RWANDA LEAST COST POWER DEVELOPMENT PLAN (LCPDP) 2019 – 2040

June 2019

EXECUTIVE SUMMARY

This document provides a least cost generation expansion plan for Rwanda's electricity system.

The Development of the Least Cost Power Development Plan (LCPDP) was undertaken as part of the key exercises under the REG Reform programme that buildings on earlier work that had been carried in 2014.

The purpose of the plan is to have a systematic development of the Rwanda Generation Resources prioritizing the least cost options so as to ensure that the tariff affordability objectives are being optimized.

The least cost study has been segmented into two phases - the immediate period (**2019 – 2025**[1]) and **2026 – 2040**[2], in line with the long-term nature of energy infrastructure investments.

The results within this report provide a least-cost optimal development path which still meets the forecasted electricity demand. This is expected to propel the country's economic growth, both in terms of providing support for the emerging industry sector and improving the standard of living for Rwanda's citizens.

Until the Hakan peat to power facility begins operation in 2020, Rwanda will have limited generation resources especially during the dry season when many hydro power plants face water shortage problems. During this period, rental diesel generation is used to supply the peak demand, and this generation comes at a high cost. The optimal expansion program indicates that there is an immediate need for the import of approximately 45 MW in the last half of 2019, based on an estimated annual uniform electricity demand growth of 10%.

This generation expansion plan is based on entry of both government generation projects and agreements with private developers. Acceleration of privately-funded generation expansion can significantly reduce on the need for government direct investment. However, this also increases the possibility of increased electricity tariffs and consequent losses incurred by the national power utility, especially if the terms of the power purchase agreements (PPA's) do not match the interests of both parties. REG and Government should therefore use as the least-cost entry dates, technologies and capacities of committed (signed PPA's) generation plants.

Least-cost generation expansion results show the emergence of natural gas-fired[3] power plants and hydro pumped storage in the longer term. Further research into pumped storage potential in the Rwanda should be carried out, as well as more information given, concerning the amount of natural gas to be imported from the planned Tanzania-Rwanda pipeline connection.

[1] Consisting of already-committed power projects.
[2] Period of least-cost addition of pipeline projects and new potential supply technologies.
[3] Import of natural gas through a pipeline from Tanzania to Rwanda.

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List of Abbreviations

BAU	Business as Usual
CF	Capacity Factor
CIF	Cost, Insurance & Freight
CNSE	Cost of Non-Served Energy
CoD	Commercial Operation Date
EDPRS	Economic Development and Poverty Reduction Strategy
ESSP	Energy Sector Strategic Plan
HPP	Hydro Power Plant
IAEA	International Atomic Energy Agency
IPP	Independent Power Producer
MESSAGE	Model for Energy System Supply Alternatives & their Environmental Impact
MININFRA	Ministry of Infrastructure
NEL	Nile Equatorial Lakes
NELSAP	Nile Equatorial Lakes Subsidiary Action Programme
PP	Power Plant
PPA	Power Purchase Agreement
REG	Rwanda Energy Group
RES	Renewable Energy Share
TBD	To Be Determined
T&D	Transmission & Distribution
tCO_2 eq	Tonnes of carbon dioxide equivalent

1. Introduction

Electricity availability and consumption is a critical input for economic, social and political development of a country. It is therefore of utmost importance that a country has adequate and reliable electricity supply to meet its demand, based primarily on the existing resources. The development of a least-cost generation development plan provides a realistic guide as to how demand for electricity can be met in the medium and long-term at a minimized cost.

The main policy objectives for the electricity generation sector were declared by the Government of Rwanda within its energy policy on March 2015:

" To ensure sufficient, reliable, sustainable and more affordable power supply. This will be achieved through the following measures:

i. Revise and upgrade the existing policy, legal, regulatory, institutional, and financial frameworks to support the rapid development of the electricity industry;
ii. Diversify power generation resources over time and increase the share of clean power in the total mix over time;
iii. Ensure supply is closely aligned to projected demand, and better align investment planning and funding mobilization more closely to a power generation road map and master plan, a least-cost power development plan, and an electricity sub-sector action plan;
iv. Enhance regional cooperation and trade in electricity, including investment in transmission network development, to further improve security of supply;
v. Streamline IPP processes and fast track project delivery by securing long-term funding for planned projects, through a medium-term budget expenditure framework, revising and expanding the existing Renewable Energy Feed-In Tariff regime, developing new information management systems to streamline procedures, and building greater capacity in planning, procurement, and negotiating power transactions."

The main objective of the Rwanda generation master plan, therefore, is to satisfy the forecasted growing demand for electricity within the country while maintaining an acceptable operational reserve margin. The study described in this document is based on the least-cost generation expansion planning methodology and has been conducted from the perspective of the national economy, complying with the appropriate operational and reliability considerations.

