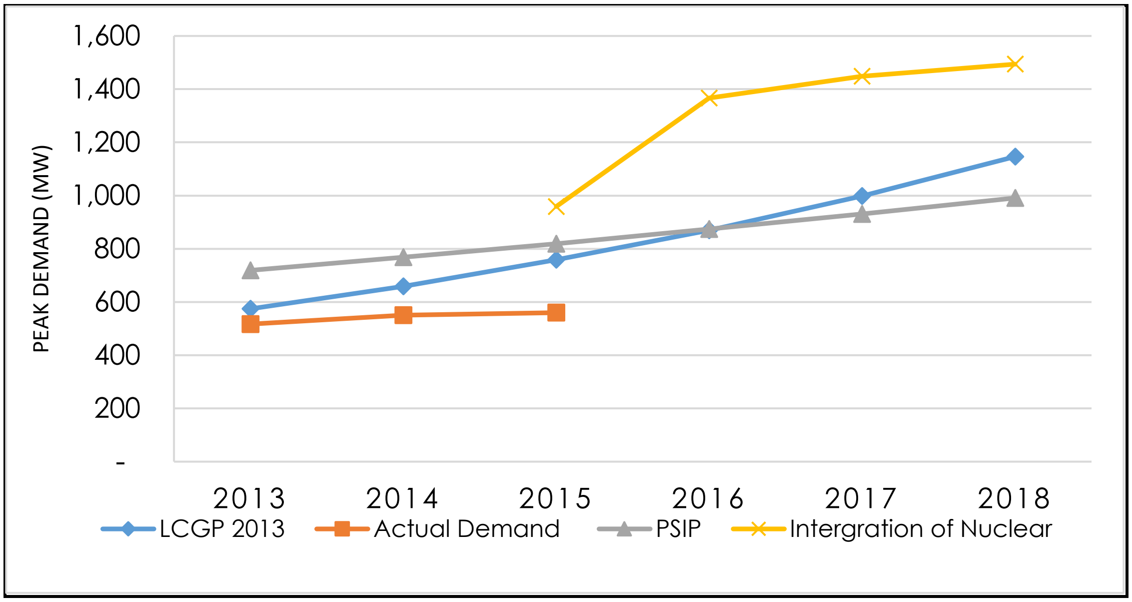
iii. Econometric Approach

This approach combines economic theory with statistical methods to produce a system of equations for forecasting energy demand. Taking time-series or cross-sectional/pooled data, causal relationships can be established between electricity demand and other economic variables. This is a popular method given its robustness and wide acceptance across scholars and practitioners for its consideration of other surrounding factors that can influence demand. This method was used in the 2010 Power Sector Investment Plan for Uganda by MEMD, the 2013 LCGP by ERA and in Kenya's 2013 Least Cost Development plan.

The 2013 LCGP followed the PSIP forecast output for the same year period 2013 to 2018 and only corrected for an observed upward bias in the forecast. This adjustment was mainly related to the over estimation of rural customer connections and suppressed demand that was attributed to poor security and quality of supply as well as strained network operating conditions. The under lying error was therefore estimated and applied to the proportional method to smoothen out the error bias on the total sales estimates by the PSIP.

In addition to the LCGP, MEMD conducted a study on the integration of Nuclear Power in Generation Capacity. This study also used the econometric method of forecasting demand for the period 2015 to 2040. The trend of the Base Case forecast is also shown in **Figure 5.** We note a significant increase in demand mainly attributed to estimation of the suppressed demand in the system.

Figure 5: Comparison of LCGP Forecast against Actual Energy demand



Source: ***ERA, PSIP and MEMD***

In September 2015, an Inter institutional Sector Planning Committee was set up by the MEMD Permanent Secretary. This Committee was chaired by the Chief Executive Officer, ERA. The role of this committee was to prepare a brief report addressing the demand and supply situation in the medium term as well as infrastructure requirements to meet demand and supply.

The forecasting methodology used in the Inter-Institutional Sector Planning report reviewed the forecast methodology of the PSIP report and then made adjustment of the PSIP forecast per customer category. The output of the forecast were then used in the inter-institutional report to derive a demand supply balance.

Given the robustness and simplicity of the previously utilized econometric forecasting model in the PSIP, the LCGP 2016-2025 retained the same methodology while building on the other modifications done on the PSIP as discussed in the following sections.

3.2. Review of PSIP Demand Forecast Methodology

The PSIP forecasting methodology used the econometric regression of electricity Sales at distribution level against income of consumers and price of electricity. Electricity demand growth equations with income and price elasticity coefficients based on natural logarithmic regression equations were generated. These were based on the four main consumer categories that include domestic, commercial, medium industry and large industry consumers.

The general structure of regression equations that were estimated in the PSIP are presented as Equation (i) below.

$$\log(E) = \log(A) + B\log(GDP) + C\log(P) \qquad \text{(i)}$$

Where: E= Electricity consumption, GDP= Gross Domestic Product, P=Price of Electricity (Tariff), B = GDP or income elasticity, C = price elasticity.

3.3. Review of Data Used in the Study

Secondary data for energy sales and electricity tariffs was captured from electricity distribution billing records from 1991 to 2007. This was captured from reports made by Umeme Limited, from 2005 to 2007, UEDCL from 2000 to 2004 and UEB from 1991 to 1999 respectively. The Gross Domestic Product (GDP) and Population data was acquired from the Uganda Bureau of Statistics.

The data used was reviewed to assess its consistence with the sources referred to and it was found to be correctly reported. In addition to the data used in the PSIP which stretched from 1991 to 2007, more recent data from 2008 to 2015 is reported and was considered in this report to establish the level of variation. A discussion of the respective variables that is Energy Sales, Electricity Price and GDP is presented in the following sections.

3.4. Review of Energy Forecast per Customer Category

3.4.1. Domestic Demand Forecast

The PSIP report considered two subcategories under the domestic consumer group, the High Consumption category and the Low Consumption Category. The high consumption energy sales were derived using the regression. In Equation (i) the PSIP authors regressed historical domestic energy sales data (1991 – 2007) for Umeme Limited on GDP per capita and the domestic electricity tariff and generated the income and price elasticity coefficients for high consumption domestic customers. Based on the derived elasticities, the authors forecasted the domestic customers' demand for the period 2008 – 2030.

While deriving the regression, the authors of the PSIP study observed that there was a negative relationship between income per capita and domestic average consumption per connection. This relationship was considered to be inappropriate and therefore the regression was recast by regressing each aggressor against energy sales separately.

The new regressions coefficients were combined from two separate regressions of energy sales and prices from 1992 to 1996 as well as energy sales against GDP per Capita with the following equations;

Specific/Average Consumption = 1.5466 + 0.885 Log GDP/Capita -------- (ii)
Specific/Average Consumption = 4.462 - 0.552 Log Price -------------------- (iii)
The resultant regression equation was;
Specific/Average Consumption=2.2766-0.552Log Price+0.886Log GDP/Capita--(IV)

Combining two coefficients from two different models is not an approach used in econometrics and therefore puts the results to doubt.

In addition, we note that only 5 years 1992-1996 of data were used instead of the entire data set which may have led to loss of information. We also compared the 7-year forecast (2008 – 2015) with actual available Umeme Sales to domestic consumers. The results in ***Table 3*** indicate that for the first 3-years, the PSIP forecast is equal to actual domestic consumer electricity demand. However, the forecast was higher than the actual domestic demand outturn by an average of 22% for the last 5 years.

Table 3: PSIP Forecast Vs Actual Domestic Demand, 2008 – 2015

Years	***Base Case PSIP Forecast (GWh)***	***Actual Demand (GWh)***	***Variance (%)***
2008	326	327	0%
2009	368	364	1%
2010	419	418	0%
2011	477	397	20%
2012	545	469	16%
2013	610	503	21%
2014	681	544	25%
2015	758	573	32%
Average			**14%**

Source: PSIP and ERA

3.4.2. Commercial Demand Forecast

In the PSIP study, commercial customer electricity demand was regressed using Umeme historical energy sales data (1991 – 2007) on commercial GDP and the commercial electricity tariffs. The resultant elasticities were then used to forecast the demand for the period 2008 – 2030. The resultant regression equation is presented as;

$$\textit{Commercial Electricity Sales} = -0.597 - 0.584 \textit{ Log Price} + 1.218 \textit{Log Commercial GDP}$$

A comparison of the PSIP forecast with the actuals (2008 – 2015) was conducted. The results shown in ***Table 4*** indicate a variance of about 8% for the last 3 years. We however note a variation between the actuals and forecasted Commercial GDP forecast. This would have contributed to the overall variation reported in the forecast.

***Table 4*: PSIP Forecast Vs Actual Commercial Demand, 2008 - 2015**

Year	Base Case PSIP (GWh)	Actual (GWh)	Variance (%)
2008	172	179	-4%
2009	188	211	-11%
2010	207	242	-14%
2011	230	215	7%
2012	256	217	18%
2013	281	259	8%
2014	308	286	8%
2015	337	312	8%
Average of Last 5 years			10%

Source: PSIP and ERA

3.4.3. Medium Industry Demand Forecast

The PSIP regression used Umeme Medium Industry energy sales data (1991 – 2007) on industrial GDP and the electricity tariffs for Medium industry. The PSIP results were reported to be inconsistent with economic theory. The results showed that an increase in electricity prices led to an increase in energy sales as shown in equation (v).

Medium Industry Sales = 1.906+0.01Log Price + 0.118Log Industry GDP—(v)

The Authors therefore dropped the regression method and instead adopted a simple trend analysis whose results were then extrapolated to forecast for the period of 2008 – 2030. These forecast results were compared with actuals (2008 – 2015) of Umeme Medium Industry consumers and found that the PSIP grossly underestimated the actual demand as shown in ***Table 5.***

Table 5: **PSIP Forecast Vs Actual Medium Industry Demand, 2008 - 2015**

	Base Case Forecast (GWh)	Actual (GWh)	Variance (%)
2008	216	223	-3%
2009	218	232	-6%
2010	220	256	-14%
2011	221	260	-15%
2012	223	342	-35%
2013	225	378	-41%
2014	227	390	-42%
2015	229	406	-77%

Source: PSIP and UETCL

3.4.4. Large Industry Demand Forecast

Large Industry customers' electricity demand was also regressed on Industrial GDP and the tariffs for this category. The elasticities were then used to forecast the demand for the period 2008 – 2030. ***Table 7*** shows the variation between the forecast and the actual demand for the period 2008 to 2015. There was an average variation of 17%.

We validated the robustness of the PSIP forecast, for the period 2008 – 2015 against actual Large Industry demand data. Over the same period, the results are presented in ***Table 6*** and indicate that PSIP forecast is on average 17% lower than the actual out turn.

Table 6: PSIP Forecast Vs Actual Large Industry Demand, 2008 – 2015

	PSIP Forecast (GWh)	Actual (GWh)	% Variance
2008	492	549	-11%
2009	539	594	-9%

2010	589	711	-17%
2011	648	859	-25%
2012	717	909	-21%
2013	790	981	-19%
2014	870	1,060	-18%
2015	958	1177	-22.9%
Average			**-18%**

Source: PSIP and UETCL

3.4.5. Demand Forecast for Rural Grids

The PSIP forecasted energy consumption of mini-grids and off-grids to grow from 3.69 GWh in 2008 to 126 GWh by 2014, as indicated in ***Table 7***. However, comparison with actual sales by mini-grids and off-grids shows that the PSIP forecast was ambitious. Review of the PSIP forecast assumptions revealed that the driver of the over estimation was the number of new connections in 2014, which was assumed to be 278,000, yet the actual connections were only 35,690.

Table 7: PSIP Forecast Vs Actual Rural Connection and Sales

	Average Sales (kWh)	**Customers**	**Total Sales (GWh)**	**Average Sales (kWh)**	**Customers**	**Total Sales (GWh)**
	PSIP Forecast			**Actual Performance**		
2008	369	10,000	3.69	646	5,754	3.72
2009	378	54,667	20.68	1028	5,909	6.07
2010	392	99,334	38.98	1256	10,890	13.68
2011	409	144,000	58.90	1206	12,734	15.36
2012	428	188,667	80.81	1208	15,560	18.80
2013	441	233,334	102.94	1161	22,056	25.60
2014	455	.278,001	126.39	777	35,693	27.75
2015	455	.278,001	126.39	777	35,693	27.75

Source: ***PSIP and ERA***

The PSIP projected that the total number of customers would increase from 10,000; 5,000; 15,000 for Base Case, Low Case and High Case respectively in 2008 to 250,000; 456,668 and 618,290 in 2012. This forecast was based on the 2002-2012 Rural Electrification Plan. However, this number of connections was not achieved. The non-achievement of customer growth targets was addressed in the RESP 2013-2022.

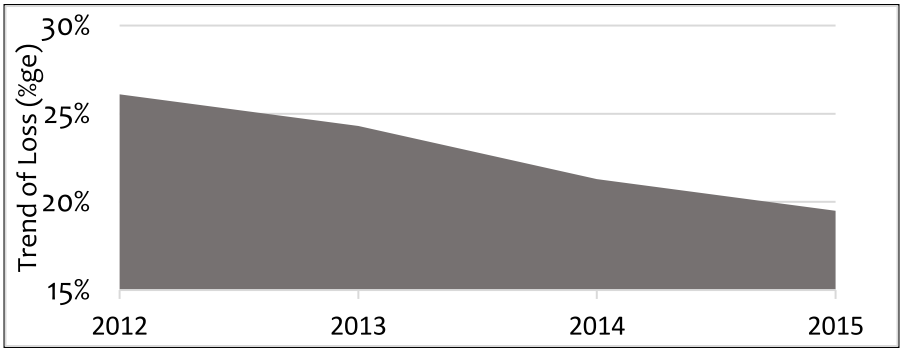
3.4.6. Projected Total Exports

The PSIP had anticipated that in the Base Case scenario, exports to Tanzania would increase from 10 MW in 2008 to 16 MW in 2012, increasing by 3% per year. On the other hand export to Kenya would remain stable at around 6 MW. Considering the actual outcome from 2008 to 2015, export to Tanzania has remained at around 12 MW while export to Kenya has generally not exceeded 3 MW, which is within the Tie line between Uganda and Kenya for Grid stability.

3.4.7. Distribution Losses

The PSIP assumed that the total electricity commercial losses would be 2%, while the technical losses would be 14.4% by 2020. However, following the review of Umeme Limited's performance targets, the loss targets were revised such that the overall distribution losses are expected to be 14.7% by 2018. In addition, the plan did not take into account the projected transmission loss trajectory. It is therefore important to take stock of the loss expectation in this LCGP. ***Figure 6*** shows the loss trajectory achieved by Umeme.

Figure 6: Trend of Distribution Losses by Umeme



Source: ***Umeme***

3.4.8. Suppressed Demand

The PSIP report considered suppressed demand to be as a result of Load shedding/ limited supply which was common during the late 2000s, poor security and quality of supply with some customers using their own generation; and strained network operation where customers switch off their equipment when voltage is below normal.

The study therefore assumed unconstrained specific consumption of 1,447 kWh compared to the 1,060kWh that was actual for domestic customers. The Authors also assumed that specific/average consumption would be 15% higher than the actual in 2007 for commercial, large Industry, and Medium industry customers. These estimates were assumed for the years 2008 to 2017 and were thus included in the demand estimates.

In 2012, following the commissioning of Bujagali Hydro Power Project PP, the country had sufficient electricity supply. During this period, it was then expected that the constrained demand would be unlocked. As was illustrated in the trend of energy sales, the growth in energy sales did not significantly change after 2012.

This limited increase in demand points to a possibility of an over estimation of suppressed demand. It is not uncommon that the power system often has some customers out of supply even if the system is fully functional with sufficient supply. It is therefore likely that the level of suppressed demand was over estimated.

3.5. Energy Sales Forecast 2016-2025

In this LCGP 2016-2025, the same forecasting methodology from the PSIP was retained given the robustness and its good theoretical foundation.

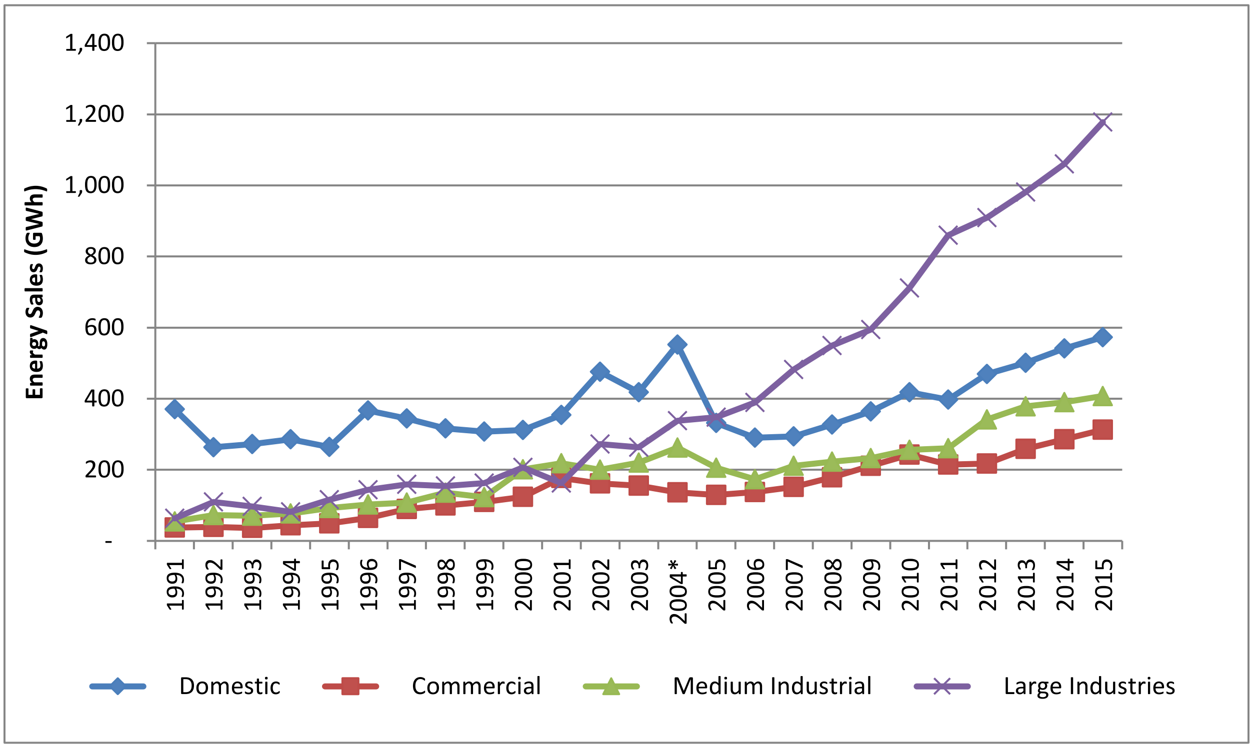
The econometric regression method was used for Large Industry, Medium Industry and Commercial. However, given the challenges of the observed reverse relationship for the domestic customer sales with Income per capita reported in the PSIP report, the forecast for this category was based on a bottom-up estimation method depending on the projected connections and average consumption starting right from the household.

3.5.1. Data Source and Trend

a) Energy Sales

All the data that was used is shown in ***annex 1*** of this report for reference purposes. As shown in ***figure 7***, the trend of energy sales to all customer categories has increased from 1991 to 2015. In particular, as was reported in the PSIP, energy consumption by the large industry customers is observed to be increasing at a higher rate compared to the rest of the customers.

Figure 7: Trend of Energy Sales per customer Category



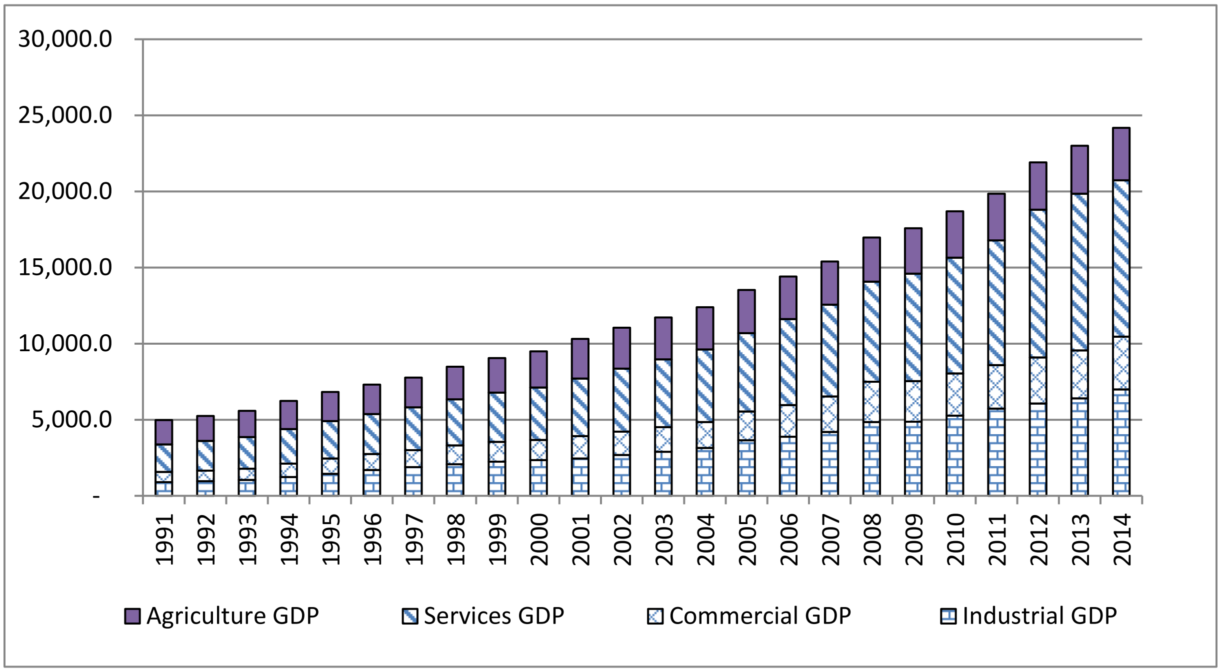
Source: ***Umeme, UEB, UEDCL***

b) Gross Domestic Product (GDP)

The Industrial GDP was composed of the Mining and Quarrying, Manufacturing, Electricity and Water as well as Construction Sectors. We note that the construction sector does not necessarily contribute to the Industry that consumes electricity apart from the construction material that are already captured under manufacturing. The Commercial GDP on the other hand was composed of whole sale and retail trade sector as reported by the Uganda Bureau of Statistics.

Figure 8 shows the trend of GDP by sector at constant price. It shows that the growth has been most significant in the services industry followed by the Industrial sector. Almost no movement is observed in the agricultural sector.

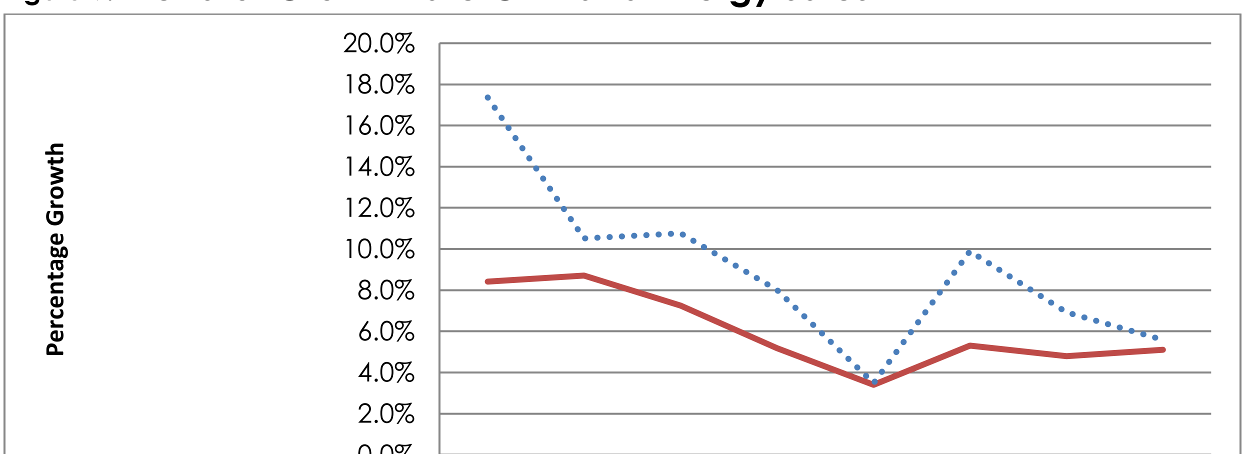
Figure8: Trend of GDP by Sector



Source: UBOS

In addition to the above, a visual illustration of the relationship between GDP and energy sales is shown in ***Figure 9***. It can generally be observed that there is a positive relationship between the movement in GDP and energy growth rates.