Other objectives of the plan include:

i. Maximisation of the use of renewable energy within the country's energy mix.
ii. Optimisation of the availability of electricity supply to meet peak demand and avoid the possibility of generating excess capacity.
iii. Adherence to the Rwandan energy policy[4] and the energy sector strategic plan (ESSP)[5] that highlight the need for a least cost power development plan to guide power generation capacity increase and investments.

[4] Rwanda Energy Policy: http://www.mininfra.gov.rw/fileadmin/user_upload/new_tender/Energy_Policy.pdf.
[5] ESSP: http://mininfra.gov.rw/fileadmin/user_upload/new_tender/Energy_Sector_Strategic_Plan.pdf.

The following section provides a brief overview of Rwanda's energy sector. **Section 3** discusses the demand forecast, while **sections 4** and **5** cover the existing and planned generation plants within Rwanda. **Section 6** provides the least cost planning methodology, generation expansion scenarios and presents the software that was used, while **section 7** outlines and provides a discussion of the least cost results obtained from the least cost modelling. Conclusions and recommendations are outlined in section 8.

2. Rwanda Energy Sector Overview

Rwanda is a land-locked country with a surface area of 26,338 km^2 and a growing population of 12,756,625[6]. It is densely populated with a 2016 GDP at 729 (constant) 2016 USD/capita[7]. Rwanda's economy has been growing at an annual average rate of 8.3% and government is targeting an annual average growth rate of 11.5% over the EDPRS II period (2013-2018). Ensuring 100% access to affordable and modern sources of energy is essential to achieve this target.

Rwanda's energy sector consists of different players with different roles to play as specified within the Rwanda grid code.

Figure 1 provides an overview of the energy sector operating in the country at present.

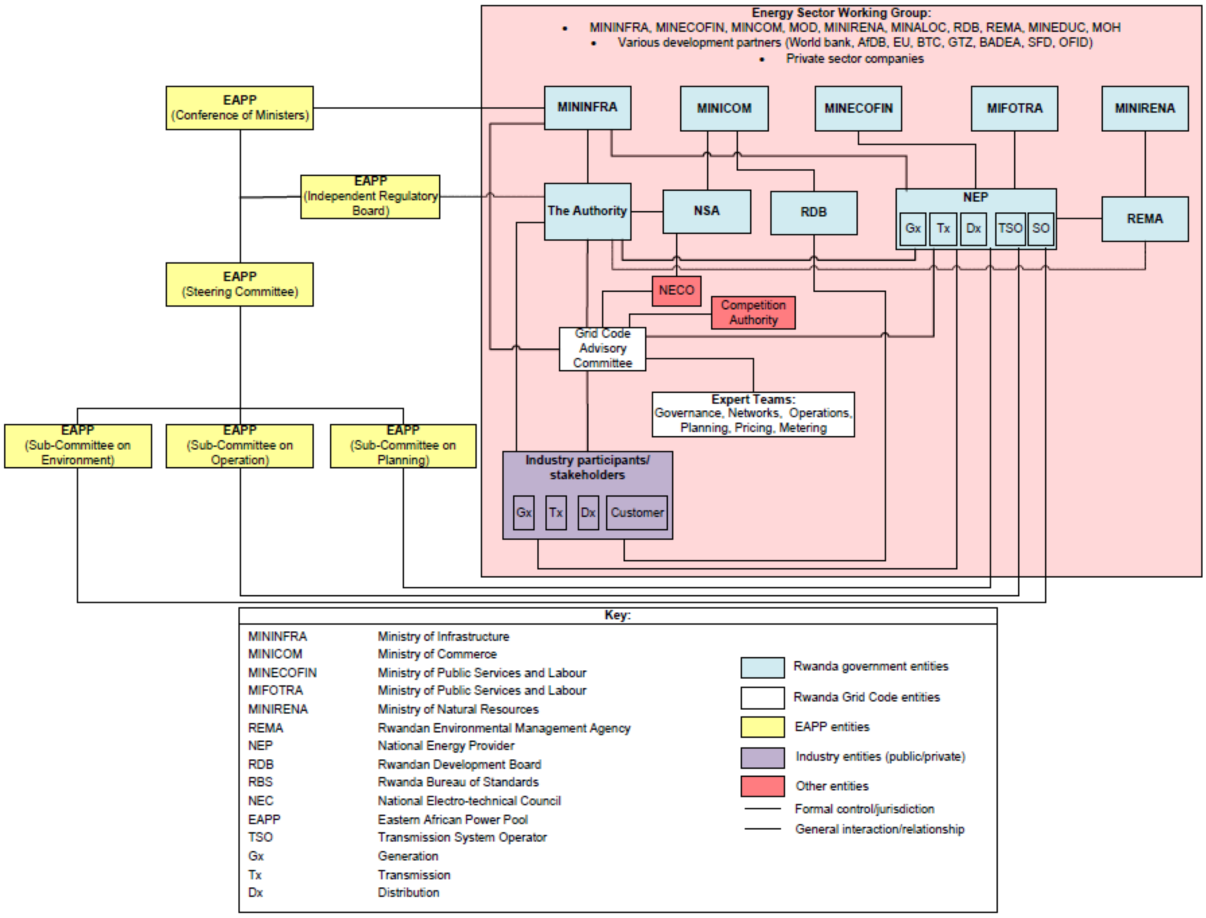

Figure 1: Rwanda's Current Energy Sector Structure[8]