Figure 9: Trend of Growth rate GDP and Energy sales



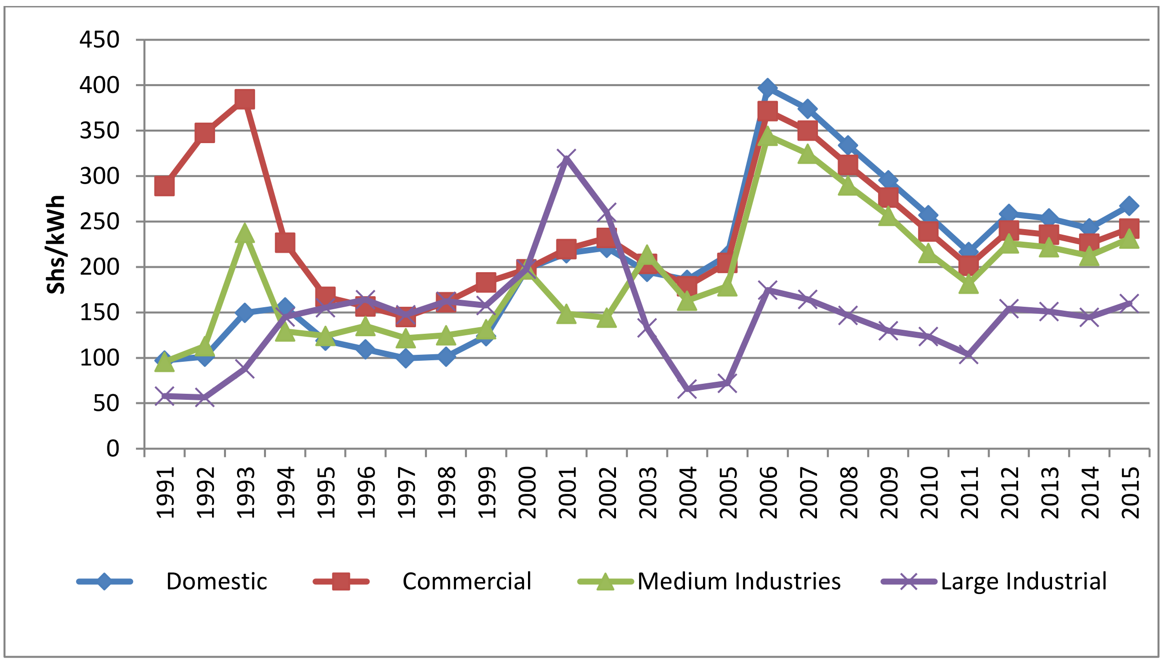
	2007	2008	2009	2010	2011	2012	2013	2014
GDP Growth rate	8.4%	8.7%	7.2%	5.2%	3.4%	5.3%	4.8%	5.1%
Growth in GWh Sales %	17.4%	10.5%	10.8%	8.0%	3.5%	9.9%	6.9%	5.6%

Source: UBOS and ERA

c) Trend of Electricity Prices/Tariff

Following the implementation of the automatic tariff adjustment mechanism in 2014, there has been an observable movement in electricity prices per Quarter. This was designed in order to adjust for inflation, exchange rate and oil prices as provided in the methodology[4]. The trend of Uganda's nominal electricity prices was generally stable with minimal adjustments over the past 20 years. In real terms however, an increase in the electricity price was observed in the early 1990s and the mid-2000. ***Figure 10*** shows the trend of electricity prices by customer category in real terms.

Figure 10: Trend of Tariff in Real Terms per Customer Category



Source: ***ERA approved tariff and UEB Data Base***

3.5.2. Diagnostic Test for Variables

Best practice in econometrics requires that time series data used for forecasting is stationery and that a long run relationship exists among the

[4] http://era.or.ug/index.php/2013-12-14-14-58-04/guidelines

variables. It is observed that the PSIP methodology did not reflect this important step.

In this case, a cointegration method was used to test the existence of a long run relationship. As stated by ***Engle and Granger***, ***"If a set of variables are cointegrated, then there exists a valid error correction representation of the data, and vice versa[5]".*** As such, a cointegration test was conducted using the following steps.

i) Test for Stationarity

Annex 2 shows the results from the Augmented Dickey Fuller test for stationarity. The table shows that before differencing, all the variables became non stationary given that the absolute values of the test statistics are less than the critical values. However, it is illustrated that after the first difference, all the variables are stationary. We can therefore conclude that the electricity sales, electricity prices and GDP are integrated of order one thus I (1) and thus have a long run relationship.

ii) Test for existence of cointegration

To test for the existence of cointegration the **"Engle and Granger 1987"** method was used. Regression of energy sales against GDP and tariff were conducted for the respective consumer categories and an ADF test for stationarity of the residuals was conducted.

The First cointegration test with Electricity Sales, tariff and GDP showed no existence of cointegration in all customer categories as shown in **Annex 2**. However, regressions without tariffs showed that cointegration actually exists between GDP and electricity sales in all the respective customer categories under review.

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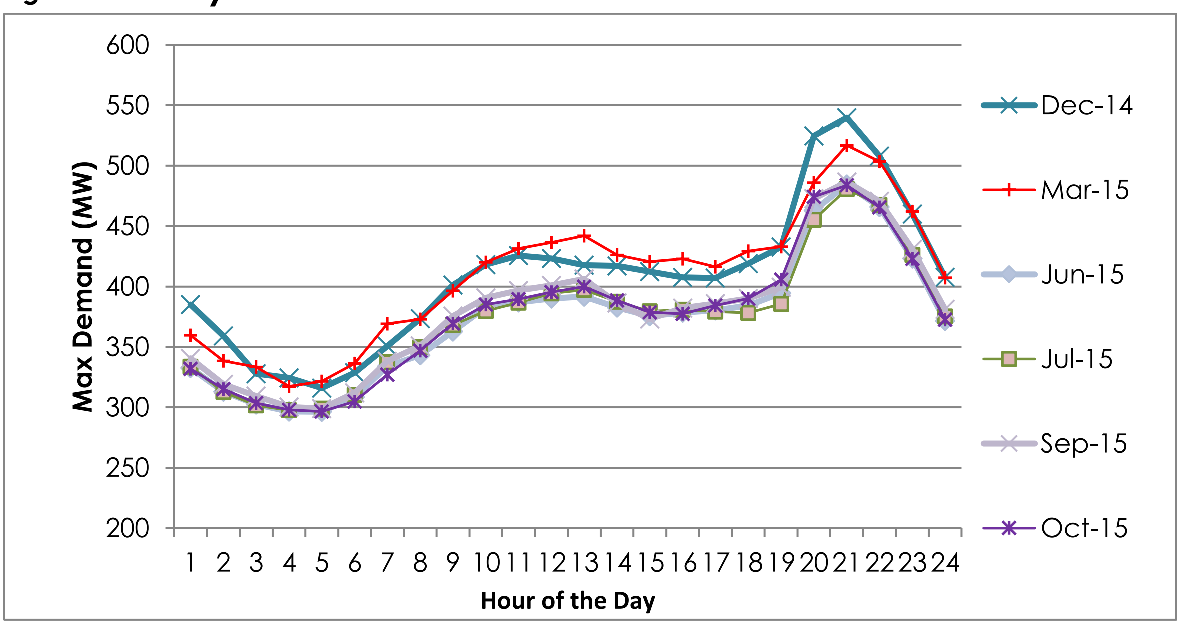
[5] Engle and Granger, 1987, Cointegration and Error Correction: Representation, Estimation and Testing, Econometrica, 55 251-276.

This therefore confirms the existence of a long run relationship between electricity sales and income. The problem with electricity tariff is likely to be due to the fact that tariffs were not changing in nominal terms for a long time which could have had marginal effects on the consumer. None the less, given that the Authority implemented the quarterly tariff adjustment mechanism, we expect that going forward, tariffs will impact on the energy sales. From the foregoing, we therefore maintained both tariff and GDP as the variable that influence sales.

3.5.3. Daily Load Curves

In order to establish the system load curve, a review of the hourly capacity demand was conducted. ***Figure 11*** shows that no significant shift in the Load profile is observed from the respective load curves as shown from 2014 to 2015. Uganda's daily load curve indicates that there is no variation in the load pattern throughout the months of the year. In our analysis of demand, we therefore assumed the same load curve all year round.

Figure 11: **Daily load Curves 2014-2015**



Source: ***UETCL***

3.6. Regression for Elasticities

In order to forecast the sales, a regression of the log of the variables was conducted for the respective customer categories as shown in the ***Annex 1*** and summarized in the equations below. The results for the respective energy sales all show that the models were correctly specified with a significant F statistic. The sign on the independent variables is positive for GDP which implies that energy sales are positively influenced by income.

In addition, the negative sign on electricity tariff implies that an increase in price leads to a drop in energy sales in all the respective customer categories. This behavior is in line with the economic behavior of a normal good which was originally assumed for electricity. We therefore used the regression equations to forecast the energy sales for the respective customer categories using the assumptions for the forecast of GDP from 2016 to 2025.

a. ***Commercial Electricity Sales=-4.77 -0.29 Log Price+1.21Log Commercial GDP***
b. ***Med-Industry Electricity Sales=-3.22—3.22log Price+0.89Log Industry GDP***
c. ***Large-Industry Electricity Sales=-5.89-0.24 Log Price+1.37Log Industry GDP***

3.6.1. Forecasting Domestic sales

As REA continues to implement the RESP 2013-2022, the rate of household connections to the national grid is expected to grow significantly following the National Rural Electrification target of over 1.2 Million rural customer connection by 2022. We have reviewed Umeme's total sales to the Domestic consumers and the average consumption per house as shown in ***Table 8***.

The table shows that while the total domestic customers have steadily increased, the average consumption per household has gradually reduced. This is due to the increase in rural customers whose consumption is lower than the existing urban and peri-urban customers. This trend is expected to continue in the future as more rural connections are made.

Table 8: **Umeme Domestic customer Connection Rate**

Year (s)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Domestic sales (GWh)	290	293	327	364	418	397	469	503	544	591
Customers '000	287	277	278	286	325	419	474	530	604	753
kWh per Household	1,011	1,059	1,177	1,272	1,287	949	991	948	901	865

Source: ***Derived From Umeme Annual Reports***

3.7. Forecasting Scenarios

In order to capture the sensitivity of the forecast and prepare for different outcomes, we considered a number of scenarios as discussed in the following section. This LCGP maintained three main scenarios, the Base case, High case and Low case.

a. Base Case Forecast Scenario

This case assumed the business as usual scenario in the economy and thus adopted the average GDP growth rate as projected by the second National Development Plan (NDP II) [6]2015-2020.The National Planning Authority while developing the NDPII 2015/16 to 2019/20 estimated that the GDP growth rate will be as indicated in ***Table 9***.

[6] *npa.ug/wp-content/uploads/NDPII-Final.pdf*

Table 9: Forecast of GDP Growth Rate

2015/16	2016/17	2017/18	2018/19	2019/20
5.8%	5.9%	6.4%	6.7%	6.8%

Source: ***NDP II***

For the Base Case forecasting scenario, the same growth rate was adopted for the period 2015 to 2019. While the 2019/20 growth rate was maintained from 2020 to 2025.

However, we note that the growth rates were reported in Financial Year terms while energy sales were reported in Calendar Years. In order to convert the rates from Financial Year to Calendar Year, a two year moving average was used for each year. ***Table 10*** shows the GDP growth rate that was used for the period 2015 to 2025.

Table 10: **Estimated Annual GDP Growth Rate**

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GDP Growth	5.6%	5.9%	6.2%	6.6%	6.8%	6.8%	6.8%	6.8%	6.8%	6.8%

Source: ***Team's Computations***

Using the forecast of the GDP growth rate, the forecasted real GDP from 2015 to 2025 is shown in ***table 11.***

***Table 11*: Base Case Projected GDP by Sector**

GDP(Shs ,Bn)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Industry	7,388	7,820	8,301	8,844	9,441	10,083	10,769	11,501	12,283	13,119
Services	15,524	16,432	17,442	18,585	19,839	21,188	22,629	24,168	25,811	27,566

Source: ***Team's computations***

In order to project the domestic demand up to 2025, we assumed total new connection of 140,000 from 2016 up to 2025 as submitted by Umeme. In addition, we assumed that the consumption per household would annually reduce by 8%. Using the above assumption, the projected Domestic energy sales are as shown in ***Table 12***.

Table 12: **Projected Domestic Energy Sales**

	No. of Domestic Customers	**Average Consumption per Household (kWh)**	**Domestic Energy Sales (GWh)**
2016	843,903	782	660
2017	983,903	719	708
2018	1,123,903	662	744
2019	1,263,903	609	770
2020	1,403,903	560	786
2021	1,543,903	532	822
2022	1,683,903	506	851
2023	1,823,903	480	876
2024	1,963,903	456	896
2025	2,103,903	433	912

Source: ***Umeme***

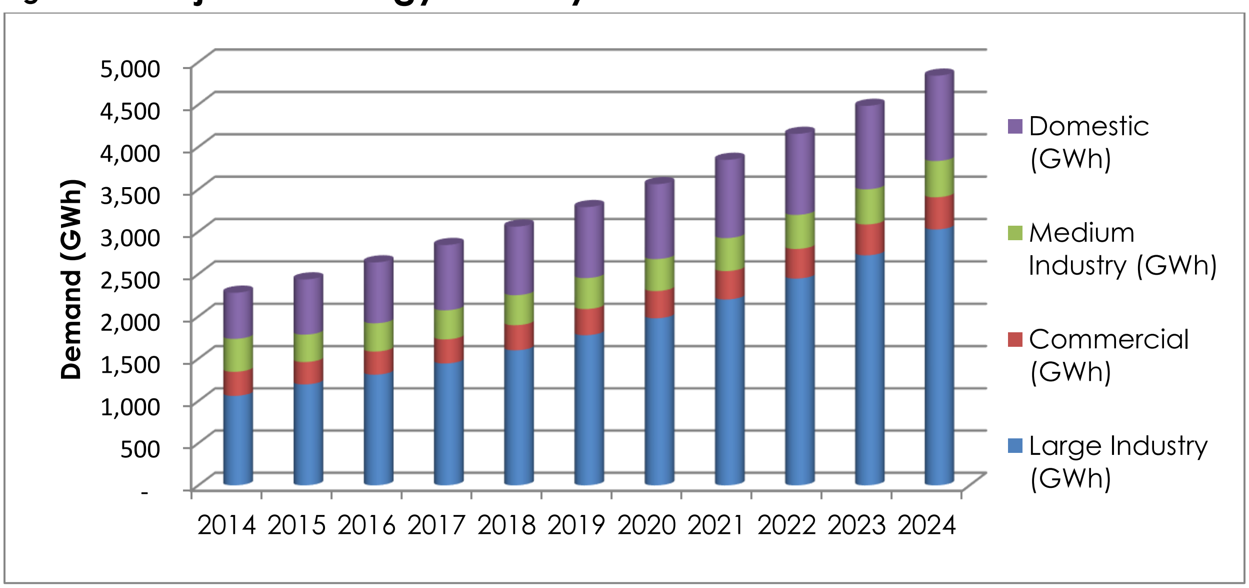
Using the above methodology for forecasting the energy sales at distribution level, the resultant total energy forecast for the base case are shown in ***Table 13*** and ***Figure 12***. The energy sales would grow from 2,598 GWh in 2016 to 4,929 GWh in 2025. An average growth rate of 7% is observed from 2016 to 2025. The largest energy sales are projected to come from Industrial consumers.

Table 13: **Base Case Projected Energy Sales by Umeme**

	Large Industry (GWh)	Commercial (GWh)	Medium Industry (GWh)	Domestic (GWh)	Total Umeme Sales (GWh)
2016	1107.4	325.4	413.4	752.2	2598.5
2017	1201.8	349.8	436.1	801.6	2789.3
2018	1310.9	377.8	461.5	838.3	2988.5
2019	1433.6	408.9	489.3	864.0	3195.8
2020	1568.9	442.8	518.9	918.5	3449.1
2021	1716.8	479.5	550.3	967.3	3713.9
2022	1878.7	519.2	583.7	1010.7	3992.3
2023	2055.9	562.3	619.0	1049.1	4286.3
2024	2249.8	608.9	656.5	1082.7	4598.1
2025	2462.0	659.4	696.3	1112.1	4929.8

Source: ***Computations***

Figure 12: **Projected Energy sales by Umeme**



Source: ***Internal Computations***

b. High Case Forecast Scenario

The High Case Scenario assumed an increase in economic activity, moving forward including accelerated connection through the new 2013-2022 Rural Electrification Strategy, accelerated industrialization among other activities being undertaken to accelerate economic activity in the country. A GDP growth rate of 10% per year was adopted for this case to forecast the large industry, Medium Industry and Commercial customers.

To estimate the Domestic customer sales in the High Case, we assumed that Umeme will connect 180,000 customers per year. In addition, we assumed that the consumption per house hold connection would reduce by only four (4%) per year.

As a result of the assumption for the High Case scenario, the resultant demand by Umeme is shown in ***Table 14***. The average growth rate in demand is 11%, with demand expected to grow from 2,843GWh in 2016 to 7,076GWh in 2025. The main driver of demand still remains industrial demand with more than half of the growth in the total demand.

Table 14: **High Case Projected Energy Sales by Umeme**

	Large Industry (GWh)	**Commercial (GWh)**	**Medium Industry (GWh)**	**Domestic (GWh)**	**Total Umeme Sales (GWh)**
2016	1235	358	429	820	2843
2017	1408	402	452	896	3158
2018	1604	452	479	954	3488
2019	1828	507	508	997	3839
2020	2083	569	538	1071	4261
2021	2373	638	571	1138	4721
2022	2704	716	606	1198	5224
2023	3081	804	642	1252	5779
2024	3511	902	681	1299	6394
2025	4001	1013	722	1340	7076

Source: ERA

c. Low Case Forecast Scenario

The *Low case scenario* assumed that the demand would drop under lower expectations of the level of economic activity at about 3.4% GDP growth rate on average from 2016 to 2025. The consideration of the 3.4% GDP growth rate was because it is the lowest growth rate registered for the past 10 years which happened in 2011. The consumption per house hold connection would reduce by 10% per year, while the average new connections would be 70,000. This would translate into total sales as shown in ***Table 15*** at an average growth rate of 4%.

***Table 15*: Low Case Projected Energy Sales by Umeme**

	Large Industry (GWh)	Commercial (GWh)	Medium Industry (GWh)	Domestic (GWh)	Total Umeme Sales (GWh)
2016	1043	309	406	633	2390
2017	1092	321	428	637	2478
2018	1143	335	453	637	2567
2019	1196	348	480	632	2657
2020	1252	363	509	651	2776
2021	1311	378	540	668	2897
2022	1372	393	573	682	3021
2023	1437	410	608	694	3149
2024	1504	427	645	705	3280
2025	1575	444	684	713	3415

Source: ERA

3.7.1. Sales to Other Distribution Companies

Umeme represent more than 97% of energy purchases for Uganda's ESI. However a number of other small distribution companies were set up with the support of REA. Among the other distribution companies are, Pader Abim Community Multipupose Electric Cooperative Society Limited (PACMECS), Bundibugyo Energy Co-Operative Society (BECS), Kilembe Investment Limited (KIL). ***Table 16*** provides some highlights of the performance of these companies. Since most of the REA activities are supporting rural electrification, we have assumed a 20% growth in energy purchases to all the mini- distribution companies from 2016 to 2025.

Table 16: Connection and Sales of Mini-Grid as at end of 2015

	Number of Customers				Total Purchases (GWh)
	FERDSULT	PACMECS	BECS	KIL	
2012	7,500	1,181	1,596	1,981	31.96
2013	11,023	1,323	2,085	3,312	33.71
2014	17,738	1,842	3,381	6,450	39.08
2015	22,464	2149	4165	7659	43.32

Source: ERA

3.8. Demand at Generation Level

In order to convert energy sales at distribution to generation requirement, we added back all exports by UETCL and energy losses. The following sections derive the demand at generation level.

3.8.1. Forecast for Export

Uganda has on average exported 12 MW to Tanzania and about 2 MW to Rwanda. The general exchange of power between Uganda and Kenya has been on the basis of the tie line agreement of only four 4 MW. ***Table 17*** shows the trend of export by Uganda to its neighboring countries. We note that exports have not significantly changed from 2009 to 2015.

Table 17: Energy Exports

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Export (MWh)	65	66	82	76	88	99	105	167	121

Source*: *UETCL Annual Report

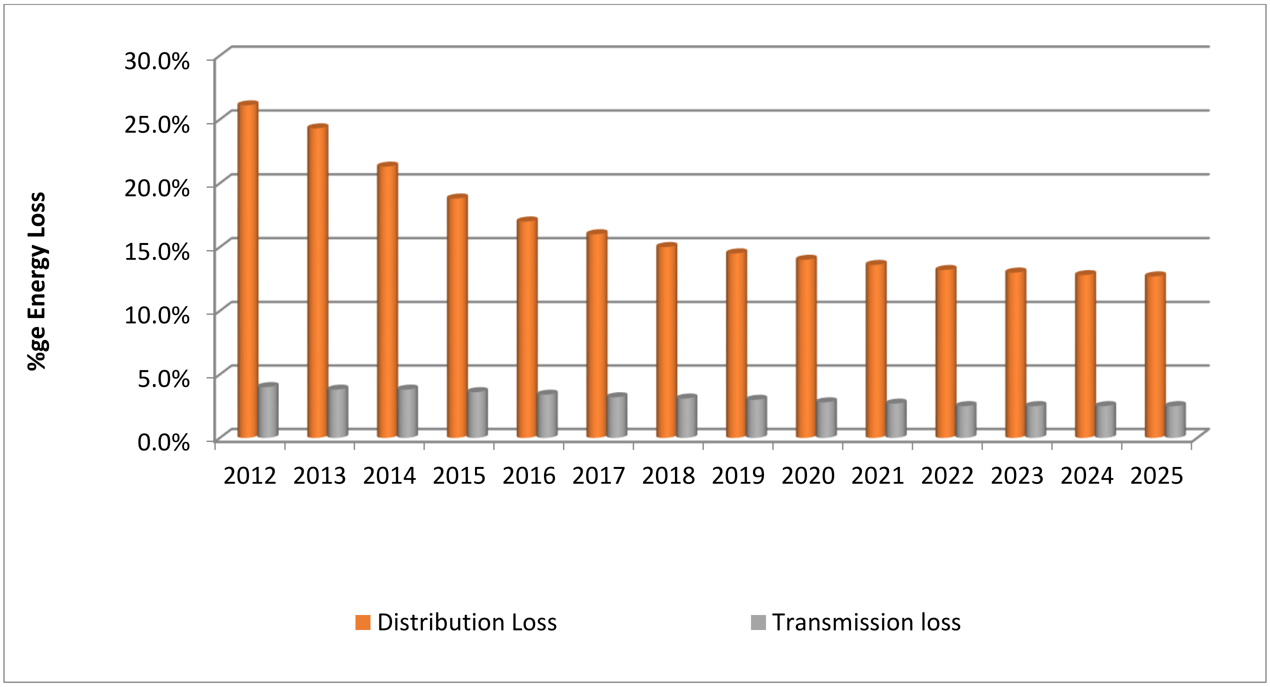
Uganda has not concluded any new export contract. However a Wheeling Agreement was signed for Kenya to export power to Rwanda over UETCL's network until 2019. Though this power will be wheeled over Uganda's network, the net effect of this transaction is expected to be negligible in terms of additional energy demand.

For this report, we assumed that any significant export would be made at the earliest in 2018. This assumption is mainly based on fact that Uganda does not have any new contract in the pipeline to export power. We assumed that the same exports will be as those in 2015 until 2017. Export will then increase by 20% in 2018 and another 20% increase in 2020.

3.8.2. Trend of Distribution and Transmission Losses

During the Review of Umeme's License in 2012, ERA set the loss reduction target trajectory that will have distribution losses at 14.7% by 2018. In UETCL's Multiyear Tariff Review 2014 - 2016, the transmission loss trajectory was also set from 3.8 % in 2014 to 3.3 % in 2016. For this forecast, we have assumed distribution loses to be 11 %, while transmission loses will be at 2.3 % by 2025 as shown in ***Figure 13***.