State-owned Rwanda Energy Group (REG) was incorporated in 2014 to expand, maintain and operate the energy infrastructure in Rwanda through its two subsidiaries – the Energy Utility Corporation (EUCL) and the Energy Development Corporation (EDCL). Within this framework, planning of generation and transmission as well as electrification projects is the joint responsibility of the Ministry of Infrastructure (MININFRA) and the REG.

[6] NISR 2017 Statistical Yearbook.
[7] NISR 2017 Statistical Yearbook.
[8] Figure obtained from the Rwanda Grid Code

3. Demand Forecast

Demand forecasts estimate the amount of electricity needed in the country or geographic area served by the power system. Generation expansion planning requires a demand forecast, typically from 5-30 years into the future. A demand forecast enables optimum planning for when, how much and what type of generation technologies must be added onto an existing power system. Transmission and distribution systems expansion planning also benefit from demand analysis and forecasts.

Typical information required to perform an extensive demand analysis and forecast include:

i. Historical records of electricity sales by consumer category and geographical area.

ii. Chronological demand records over days, weeks, months and years are required to determine the relationship between electricity sales and the amount of generation capacity required. The load profile is used to determine what types of generating capacity are needed.

iii. Economic and demographic historical data on economic performance and population.

iv. Economic and demographic projections of either the power utility, an economic planning ministry or from some other governmental entity.

v. Energy end-use data, e.g. percentage of different consumer categories that use specific electric appliances and the amount of electricity used per customer per end use.

Methods used to forecast demand include **trending**, **econometric analysis**, **end-use simulation**, and/or appropriate combinations of all three.

Trend forecasting assumes that past rates of electricity use per consumer category, will grow at a uniform rate. A growth rate calculated from historical data (sales or peak demand data) may be applied to estimate future consumption and demand. Separate trending forecasts can be compiled for each customer class or geographic division. Trend forecasting requires only access to basic sales and peak statistics, and the use of simple statistical methods. However, the exclusive use of trend forecasting eliminates incorporation of certain demand growth rate drivers such as changes in technology, structural shifts in the economy or demography, and/or regulatory changes. Trending is most applicable within short-term forecasting (1-2 years).

Econometric forecasting investigates statistically significant historical relationships between economic variables and electricity sales or peak demand. Variables used to develop econometric relationships may include household income, electricity prices (by consumer group), prices for other household necessities, employment rates (by sector and sub-sector), labour productivity, tourism, industrial or agricultural output (measured in physical quantities or monetary terms), commercial-sector output (by sub-sector), use of other fuels, and the prices of other fuels. Different statistical procedures can be used to test how accurately changes in one or more independent variables predict the value of the quantity to be forecast. In addition to testing the statistical significance of these relationships, econometric tools allow calculating the mathematical relationships among parameters. Once these statistically significant economic or demographic variables that affect electricity use or demand are identified and specified, projections for the driving variables are developed. These projections are used to derive the econometric forecasts of electricity use or peak demand. Factors that influencing electricity demand differ amongst different consumer categories. Therefore, econometric forecasts for electric energy use (as opposed to peak demand), are typically performed separately for each major consumer group, then aggregated to estimate system-wide sales.

End-use forecasting builds up estimates of electricity needs starting with an analysis of what electricity is used for by the different consumer categories. An end-use model of household electricity use might include separate estimates of electricity used for lighting, water heating, space heating, air conditioning, fans, cooking, entertainment, and other appliances. Using the example of air conditioning, one can specify a relationship between end-use variables:

$$Electric\ Energy\ Use\ for\ Air\ Conditioning = H \times F \times AC \times EI$$

Where: *H* = Number of households

F = Fraction of households with air conditioners

AC = Amount of cooling required per household

EI = Energy intensity of average air conditioner model in use

In this example, one can forecast energy usage by projecting each of the four parameters on which air conditioning electricity usage depends. End-use forecasts can be prepared using spreadsheet software, or using customized forecasting software packages[9], which are widely available.

End-use approaches have several advantages. They can be quite detailed, providing more information for planners. They provide integrated forecasts of both energy and peak power demands. The assumptions used in forecasting are usually easy to follow, check, and revise as new data become available. End-use forecasts provide an excellent framework for estimating the impacts of energy-efficiency options and demand-side management by making changes to parameters used in the baseline forecast. In the example used above, for instance, the analyst can change the assumed energy intensity of air conditioners to reflect introduction of more efficient units. On the other hand, end-use forecasts are extremely data-intensive. Surveys of different types of buildings are usually needed to collect good data on energy end-uses.