Figure 13: **Distribution and Transmission Loss Trajectory**



Source: **ERA**

As a result of the above assumptions, the resultant generation demand is as shown in ***Table 18*** and illustrated in ***Figure 13***. The total capacity requirement is expected to increase to 1,057MW; 1,849 MW and 753 MW by 2025, with an average growth rate of 7.3%; 12.2% and 4.1% for Base Case, High Case and Low Case respectively.

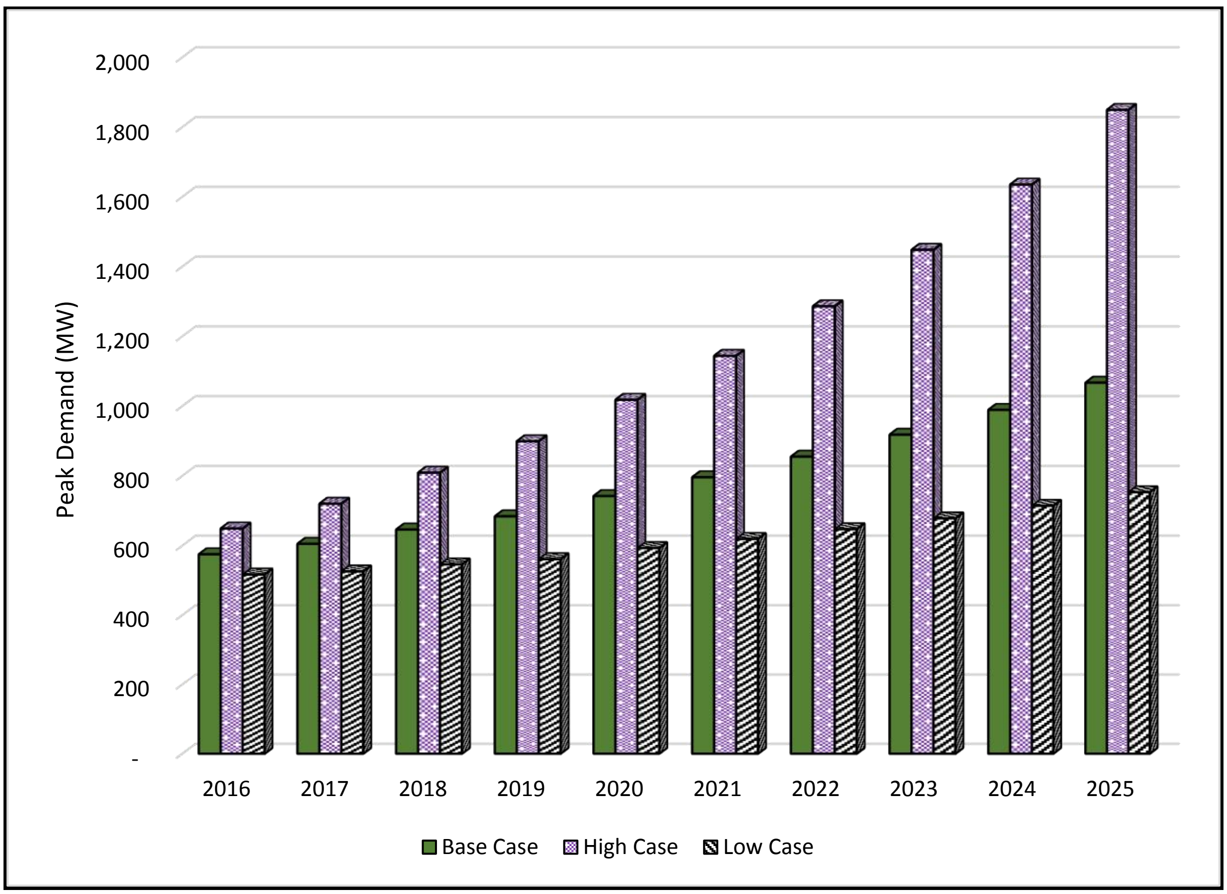
Table 18: **Projected Demand at Generation Level**

Year	**Total Generation (GWh)**	**Peak Demand (MW)**	**Total Generation (GWh)**	**Peak Demand (MW)**	**Total Generation (GWh)**	**Peak Demand (MW)**
	Base Case		**High Case**		**Low case**	
2016	3,546	575	4,001	649	3,281	517
2017	3,720	605	4,431	720	3,333	526

2018	3,974	646	4,971	809	3,456	546
2019	4,203	684	5,520	899	3,549	561
2020	4,548	742	6,239	1018	3,738	593
2021	4,875	796	7,001	1144	3,899	619
2022	5,223	855	7,859	1286	4,071	647
2023	5,610	918	8,846	1448	4,266	678
2024	6,043	989	9,990	1635	4,489	714
2025	6,517	1067	11,299	1849	4,736	753

Source: ***ERA***

Figure 14: **Projected Energy Sales 2016-2025**



Source: ***ERA***

4. PROJECTED ELECTRICITY SUPPLY 2016 – 2025

4.1. Introduction

Since the development of the last LCGP in 2013, some projects either commissioned, upgraded their generation or started construction. Kasese Cobalt Company Limited (KCCL), increased their dispatch to the national grid from around 1 MW to an average of 5 MW. This followed the company's indication that it had exhausted the cobalt which was consuming most of the power and therefore all the energy would be exported to the national grid.

In the same year 2013, the 9 MW Hydromax HPP Kabalega was commissioned and started supplying electricity to the national grid. This plant however faced some power evacuation challenges so it has not been in position to dispatch at full capacity. In addition, Kakira Sugar Ltd ramped up its capacity from 22 MW to 52 MW. However, out of the 52 MW, only 32 MW are committed to the national grid meaning that only 20 MW of additional 30 MW capacity was developed for the Grid. In 2013 still, Electro-maxx thermal plant expanded its capacity from 18 MW to 50 MW. The plant is still run on a merit order dispatch largely as a peaking plant. Details of these plants are discussed later in this report.

In the review of the various sources of energy that would satisfy the projected demand, different technologies were considered to supply the projected demand from 2016 to 2025 as discussed below.

4.1.1. Review of Uganda's Potential source of Electricity

4.1.2. Large Hydro

There are three existing large Hydro Projects; Kiira (180 MW) and Nalubale (200 MW), managed by Eskom Uganda Limited and Bujagali

HPP (250 MW), located on the Nile River. All the future large hydro projects are also located on the Nile River. The committed projects include; Karuma (600 MW), Isimba (183MW), Ayago (840 MW) and Agago-Achwa (83 MW). In addition, the other candidate plants include; Oriang 392 MW and Kiba 600 MW.

4.1.3. Small Hydro

The small hydro projects in Uganda are generally developed on the basis of the run of the river technology stationed on the small rivers in the country. The GETFiT Program has given a boost to the development of small renewable energy projects with small hydro project developers taking the majority. As it was indicated earlier, more than 8 GETFiT Program approved projects are expected to be commissioned within the next two (2) years. In addition, more private developers have expressed interest and are apparently conducting feasibility studies for their projects as will be discussed in detail later.

4.1.4. Biomass/Bagasse Cogeneration

Cogeneration is the simultaneous generation of electrical power and thermal energy through a single fuel. More than 3 sugar factories are developing generation plants using sugar cane wait (Bagasse), as fuel. These include Kakira (32 MW), Mayuge (9 MW) and Kaliro (11.9 MW). As technology advances and more sugar factories are set up, the prospects of this technology is quite high in the medium and long term. Prospects into the development of generation projects using other biomass resources are still under consideration.

4.1.5. Wind

Uganda has an indication of Wind energy prospects in the North Eastern Part of the Country. MEMD is apparently conducting feasibility studies while some two developers have been licensed to develop this technology in the same region. Wind energy in Uganda is considered in line with other intermittent renewable energy resources. For this report, we considered Wind as one of the sources of supply over the planning horizon.

4.1.6. Geothermal

The MEMD is still undertaking feasibility studies on geothermal generation. In 2014, the MEMD conducted surface and subsurface exploration studies on geothermal sites in order to establish conceptual models for drilling and development of geothermal resources for electricity generation[7]. Although the prospects of harnessing energy from this resource cannot be down played we assumed that no generation will be attained from geothermal until 2025. This is due to the risks, high drilling costs as well as the long lead time required to complete the studies and develop.

4.1.7. Natural gas Plants

Using natural gas, one method of generating electricity is to burn the gas in a boiler to produce steam, which is then used by a steam turbine to generate electricity. A more common approach is to burn the gas in a combustion turbine to generate electricity.

Another technology that is growing in popularity is to burn the natural gas in a combustion turbine and use the hot combustion turbine exhaust to make steam to drive a steam turbine. This technology is called "combined cycle" and achieves a higher efficiency by using the same fuel source twice.

[7] Read: The Joint Sector Review Report 2013/14 by the Ministry of Energy

MEMD has indicated that there will be some natural gas that will be harvested in the Albertine region in the process of drilling the oil. We therefore considered natural gas as one of the resources in the plan.

4.1.8. Thermals

The national grid currently has two 50 MW plants that use imported Heavy Fuel Oil, that is Electro max Tororo and Jacobsen Namanve, which are operating under a merit order dispatch regime. GoU has indicated that some fuel from the Albertine region will be committed to generation of electricity. The quantum of fuel to be provided and time it will be available for use is not yet confirmed. However, the indicative capacity to begin with is around 50 MW which can later on be expanded accordingly.

4.1.9. Nuclear Energy

Nuclear energy has been considered as one of the main energy resources that will satisfy Uganda's energy demand for the future. By 2014, the nuclear roadmap development strategy 2014-2016 was developed. This was followed by the commissioning of a study to integrate nuclear power in the generation capacity plan for a period 2015-2040. A deliberate and systematic process has been noted in an effort to integrate this technology in the future. The preliminary indication is that Nuclear energy will at the earliest be available in 2028. We have therefore not included this nuclear energy as a resource in the next 10 years.

4.1.10. Solar Photovoltaic (PV)

Photovoltaic (PV) is the generation of electricity from sunlight through an electronic process that occurs in semiconductors. In these conductors, electrons are induced to travel through an electrical circuit which will ultimately generate power. The Government of Uganda and the GETFiT

Program introduced a Solar-PV under the GETFiT Premium Payment Mechanism (GFPPM). A reverse tendering processes was conducted in 2014, with phase 1 targeting a total of 20 MWp Grid connected solar PV (4x5MWp plants). At the end of the tendering process, 2 developers were awarded licenses to develop two (2) projects of 10MWp Projects each. We have therefore considered this technology as one of the options. In addition, ERA had already awarded some unsolicited bids.

4.2. Current Sources of Electricity

4.2.1. Eskom Uganda Ltd (380 MW)

The Directorate of water Resource Management (DWRM), reported that as a result of good hydrology, water levels between River Nile and Lake Victoria had finally risen above 12.5 meter mark. We note that with such water levels, it is possible to increase the discharge above 800 CUmecs if need arises. UETCL already got an approval for water release up to 950Cumecs, which will end in May 2016. However, the limit of water release of up to 800 Cumecs was adopted as a conservative position for the long term projection. At 800 Cumecs, the average capacity was 139 MW for the past 5 years, we assumed the same capacity going forward in the plan.

4.2.2. Bujagali Energy Limited (250 MW)

The water release at the Nalubaale / Kiira complex directly influences the generation of Bujagali Energy Limited. It has been established that Bujagali's capacity is 1.21 times more than the generation of Eskom. We assumed an average capacity of 168 MW for Bujagali in this plan.

4.2.3. Africa EMS Mpanga Ltd (18 MW)

This plant was commissioned in 2011, as a run of the river. It has not experienced any major technical challenge since its commissioning. The average generation capacity for the plant in the past five years is 9.5 MW. We have thus assumed the same in this plan.

4.2.4. Tronder Power Ltd – Bugoye (13MW)

This plant was commissioned in 2009, with an installed capacity of 13 MW. No major generation problems have been reported in operation. The plant generated at an average capacity of 8.6 MW in the past six years. This translates into average energy generation of 75.336GWh. We have assumed the same generation capacity for the plant in the future.

4.2.5. **Kasese Cobalt Company Ltd -KCCL (10.5MW)**

In 2013, KCCL indicated that it had exhausted cobalt from it mines which were consuming part of the energy that was being generated. As a result, the company increased its energy supply to the National Grid in the second half of 2014. The plant generated on average 64.58 GWh in 2014 and 2015 compared to 17.55 GWh earlier when the cobalt plant was still active. We have therefore assumed an average generation capacity of 7.2 MW to the National Grid.

4.2.6. Tibet Hima Ltd – THL (5MW)

The floods in the Kasese region continue to pose a threat to the normal operations of this plant. None the less, we project that THL will generate an average of 2.5 MW.

4.2.7. Eco Power-Ishasha (6.5 MW)

This 6.5 MW Plant was commissioned in 2011. The plant is estimated to generate 28.99 GWh per year. This energy translates into an average generation capacity of 3.3 MW per year. We have assumed the same capacity for the forecasted period.

4.2.8. **Kakira Sugar Works (32 MW)**

In 2013, KSL increased its capacity from 12 MW to an additional 20 MW leading to a total capacity of 32 MW exported to the national grid. The plant is estimated to generate at an average capacity of 25 MW, translating into energy of 219 GWh. In addition, KSL was approved by GEFiT Program and it is expected to get additional US cents 1/kWh top-up premium.

4.2.9. Kinyara Sugar Works Ltd

The plant has on average generated 1.5 MW to the national Grid. However, the company plans to ramp up its generation to 30 MW committing 20 MW to the grid in 2017. We have thus assumed generation of 1.5 MW for 2016 and 16 MW from 2017 onwards.

4.2.10. Hydromax Ltd - Buseruka (9MW)

Hydromax plant experienced evacuation challenges which have not allowed it to fully evacuate its power since its commissioning. In July 2014, refurbishment works on the Hoima - Busunju line was completed by Umeme to facilitate the evacuation of the plant. This refurbishment improved on the evacuation capacity from 3 MW to about 6 MW. However, more works are expected to facilitate stable evacuation of the plant. This among other efforts is expected to reduce the evacuation problem until the completion of the Nkenda substation as a permanent solution in 2017.

Given the improvement in evacuation, the plant is expected to generate an average of 4 MW. After the completion of Nkenda substation, it will on average generate 6 MW.

4.2.11. Electro-Maxx Ltd - Tororo (50 MW)

The plant expanded its capacity in 2013 from 18 MW to 50 MW. Since the commissioning of Bujagali, the plant has been operating minimally as an emergency and peaking plant. In order to ensure that the plant is available on call, a minimum dispatch of 7 MW is maintained. We have assumed the same dispatch and any addition dispatch to be called on merit order going forward when all cheaper options have been exhausted. Electro-Maxx's license expires in 2017. We have assumed that the plant will not be in mix after 2018.

4.2.12. Jacobsen Uganda Power Plant Ltd - Namanve (50MW)

The company's operational license expired in August 2014. In order to allow for takeover by UEGCL, Jacobsen Ugnada Power Plant Ltd was given a one year license extension. There are further reviews by MEMD on the management of this plant moving forward. The plant is however expected to be available all through the planning period, dispatching the minimum 7 MW and any additional capacity on merit order. ***Table 19*** shows the available generation projects as at April 2016.

Table 19: Existing Generation Plant in Uganda 2016

Technology	Name of Plant	Installed Capacity	Average Available Capacity
Hydro	Eskom	380	140
	Bujagali	250	168
	Africa EMS Mpanga	18	9.5
	Hydromax Buseruka	9	4
	Eco Power Ishasha	6.5	3.3

Technology	Name of Plant	Installed Capacity	Average Available Capacity
	Kilembe Mines Limited	5	2.5
	Kasese Cobalt Company Ltd	10.5	7.2
	Tronder Power Bugoye	13	8.6
Bagasse Cogeneration	Kakira Sugar Limited	32	25
	Mayuge Sugar	3	2.4
	Sugar & Allied Kaliro	6.9	5.5
	Kinyara Sugar Works	7.5	1.5
Thermal	Jacobsen-Namanve	50	45
	Electro-Maxx-Tororo	50	45

Source: ERA

4.3. Committed and Candidate Projects

Table 20 shows a list committed and candidate plants that were considered as possible sources of generation. These plants include those that were licensed and are under construction, those already constructed but awaiting evacuation as well as those under feasibility study from various technologies. Details of each plant is indicated in ***Annex 4.***

Twenty five (25) Hydropower Projects are currently under feasibility study, of which, 22 projects can be classified as small Hydropower Projects. The small hydropower projects post a combined installed capacity of 547.871 MW.

Table 20: **Committed and Candidate projects**

No.	**Project Name**	**Installed Capacity (MW)**	**Estimated Commission Date**
1	Siti 1 HPP	5	2017
2	Access Solar	10	2016**(Commissioned)**
3	Isimba HPP	183	2018
4	Rwimi HPP	5.5	2017
5	Lubilia HPP	5	2018
6	Muvumba HPP	6.5	2017
7	Waki Hydro HPP	4.8	2018
8	Nkusi HPP	9.6	2017
9	Nyamwamba HPP	9	2017
10	Tororo North Solar	10	2017
11	Ms Xsabo Solar	20	2018
12	Mahoma HPP	3.2	2018
13	SCOUL	26	2018
14	Sindila HPP	4.8	2018
15	Nengo Bridge HPP	6.7	2019
17	Agago-Achwa HPP	83	2018
18	Kyambura HPP	7.6	2018
19	Nyamagasani 2 HPP	5	2018
20	Nyamagasani 1HPP	15	2018
21	Bukinda HPP	6.5	2018
22	Ndugutu HPP	4.8	2018
23	Siti 2 HPP	17	2018
25	Kinyara	25	2018
26	Albatros Thermal Power	50	2021
27	Kakaka HPP	5	2020
28	Nyagak III HPP	4	2019
29	Sironko HPP	12	2019
30	Lake Albert Natural Gas Project	50	2021

No.	Project Name	Installed Capacity (MW)	Estimated Commission Date
31	Kabeywa HPP	12	2019
32	Kabale Peat	33	2021
33	Karuma HPP	600	2019
34	Muzizi HPP	45	2020
35	Muyembe-Sirimityo HPP	7	2019
36	Nyabuhuka-Mujunju HPP	3	2019
37	Keere Small HPP	6	2020
38	Ngoromwo HPP	6.2	2020
39	Senok Wind Project	20	2020
40	Kikagati HPP Project	16	2018
41	Oriang HPP	392	2024

Source: **ERA**

Cost Outlook

The generation of electricity in Uganda through fossil fuel power plants has generally taken the back sit in the recent years, especially since the commissioning of Bujagali HPP. We anticipate that this will be the same situation in the medium term, given the many renewables in the pipe line. However, we note that some of these thermal plants will have a part to play mainly as an emergence source of supply. The price of oil has steadily reduced from the highs of over USD 140 per barrel on the international market to as low as USD 35 per barrel in 2016.

According to the U.S. Energy Information Administration (EIA), the average price of a barrel of Brent crude oil will rise to USD 79/barrel by 2020. After 2020, world demand will start driving oil prices to the equivalent of USD 141.28/barrel in 2040 (again, in 2013 dollars). Given the above consideration, we shall assume a price of USD 100/ barrel for the plan.

In addition to the oil prices, a number of assumptions were considered for costs of generation projects. ***Table 21*** shows the respective estimates mainly focusing on Capital cost of a plant, Operation and maintenance, Plant Factor and Time of construction of a plant.

***Table 21*: Cost over View by Technology**

	Capital Cost (USD per kW)	O&M Cost (USD per kW/yr)	Plant Factor (%ge)	Construction Time (Months)
Bagasse	2,052.8	191	84%	29
Biogas	4,271.6	182	80%	24
Biomass & MSW	2,976.2	285	85%	24
Geothermal	5,475.8	206	89%	30
Hydro	2,455.8	54	51%	24
Landfill gas	2,044.8	121	85%	24
Solar PV	1,801.3	40	19%	9
Wind	1,737.2	36	29%	19

Source: ERA

5. DEMAND AND SUPPLY BALANCE

5.1. Introduction

In section 3 of this report, a demand forecast was conducted to establish the level of capacity requirement that would be required in the next 10 years. On the other hand, section 4 identified the various energy sources that can be used to satisfy the projected demand. This section brings the two sections; 3 and 4 together and presents the potential surplus or deficit position that may arise from 10-year demand and supply situation thus called the demand supply balance.

5.2. Demand and Supply balance

The Authors of PSIP in their dispatch adopted the spreadsheet based "***Monte Carlo***" simulation model to derive a dispatch that meets the projected demand at the respective time periods. This model uses random number generators to assign respective hours of the years to demand. Then demand is randomly selected in relation to the random numbers and the available generation is dispatched to meet the demand. This method was used in continuous iterative demand events while registering any events of unserved demand under the merit order dispatch.

While the PSIP methodology is observed to be ideal, it is faced with some challenges given the existing energy policy in Uganda. Under the renewable energy policy and the Renewable Energy Feed in Tariff, all small renewable generators have a guaranteed dispatch. As a result, all small renewables have to be dispatched first and there after dispatch the rest of the plants under merit order thus dispatching the cheapest plants first.

We thus developed a demand supply balance as shown in ***Table 22*** for the base case. As illustrated in the ***Table 22*** and ***figure 14***, while the total demand increases from 575 MW to 1,067 MW by 2025, total generation grows from 693 MW to 3,133 MW. This demand supply balance leads to un-utilized generation increasing from 118 MW in 2016 to 2,066 MW in the year 2025.

On the other hand, considering the High Case scenarios, the total demand will grow from 649 MW to 1,849 MW. This will lead to a lower un-utilized supply starting from 44 MW in 2016 including thermal capacity to 1,284 MW in 2025.

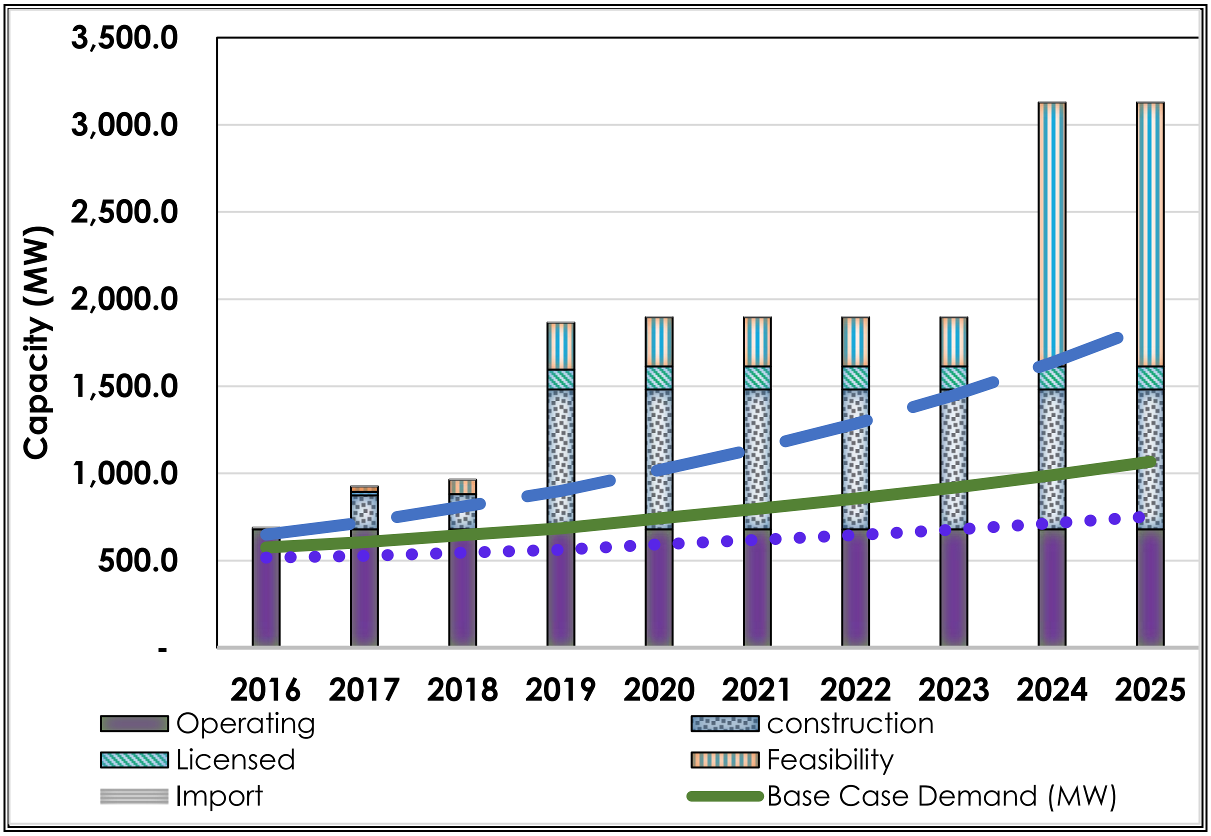
In the same vein, considering a low case scenario will have unutilized generation increasing from 176 MW to 2,380 MW by 2025. As discussed above, considering all the scenarios, it is evident that if all planned generation projects are commissioned as assumed in the study, then Uganda will face a challenge of excess generation capacity if no mitigation measures are undertaken in time. There is thus an urgent need for Uganda to explore avenues of increasing the uptake for electricity generated in order to align demand with supply.