Demand analysis methodologies vary depending on the availability and granularity of data available. Selection of an appropriate demand analysis methodology depends on the availability and specificity of data available, i.e. end-use forecasting methods is best used once end-use data is comprehensive and available, while trending can serve as appropriate for countries whose demand grows with increased electrification rate as is the case for Rwanda.

Since the future is inherently uncertain, a base case is prepared along with several alternative (high and low growth scenarios) forecasts of energy and peak demand. The base case might be the best annual growth estimate with the alternatives catering to visionary projections such as high or low economic and/or population growth assumptions. These alternative scenarios

[9] E.g. the International Atomic Energy Agency (IAEA) developed tool – Model for Analysis of Energy Demand (MAED).

provide room for sensitivity analyses, i.e. an assessment of the impact of changes in the assumed value of key parameters and can be used to evaluate whether the base scenario is sufficiently flexible for cost-effective modification, even if demand is higher or lower than anticipated.

A study done by the Rocky Mountain Institute revealed a direct (1:1) correlation between GDP growth and growth in electricity consumption per capita in Rwanda as shown in 13-year historical data in *figure 2*.

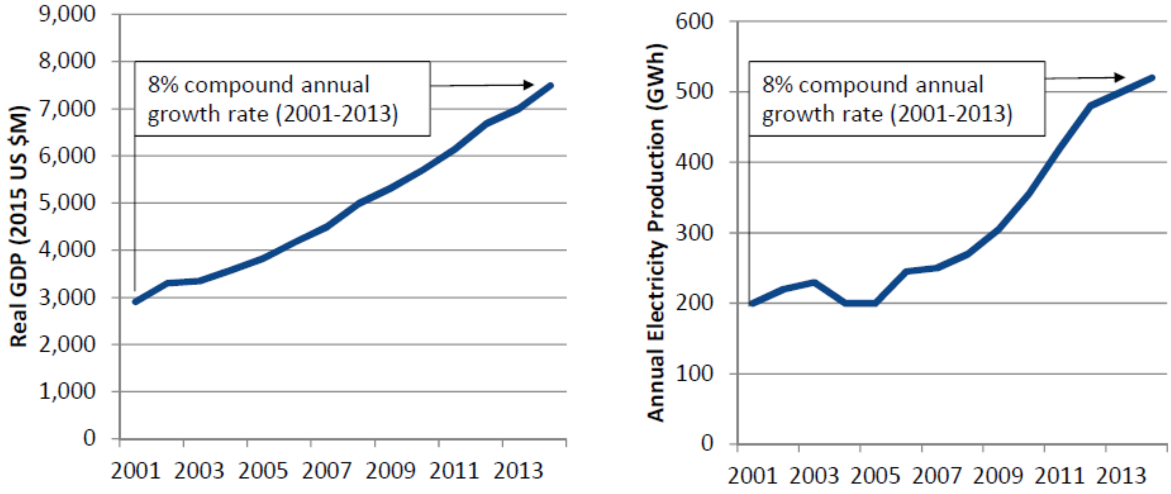

Figure 2: Rwanda Historical GDP and Electricity Consumption Data

An additional study conducted by Israel Electric considered different annual growth rates of 8% (*low growth*), 10% (*base case*) and 12% (*high growth*) due to the uncertainty of forecasts. Electricity demand forecasts were then calculated in line with recent historical trends, using existing hourly load curves for the years 2015-2016. Peak and energy demand forecasts over the next 20 years were calculated as shown in *table 1*.

Table 1: Annual Peak & Energy Demand Growth for Different Growth Rates

Years	Scenario: 8% growth		Scenario: 10% growth		Scenario: 12% growth	
	Peak, MW	Energy, GWh	Peak, MW	Energy, GWh	Peak, MW	Energy, GWh
2016	119	715	119	715	119	715
2017	129	772	131	787	133	801
2018	139	834	144	865	149	897
2019	150	901	158	952	167	1005
2020	162	973	174	1047	187	1125
2021	175	1051	192	1152	210	1260
2022	189	1135	211	1267	235	1411
2023	204	1225	232	1393	263	1581
2024	220	1323	255	1533	295	1770
2025	238	1429	281	1686	330	1983
2026	257	1544	309	1855	370	2221
2027	277	1667	340	2040	414	2487
2028	300	1800	373	2244	464	2786
2029	324	1945	411	2468	519	3120
2030	350	2100	452	2715	582	3494
2031	377	2268	497	2987	651	3914
2032	408	2450	547	3285	730	4383
2033	440	2646	601	3614	817	4909
2034	476	2857	662	3975	915	5498
2035	514	3086	728	4373	1025	6158
2036	555	3333	801	4810	1148	6897
2037	599	3599	881	5291	1286	7725
2038	647	3887	969	5820	1440	8652
2039	699	4198	1066	6402	1613	9690
2040	755	4534	1172	7043	1806	10853

An additional econometric assessment and forecast of annual consumption growth rates based on the available data on residential consumer consumption levels and electrical appliance use provided an estimate of 9.8% for the years 2016-2040. **Bearing the uncertainties associated with demand forecasting and the different results presented by these studies, it was decided that an annual demand growth rate of 10% be used for Rwanda's generation expansion scenario development and expansion planning**. *Figure 3* illustrates the forecasted 10% energy and peak demand growth.