Table 22: **Demand Supply Balance**

Year	Available Supply (MW)	Base Case Demand (MW)	High Case Demand (MW)	Low Case Demand (MW)	Balance Base Case (MW)	Balance High Case (MW)	Balance Low Case (MW)
2016	693	575	649	517	118	44	176
2017	929	605	720	526	324	209	403
2018	967	646	809	546	321	158	421
2019	1,870	684	899	561	1,186	971	1,309
2020	1,901	742	1,018	593	1,159	883	1,308
2021	1,901	796	1,144	619	1,105	757	1,282
2022	2,293	855	1,286	647	1,438	1,007	1,646
2023	3,133	918	1,448	678	2,215	1,685	2,455
2024	3,133	989	1,635	714	2,144	1,498	2,419
2025	3,133	1,067	1,849	753	2,066	1,284	2,380

Source: Computation

Figure 14: **Demand Supply Balance**



Source: ***Internal Computation***

6. WAY FORWARD

In order to address the likely excess capacity challenge, the following are some of the proposals that may help to align Uganda's demand with supply;

6.1. Increase Domestic Demand

As earlier discussed, the industrial sector is the main driver of electricity consumption in the country. It is urgent that all supply constraints are addressed to unlock the suppressed demand within the country. In addition, it is likely that investors have been constrained by the limited infrastructure to facilitate the access to electricity. ***Annex 4*** shows the prospective industrial demand as was reported by Umeme in preparation for the plan.

In line with the Uganda Investment Authority's plan for industrial parks, there is need to support the development of the infrastructure in the Industrial parks in the country. In particular, there is need to fast track the infrastructure required for Namanve Industrial Park. There are two forms of investment required; investment to improve the quality of supply and then increasing the capacity. The required investment in the industrial parks is discussed in detail in the next section.

6.2. Export Opportunities

Preliminary inquiries have indicated that Kenya and Tanzania may have excess capacity in the next 2 to 3 years. However, export opportunities can be sought in Rwanda, Burundi, DR Congo and South Sudan. According to the UETCL Grid Development Plan (2014 -2030), the export potential stands at 390 MW.

Such export opportunities however require investment in transmission infrastructure. Above all, it is capital intensive and has a long lead time. It is therefore important to undertake these investments early in order to meet demand. An estimate of the required investment in the required infrastructure is also discussed further in the next section. Export to neighboring countries would require policy makers and the political heads to come to an agreement to import Uganda's power. An Inter – Ministry Committee is thus needed to explore marketing opportunities in neighboring countries.

6.3. Review the Renewable Energy Policy

The policy provides for a guaranteed dispatch of the renewable generation. While it is important to incentivize the development of renewable energy projects, it may be ideal to revisit the guaranteed generation provision in the policy. This is mainly due to the excess capacity projected.

6.4. Rescheduling of Generation Plants

For projects that are in the initial stage, it is important that these projects are rescheduled to slightly later dates to allow for the exhaustion of the already committed projects that are already under construction.

6.5. Rural Electrification

The RESP (2013-2022) is targeting increased connection of up 26 % which would be approximately 1.28 million connections. We however note that the level of rural electrification attained in the meantime is lower than targeted. It is therefore important that necessary support is accorded to REA in order to fast track its implementation to increase the number of domestic customers.

7. REQUIRED INVESTMENT TO UNLOCK DEMAND

To address the projected demand constraint, there is needed to make investment in the infrastructure both at distribution and transmission level. This will improve the quality of supply, increase the supply capacity or facilitate exports. The following section discusses the required investment to address the demand constraint. These investment requirements have been subdivided into priority areas and these are:

7.1.1. New Connections

The connections were costed based on the "**Last Mile Cost Principle".** Normally new connection costs are based simply on the cost to install the meter and service cable. This omits the required low voltage and distribution transformer costs to support the customer base growth. This approach is not sustainable as it results in under-investment in the low voltage networks leading to poor voltage regulation, long low voltage lines, high technical losses and poor reliability. The last mile costs of a connection were considered to ensure that the customer growth does not result in low voltage networks moving out of technical compliance.

The assumptions for new connections are as follows:

- Customer growth rate: 140 000 per annum
- Specific consumption per annum: 800kWh
- New Domestic customers distribution assumptions: infill no pole: 80%, infill one pole: 15%, greenfield: 5%
- Last mile connection costs: infill no pole $140, infill one pole $500, and green field $1,500
- Annual expenditure $35-$40m

7.1.2. 33/11KV and MV Feeder Growth Investment

This investment addresses the following key growth requirements:

- The distribution assets required for the evacuation of Karuma, Isimba and Get fit projects
- Evacuation of power from all the planned UETCL substations
- Backbone assets to address local industrial and domestic load growth in the demand forecast.

The list of the major projects is attached as **Annex 4.**

7.1.3. Investments to Reduce Poor Power Quality

The power quality has now become a topical issue within industrial customers. The causes of poor power quality range from natural effects such as lighting, system effects such as faults, switching operations and customer effects switching in and out of major loads, like furnaces, large motors etc. The symptoms of the power quality problems are:

- Unexplained equipment trips and shutdown
- Occasional equipment damage and component failure
- Erratic control of process performance
- Power system components over heating

From a power demand side, power quality results in reduction in energy consumed, and from the customer side there is production loss, equipment and material damage. In Uganda, this problem has been experienced by customers in Namanve Industrial Park, Mukwano, Hima, and in Jinja. Umeme proposes an average annual investment of $10m per year to cater for the system generated disturbances.

7.1.4. Total demand Growth Investment at Distribution

When all the above are taken into consideration, the required investments at distribution level to match the transmission investments are estimated to be USD 120 million per annum for the Umeme Network or USD 1.2 billion for the next 10 years.

7.2. Investment in Transmission

Three transmission projects are urgently required in unlocking domestic demand in Uganda; Queensway Substation 132/33kV Project, Mutundwe-Entebbe 132kV line and Industrial Parks 132/33kV Project. These projects aim at supplying power to the increasing domestic demand and upcoming industrial loads. UETCL under their Grid Development Plan estimates a total investment of USD 1,272 million on transmission infrastructure in the next ten years. This investment is required to facilitate the transmission and evacuation of power over the network. Details of the estimated cost are summarized in ***Table 23***.

Table 23: Grid Investment Plan for Additional Substation Projects

Year	**Capacity (MVA)**	**Investments (USDx1000)**
2016	965	341,673
2017	410	258,746
2018	880	305,131
2019	3,845	196,069
2020	440	108,266
2021	40	40,299
2024	80	21,983
Total	**6,660**	**1,272,166**

Source: **UETCL**

Industrial Parks Infrastructure

The Uganda investment Authority (UIA) gazette up to 21 industrial parks in the country that will support the manufactures and all possible industrial developments for prospective investors in processing and value addition. Four industrial parks are under development, these are; Namanve South, Luzira, Mukono and Iganga. As a result of this development, transmission and distribution substations are under construction to support the manufacturing activities.

In order to support this development, a loan of US$84,979,000 was acquired from the China EXIM Bank for the development of the transmission infrastructure. In addition to this loan Government of Uganda contributed up to 24 million towards counterpart funding.

However, a constraint in the release of the counterpart funding on the side of government has been noted to delay the implementation of the project.

On the distribution side, approximately US$23 million will be required to support the transmission capacity under development. This investment is expected to be undertaken privately by Umeme Ltd unless otherwise guided by the Government.

As a result of the developments in the four industrial parks, a total of 451 MW of demand will be released from the manufactures. The details of the planned capacity demand and the resultant distribution cost are shown in the ***Annex 5.***

7.3. Exports Opportunities for Uganda

The Least Cost Generation Plan considered exports to the neighboring countries as one of the options to increase the demand for the generated power. The following is the status of the transmission lines to the neighboring countries;

i) Kenya

The current interconnection line to Kenya was contracted for the main purpose of system stability. As such, it only works on the tie line agreement of exchange of power mainly for stability of either systems at any time. The maximum capacity of this line is 40MW.

In 2014, Rwanda signed a power purchase agreement with Kenya to import up to 100 MW. This power will be wheeled over Uganda's network.

As a result of the planned wheeling over Uganda's network, a wheeling agreement was as well signed between Uganda, Kenya and Tanzania.

Following the wheeling agreement, Uganda embarked on a construction of a 220Kv line that will wheel this power and is expected to be commissioned in late 2017. It is expected that this line will have the capacity to wheel up to 300 MW. This will therefore be an opportunity for Uganda in the medium term to export reasonably high capacities of power to either Rwanda or Kenya.

ii) Tanzania

A feasibility study was conducted and completed under the NELSAP project in 2011 for a transmission line to northern Tanzania. The feasibility study needs to be updated in order to fit in the current status and technical requirement.

There is however no funding or export agreement that has been committed for the development of this line. This consequently constrains the prospects of exporting power to Tanzania .There is, therefore, need for the Government to revisit the option of developing this transmission line.

iii) South Sudan

The feasibility study for this transmission line is planned to be undertaken under the NELSAP program. However, a contribution by the Uganda Government of around US$75,000 to support the development of this study is yet to be made. This is expected to delay the development of this transmission line and therefore any sale of power to South Sudan.

iv) Democratic Republic of Congo

A feasibility study for the development of a transmission line to DR Congo was completed in 2012. There is however no funding that has been committed to the development of this line. Similarly the possibility to export power to DRCongo will be delayed due to delays in the construction of the transmission line to DRCongo.

It is generally noted that the transmission line to DRCongo, Tanzania and South Sudan have limited progress in their prospects for construction and therefore demand from the respective countries is limited. Government of Uganda is therefore requested to fast track the development of these lines alongside bilateral negotiations to sale power to these neighboring countries.

7.4. Rural Electrification

The rural electrification strategic plan was developed with the intention of increasing the number of customers by up to 130,000 per year. If the plan is fully implemented with all the funding requirement fully accessed, an additional 6 MW of demand is expected to be realized. It may be noted that the increase in demand is lower than the main grid demand, due to the consumption of the rural households.

This additional demand if fully realized will help to reduce the expected excess generation capacity in LCGP.

As result of the additional plans to increase demand, the additional demand will be as shown in ***Table 1***. The main drivers for the additional demand is the demand expected from the industrial parks after completion and rural electrification.