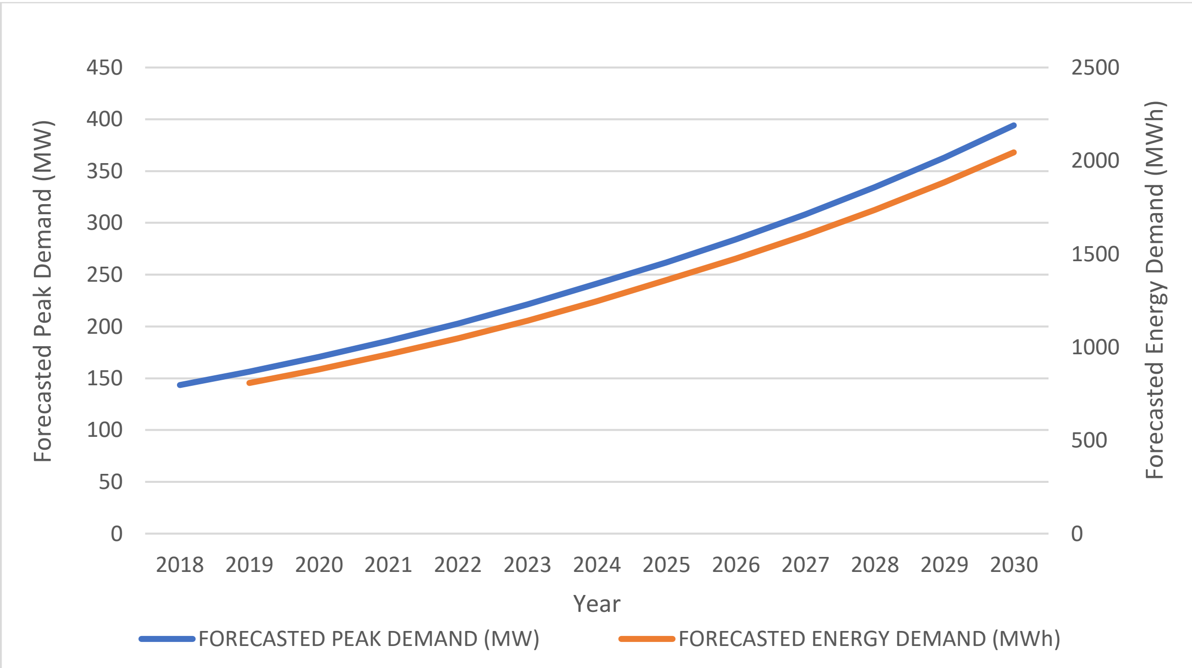

Figure 3: Forecasted Peak Demand vs Installed Capacity (MW)

4. Existing Generation Plants

Table 2 provides a list of the existing generation plants within Rwanda, as well as their associated characteristics.

No	Plant Name	Installed Capacity (MW)	Capacity Factor (%)	Available Capacity (MW)	Owner	COD	Type of Technology
1	Ntaruka	11.25	23	2.5875	GoR	1959	Hydro
2	Mukungwa I	12.00	50	6	GoR	1982	Hydro
3	Nyabarongo I	28.00	48	13.44	GoR	2014	Hydro
4	Gisenyi	1.20	65	0.78	Prime Energy	1957	Hydro
5	Gihira	1.80	70	1.26	RMT	1984	Hydro
6	Murunda	0.1	45	0.045	Repro	2010	Hydro
7	Rukarara I	9.5	40	3.8	Ngali Energy	2010	Hydro
8	Rugezi	2.6	50	1.3	RMT	2011	Hydro
9	Keya	2.2	50	1.1	Adre Hydro&Energicotel	2011	Hydro
10	Nyamyotsi I	0.1	60	0.06	Adre Hydro&Energicotel	2011	Hydro
11	Nyamyotsi II	0.1	60	0.06	Adre Hydro&Energicotel	2011	Hydro
12	Agatobwe	0.2	35	0.07	Carera-Ederer	2010	Hydro
13	Mutobo	0.2	45	0.09	Repro	2009	Hydro
14	Nkora	0.68	50	0.34	Adre Hydro&Energicotel	2011	Hydro
15	Cyimbili	0.3	50	0.15	Adre Hydro&Energicotel	2011	Hydro
16	Gaseke	0.582	90	0.5238	Novel Energy	2017	Hydro
17	Mazimeru	0.5	49	0.245	Carera-Ederer	2012	Hydro
18	Janja	0.2	80	0.16	RGE Energy UK ltd	2012	Hydro
19	Gashashi	0.2	40	0.08	Prime Energy	2013	Hydro
20	Nyabahanga I	0.2	55	0.11	GoR	2012	Hydro
21	Nshili I	0.4	60	0.24	GoR	2012	Hydro
22	Rwaza Muko	2.6	60	1.56	Rwaza HydroPower Ltd	2018	Hydro
23	Musarara	0.45	49	0.2205	Amahoro Energy	2013	Hydro
24	Mukungwa II	2.5	73	1.825	Prime Energy	2013	Hydro
25	Rukarara II	2.2	52.5	1.155	Prime Energy	2013	Hydro
26	Nyirabuhombohombo	0.5	35	0.175	RGE Energy UK ltd	2013	Hydro
27	Giciye I	4	40	1.6	RMT	2013	Hydro
28	Giciye II	4	40	1.6	RMT	2016	Hydro
29	Ruzizi II	12.00	89	10.68	GoR	1984	Hydro
	S-total	**103.16**		**51.26**			**Hydro**
30	Jabana 1	7.8	95	7.41	GoR	2004	Diesel
31	Jabana 2	21	95	19.95	GoR	2009	HFO-Diesel
32	So Energy	30	95	28.5	So Energy&SP	2017	Diesel
	S-total	**58.8**		**55.86**			**Diesel**
33	Gishoma	15	95	14.25	GoR	2016	Peat
	S-total	**15**		**14.25**			**Peat**
34	Biomass (Rice Husk)	0.07	95	0.0665	Novel Energy	2016	Biomass
	S-total	**0.07**		**0.0665**			**Biomass**
35	Kivuwatt Phase I	26.4	100	26.4	Contour Global	2016	Methane
	S-total	**26.4**		**26.4**			**Methane**
36	Jali	0.25	14	0.04	Mainz Stadwerke/Local Agency	2007	Solar
37	GigaWatt	8.50	14	1.19	Gigawatt Global	2013	Solar
38	Nyamata Solar	0.03	35	0.01	NMEC Nyamata	2009	Solar

39	Nasho Solar PP	3.30	20	0.66	GoR	2017	Solar
	S-total	**12.08**		**1.90**			**Solar**
40	Ruzizi 1	3.50	100	3.50	Snel Sarl	1957	Imports
41	UETCL	2.00	100	2.00	UETCL	2016	Imports
	S-total	**5.50**		**3.50**			**Imports**
	Grand Total	**221.9**		**154.1**			

Table 2: Existing Generation Plants

The resulting energy mix is shown in *figure 4*. Currently, thermal units, especially diesel, contribute a big share to the installed capacity of the Rwandan system. These units, however, are only operated during peak hours due to their high operation cost. REG ensures maximum use of cheaper hydro power options, but this presents challenges during the dry season.

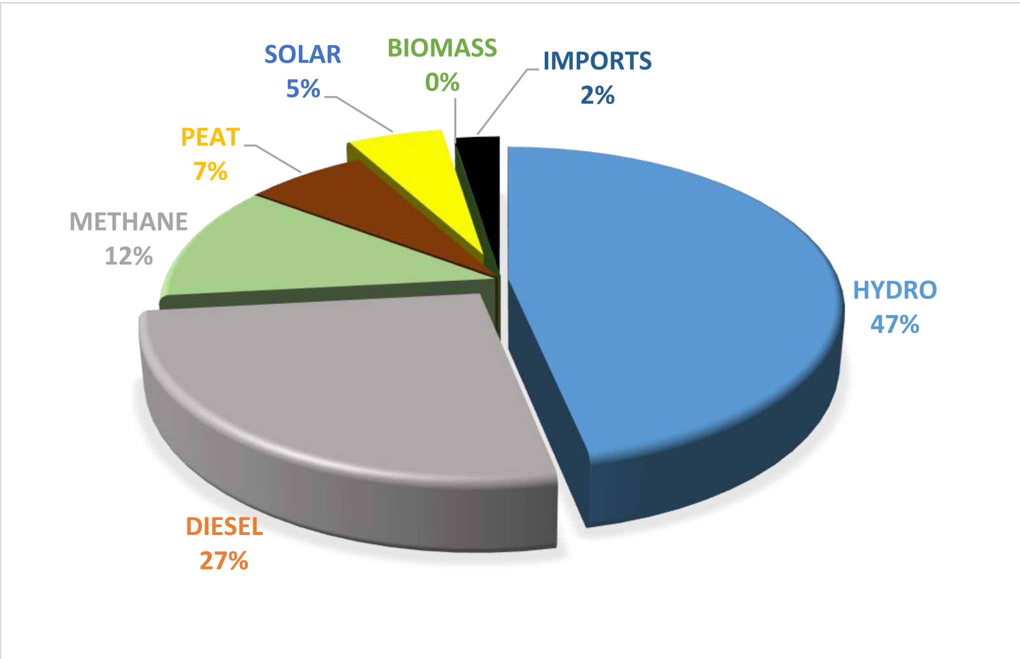

Figure 4: Rwanda's Current Energy Mix

5. Planned Generation Projects

To reduce the high levels of dependence on diesel power generation, different generation expansion scenarios were created and modelled envisioning the use of different technologies to generate electricity on the Rwandan grid. Commissioning dates of key near-term planned projects (outlined in *table 3*) were also used to determine an optimal generation mix for the country.