Table 1: **Summary of implication of additional information on Demand**

Year	Base Case Demand (MW) Before intervention	Base Case Demand after Intervention (MW)
2016	575	575
2017	605	671
2018	646	902
2019	684	1,190
2020	742	1,498
2021	796	1,552
2022	855	1,611
2023	918	1,674
2024	989	1,745
2025	1,067	1,823

Source: ERA

Annex 1: **INPUT DATA**

Table 1.1: **Real Electricity Tariff per Category in Shs/kWh**

Year	Domestic	Commercial	Medium Industries	Large Industrial	Street Lighting
1991	97	289	96	58	116
1992	101	348	113	56	137
1993	150	385	238	88	303
1994	156	227	129	145	254
1995	119	167	124	155	168
1996	109	157	135	164	175
1997	99	145	122	147	159
1998	101	161	125	162	159
1999	124	183	132	158	199
2000	197	197	197	197	201
2001	215	220	149	319	218
2002	221	232	144	260	215
2003	195	203	214	133	239

Year	Domestic	Commercial	Medium Industries	Large Industrial	Street Lighting
2004	186	179	163	66	176
2005	213	204	179	72	202
2006	397	372	345	174	376
2007	374	350	325	164	354
2008	334	312	290	147	316
2009	295	276	256	130	279
2010	257	239	216	123	225
2011	217	201	182	104	189
2012	258	240	226	154	241
2013	253	236	222	151	236
2014	243	236	222	151	236
2015					

Source*: *UEB and ERA

Table1.2: **Uganda's Real Gross Domestic Product in billions**

Year (s)	**Total GDP**	**Industrial GDP**	**Services GDP**	**GDP per Capita**
1991	5297.4	902.0	2490.9	222.3
1992	5544.1	955.5	2661.7	225.0
1993	5881.5	1036.9	2847.2	230.6
1994	6480.3	1245.4	3161.9	247.8
1995	7008.2	1446.6	3483.8	262.6
1996	7385.9	1690.3	3700.0	271.9
1997	7731.4	1893.0	3938.3	278.3
1998	8507.8	2074.6	4269.6	296.2
1999	9071.1	2248.9	4538.5	306.6
2000	9485.7	2341.2	4786.6	311.9
2001	10319.9	2457.7	5255.0	327.6
2002	11038.7	2689.9	5663.5	344.8
2003	11720.3	2886.7	6090.2	357.8
2004	12391.7	3138.7	6479.7	371.4

Year (s)	**Total GDP**	**Industrial GDP**	**Services GDP**	**GDP per Capita**
2005	13529.2	3658.0	7028.9	399.6
2006	14400.8	3891.7	7718.6	420.2
2007	15401.3	4201.4	8361.9	439.6
2008	16969.5	4846.6	9220.2	475.3
2009	17572.0	4872.8	9725.7	476.1
2010	18685.4	5263.1	10386.7	492.4
2011	19847.0	5739.2	11045.1	509.5
2012	21908.5	6059.3	12732.6	641.9
2013	23005.3	6400.2	13441.4	650.7
2014	2661.4	6805.7	14215.5	689.3

Source: ***UBOS***

Table1.3: **Energy Sales across Each Customer Categories in GWh**

	Domestic	**commercial**	**Medium Industrial**	**Large Industries**
1991	370.1	37.8	54.5	63.2
1992	263.3	39.4	72.6	109.5
1993	272.5	36.2	71.0	96.7
1994	285.5	43.3	76.9	81.8
1995	264.5	49.1	92.6	115.3
1996	366.4	64.3	102.1	143.9
1997	344.3	90.0	107.6	158.6
1998	316.6	99.5	135.5	154.3
1999	307.1	109.7	122.7	162.7
2000	311.8	123.8	201.2	206.2
2001	354.4	177.1	218.6	162.6
2002	475.5	161.9	200.4	272.5
2003	418.0	155.5	220.4	263.3

	Domestic	commercial	Medium Industrial	Large Industries
2004	552.2	136.7	262.4	337.6
2005	331.8	129.1	205.8	348.1
2006	290.2	137.6	173.3	389.0
2007	293.5	151.3	211.2	482.1
2008	327.4	178.7	222.9	549.5
2009	363.7	210.7	232.4	594.1
2010	417.9	242.2	256.2	711.3
2011	397.4	215.0	260.2	859.3
2012	469.5	217.4	341.7	908.7
2013	500.6	258.9	378.4	980.6
2014	538.5	278.5	407.1	1054.9

Source: ***Umeme, UEDCL and UEB Data bases***

Annex 2:

Table 2.1: **TEST FOR LONG RUN RELATIONSHIP (Test for stationarity of Residuals)**

Sales Category	**ADF Residual Results**
Domestic	0.927
Commercial	5.309
Medium Industry	2.792
Large Industry	2.792

***** Critical Values: 1% =-3.75, 5%= -3, 10%=-2.64***

Table 2.2: **TEST FOR STATIONARITY of Variables (Unit Root Test)**

Variable	**Test Statistic Before Differencing**	**Test Statistic After Differencing**
Large Industrial Sales	2.939	-3.879
Commercial Sales	-0.101	-3.606
Medium Industry Sales	0.033	-4.571
Tariff Commercial	-2.098	-3.948
Tariff Medium Industry	-2.455	-5.583
Tariff large industry	-2.531	-3.528
GDP Industrial	2.792	-4.144
GDP commercial	1.577	-2.699

**** Critical Values: 1% =-3.75, 5%= -3, 10%=-2.64**

Table 2.3: **Unit Roots Tests after First Difference**

	Dickey-Fuller test for unit root			Number of obs = 21
		Test Statistic	1% Critical Value	5% Critical Value	10% Critical Value
Energy	Z(t)	-4.555	-3.750	-3.000	-2.630
GDP	Z(t)	-4.166	-3.750	-3.000	-2.630
Tariff	Z(t)	**-2.891**	-3.750	-3.000	-2.630

Table 2.3: **Stationarity Test of Residual with Regression of Energy Sales, Tariff and GDP only**

Dickey-Fuller test for unit root			Number of obs = 22	
	Test Statistic	1% Critical Value	5% Critical Value	10% Critical Value
Z(t)	2.318	-3.750	-3.000	-2.630

Source: ERA

Table 2.4: **Stationarity Test of residual with Regression of Energy Sales and GDP only, lags (0)**

```
Dickey-Fuller test for unit root                 Number of obs   =      22
                    ---------- Interpolated Dickey-Fuller ---------
            Test         1% Critical       5% Critical      10% Critical
          Statistic        Value             Value             Value
------------------------------------------------------------------------------
 Z(t)        5.286         -3.750           -3.000            -2.630
------------------------------------------------------------------------------
```

Annex 3: **REGRESSION RESULTS**

	Const	**Tariff**	**GDP**	**N**	**F**	**Adj.R^2**
Large Industry	-5.887 (0.000)	-0.235 (0.007)	1.370 (0.000)	24	335.58	0.967
Commercial	-4.768 (0.000)	-0.285 (0.078)	1.211 (0.000)	24	103.84	0.899
Medium Industry	-3.229 (0.000)	-0.135 (0.375)	0.894 (0.000)	24	97.12	0.893

Annex 4: DETAILS OF COMMITTED AND CANDIDATE GENERATION PROJECTS

No.	Project Name	Technology Option	Installed Capacity (MW)	Estimated Plant Factor	Comment	Estimated Commission Date
1.	Access Solar	Solar	10	19%	Under construction and qualified for GETFiT premium	2017
2.	Isimba HPP	Hydro	183	67%	Under construction as a public project. Oversight activities undertaken by MEMD.	2018
3.	Rwimi HPP	Hydro	5.54	50%	Under construction and qualified for a premium under the GETFiT.	2017
4.	Lubilia HPP	hydro	5.4	50%	Under construction and qualified for GETFiT Premium.	2018
5.	Muvumbe HPP	hydro	6.5	50%	Under construction and qualified for GETFiT Premium.	2017

No.	Project Name	Technology Option	Installed Capacity (MW)	Estimated Plant Factor	Comment	Estimated Commission Date
6.	Waki Hydro HPP	hydro	4.8	50%	Under construction and qualified for GETFiT Premium.	2018
7.	Siti 1 HPP	Hydro	5	50%	Under construction and qualified for GETFiT Premium.	2017
8.	Mahoma HPP	hydro	3	50%	Licensed. Expected construction start 2017	2018
9.	Nkusi HPP	hydro	9	50%	Licensed. Started construction in 2016	2017
10.	Emerging power	Solar	10	20%	Licensed	2017
11.	Albatros Thermal Power	crude oil	50	90%	Licensed to use local crude oil from Albertine region.	2021
12.	Sindila HPP	hydro	5.25	50%	Licensed and under construction.	2018

No.	Project Name	Technology Option	Installed Capacity (MW)	Estimated Plant Factor	Comment	Estimated Commission Date
13.	Nengo Bridge HPP	hydro	6.7	50%	Under construction and qualified for GETFiT Premium	2019
14.	Nyamwamba HPP	hydro	9.2	50%	Licensed and Under construction.	2017
15.	Kakaka HPP	Hydro	5	50%	Licensed	2018
16.	Agago-Achwa HPP (ARPE)	hydro	83	50%	Licensed. Expected construction start, Q1 2016	2018
17.	Nyagak III HPP	hydro	4.36	50%	Licensed. Expected construction start, 2017	2018
18.	Kyambura HPP	hydro	8.3	50%	Licensed and qualified for GETFiT premium. Expected construction start, 2017	2018
19.	Sironko HPP	hydro	7	50%	Feasibility studies ongoing	2019
20.	Nyamagasani 2 HPP	hydro	8	50%	Feasibility studies ongoing	2018

No.	Project Name	Technology Option	Installed Capacity (MW)	Estimated Plant Factor	Comment	Estimated Commission Date
21.	Nyamagasani HPP 1	hydro	15	57%	Feasibility studies ongoing.	2021
22.	Lake Albert Natural Gas Project	Natural Gas	50	50%	Feasibility studies ongoing.	2019
23.	Bukinda HPP	hydro	6.5	44%	Licensed Expected construction start, 2017	2018
24.	Kabeywa HPP	hydro	12	50%	Feasibility Study ongoing.	2019
25.	Ndugutu HPP	hydro	5.1	50%	Licensed, Expected construction start, 2017	2018
26.	Tororo PV Solar	Solar	10	23%	Licensed, Expected construction start, 2017	2017
27.	Kabale Peat	peat	30	70%	Feasibility Study ongoing	2021
28.	Karuma HPP	Hydro	600	65%	Under construction as a public project.	2019
29.	Muzizi HPP	hydro	44.7	70%	Feasibility study complete	2020

No.	Project Name	Technology Option	Installed Capacity (MW)	Estimated Plant Factor	Comment	Estimated Commission Date
30.	Siti 2 HPP	Hydro	16.5	50%	Licensed. Expected construction start, 2016	2018
31.	Muyembe-Sirimityo HPP	hydro	6.9	50%	Feasibility studies on-going	2019
32.	Nyabuhuka-Mujunju HPP	hydro	3.2	50%	Feasibility studies on-going	2019
33.	Bukwa HPP	hydro	9	50%	Feasibility studies ongoing.	2019
34.	Keere Small HPP	hydro	6.3	50%	Feasibility studies on-going	2020
35.	Ngoromwo HPP	hydro	8	50%	Feasibility studies on-going	2020
36.	Senok Wind Project	wind	20	30%	Feasibility studies on-going	2020
37.	Oriang HPP	Hydro	392	65%	Feasibility studies on-going	2024
38.	Kikagati HPP Project	hydro	16	55%	Licensed. Expected construction start, 2017	2018

ANNEX 5: ADDITIONAL INDUSTRIAL DEMAND

	Customer	Additional load (MW)	Location	Time lines
1.	Roofings (Namanve) – 43MW	28	Mukono	2017
2.	Tian Tang Steel Works (Mbalala) – 10MW (up to 30MW)	26	Mukono	2017
3.	Tembo Steels at Lugazi	14	Lugazi	2017
4.	Tembo Steels at Iganga	12	Iganga	2017
5.	Kampala Cement Industries	10	Lugazi	2017
6.	Abisha Steel	10.5	Lugazi	2017
7.	Steel Corporation of East Africa	16	Jinja	2017
8.	Nile Breweries Jinja	4	Jinja	2017
9.	MMI Steel	2	Jinja	2017
10.	Bidco	5	Jinja	2017
11.	Other factories around Jinja Industrial (Bidco area)	20	Jinja	2017
12.	Pramukh	7	Kayunga	2017

	Customer	Additional load (MW)	Location	Time lines
13.	Yogi	2	Kayunga	2016
14.	DAO Cement	25	Mbale	2017
15.	Bavima	2	Jinja	2017
16.	China Golden Rooster	7	Bombo	2017
17.	National Water - Katosi	30	Mukono	2017
18.	Mbale Cement - phased	5	Mbale	2017
19.		5	Mbale	2016
20.		5	Mbale	2019
21.		5	Mbale	2021
22.		9.7	Entebbe	2016
23.		27	Entebbe	2020
24.	NSSF Lubowa Housing Estate	27	Najjanankumbi	2020
25.	Mukwano	14	Banda	2017
26.	Steel and Tube Industries	25	Banda	2017
27.	Three Way Shipping	10	Banda	2017
		378.7		

Source: ***Umeme***