Table 3: Existing & Planned Generation Projects[10]

#	Power Station	Nominal Capacity (MW)	Planned COD
	Non-renewable power plants		
1	Hakan	80	2020
2	Symbion	50	2022
3	Symbion Extension	25	TBD
4	Kivuwatt	26.4	2015
5	Jabana 1&2	27.8	2004 & 2009
6	SO-Energy	30	2017 - 2019
	Solar Power plants		
1	Gigawatt global	8.5	2013
2	Nasho solar	3.3	2017
	Hydro Stations<=5MW		
1	Agatobwe	0.2	2010
2	Base 1	2.9	2024
3	Base 2	2.9	2024
4	Gisenyi	0.7	1957
5	Kabavu	0.1	TBD
6	Kavumu	0.4	TBD
7	Kigasa	0.2	2019
8	Kore	1.3	TBD
11	Muhembe	0.3	2019
12	Mukungwa 2	1.0	2013
13	Mutobo	0.8	2019
14	Ngororero	2.7	2024
15	Ntaruka A	2.1	2021
16	Nyirahindwe I&II	1.2	2019
17	Nyirantaruko	1.3	2019
18	Nyundo	4.0	TBD
19	Rubagabaga	0.3	2019
20	Rucanzogera	1.6	TBD
21	Rugezi	1.1	2018
22	Rukarara V	5.0	2020
23	Rukore	2.0	TBD
24	Rwondo	2.3	2022
	Hydro Stations>5MW		
1	Bihongore	5.35	TBD

[10] TBD = To Be Determined

2	Giciye III	7.2	2021
3	Nyabarongo II	37.5	2024
4	Rukarara VI	6.7	2020
	Regional Projects (hydro)		
1	Rusizi III	48.3	2025
2	Rusumo	26.7	2021

The large power projects <u>that have been committed and are currently under construction and/or significantly far in their project development cycle</u> during the short term (2019 – 2025) are outlined in *table 4*.

Table 4: Committed Power Plants (2019 - 2025)

#	Power Station	Installed Capacity (MW)	Firm Capacity (MW)	Technology Type	Planned COD
1	Hakan	72	68.4	Peat	2020
2	Nyabarongo II	43.5	28.3	Hydro	2024
3	Rusumo	26.7	25.4	Hydro	2021
4	Rusizi III	48.33	45.9	Hydro	2026
5	Symbion I	50	47.5	Methane	2023
6	Others	43.80	21.73	Mixt	2024
	TOTAL	**506.20**[11]	**390.36**	**N/A**	**N/A**

In addition, the following small HPPs are scheduled for commissioning in the fiscal year 2019/2020.

Table 5: Power Plants to be Commissioned in 2019/2020

#	Power Station	Installed Capacity (MW)	Available Capacity (MW)	Technology Type	Planned COD
1	Rubagabaga (IPP)	0.28	0.2	Hydro	2019
2	Nyirantaruko (IPP)	1.263	0.4	Hydro	2019
3	Muhembe (IPP)	0.323	0.2	Hydro	2019
4	Kigasa (IPP)	0.195	0.1	Hydro	2019
5	Mushishito (IPP)	2	1	Hydro	2019
6	Rukarara V (IPP)	3	2	Hydro	2020
	TOTAL	**7.06**	**3.9**	**N/A**	**N/A**

Both the committed and soon-to-be commissioned power plants (*tables 4* and *5*) were hard-wired into the least-cost software, i.e. with definite commercial operation dates (CODs).

[11] The total Capacity by 2025 is the summation of current installed capacity and planned generation

Therefore, 100% least-cost addition of generation capacity begins from 2026 until the end of the planning horizon (2040).

5.1. Planning Alternatives for Generation System Expansion

In selecting appropriate technological supply alternatives for the expansion of the Rwandan electricity generation system, the following important aspects are to be considered:

- Rwanda is endowed with a myriad of natural resources, the most dominant of which include water, sunshine, methane at the bottom of Lake Kivu and peat reserves in the southern part of Rwanda. It is therefore important that these resources are identified and utilized for electricity production in the most cost-efficient manner, while meeting demand and reserve margin needs. This LCPDP is dedicated to identifying the potential output from maximum and economically feasible utilization of national resources, based on cost variables such as extraction costs/emissions constraints, where applicable.
- Currently, peak demand and reserve during peak are served by mainly diesel-powered power plants (Jabana II, Jabana I and 10 MW of SO Energy), as well as seasonal inputs from the big hydro storage power plants on the system. The use of diesel during these hours hikes up the generation cost, and consequently the electricity tariff. Due to the existence of the Shango-Mirama interconnecting line from Rwanda to Uganda, the possibility of import of power from Uganda to reduce the generation cost prior to Hakan entry in 2020 was considered.
- A power network analysis[12] was done on existing and planned interconnectors (including planned power plants per technology type per country), amongst the 6 Nile Equatorial Lakes Subsidiary Action Plan (NELSAP) member countries, i.e. Burundi, Democratic Republic of Congo, Kenya, Rwanda, Tanzania and Uganda to evaluate the potential future behaviour of the interconnected system over the period 2016 – 2021. Results from this analysis showed countries with potential to be both peak and off-peak customers for excess power from Rwanda up to 2021. This therefore was one of the key scenarios considered within the plan – power trade as a strategy to increase company earnings.
- In line with the Paris Agreement and the 7th Sustainable Development Goal set by the United Nations (i.e. affordable and clean energy), policies existing within the Rwanda energy sector target increased contribution of renewable energy to the national electricity production. A policy target of 60% by and after 2030[13] was set to ensure compliance with global trends towards decarbonization of the energy sector. This was therefore an important factor to consider during scenario development. Within all developed scenarios, compliance with this ambitious target was monitored throughout the planning horizon.

[12] The full scope of this report includes power system analysis (static and dynamic), load flow calculations, optimal load flow, short circuit current calculations, & transient and small-signal stability simulations.
[13] Energy Sector Strategic Plan (ESSP)

- Rwanda's national power system is still small. Despite its high growth rate relative to developed countries, annual addition of the generating capacity required to expand the system is still very small. This reduces the ability of the electricity sector to benefit from economies of scale through construction of new large generating units.
- High specific investments in the construction of small power plants will inevitably lead to high electricity generation costs. The cost of electricity production by means of solar PV technologies has declined significantly in recent years and this trend is set to continue thus it is this potential option to consider. Solar electricity generation using PV is becoming cost-competitive against fossil fuels even in large interconnected systems in developed countries. Under extremely expensive electricity production conditions in Rwanda (due to its geopolitical situation), solar production may become even more competitive and may contribute to lower electricity prices.
- In Rwanda, at present, and due to the large share of domestic sector in total electricity demand, the daily peak load occurs in the evening. These hours have the greatest impact on the reliability of electricity generation and on the needs of generating capacity expansion in the system. Solar generation is not available during evening hours, when generating capacity is most required. In this case, the possibility of integrating energy storage facilities to increase generating capacity in the evening while utilizing solar energy stored during the day was examined.

6. Least Cost Generation Expansion Planning Methodology:

The key issues to address during the development of a least-cost generation expansion plan include how much new generation capacity is required, the optimal time to add new generation capacity and which supply technology should be added, given certain policy requirements or given alternative energy targets. A long-term generation expansion plan was made using the Model for Energy System Supply Alternatives and their General Environmental Impacts (MESSAGE).

MESSAGE combines different supply technologies through the construction of energy chains. The entire process of energy flows is therefore mapped out from resource extraction, conversion (***supply***) to transmission and distribution of energy services (***demand***).

The underlying principle of the model is the optimization of an objective function (in our case least-cost expansion) under defined constraints.

The major equations used to calculate the least-cost capacity addition road map within MESSAGE include:

Objective Function: **minimize cost of production while adding generation capacity**, i.e.

$$n = 1, 2, \dots, n \sum (C1X1 + C2X2 + \cdots + CnXn)$$

Where: **C = total cost**, **X = supply alternative annual added capacity**. This objective function is subject to the following main equations:

1. *Demand Equation*: Supply ≥ Demand, i.e.

   ∑ Supply ≥ ∑ Demand at all points in time.

2. *Balance Equation:* All supply options ≥ Supply from (previous) demand equation. The sum of all supply sources at each node of the system network must balance, i.e.

   ∑ Production - ∑ Consumption ≥ 0 at all levels of energy supply in the network and must meet demand at all moments in time based on available supply (variable or otherwise) and demand.

3. *Resource Equation*: The amount of exhaustible resource used to build capacity must be less than the amount of existing reserves input within the model.

4. *Capacity (& Production) Equation*: Supply Option ≤ Capacity factor (CF) X installed capacity of plant. For additional capacity installation: Supply Option ≤ CF X (Historical Capacity + New Capacity). New capacity is therefore added in a least-cost way.

5. *User defined equations and/or constraints*: e.g. CO_2 emission caps, reserve margin, import cap, RES constraint in annual production, et.c. Within the Rwandan context, some of the user-defined equations and constraints include: 15% reserve margin, maximum installed capacity of existing power plants, rehabilitation equations, et.c.

Rwanda experiences a bimodal pattern of rainfall, which is driven primarily by the progression of the Inter-Tropical Convergence Zone (ITCZ). The ITCZ follows the annual progression of the sun as it goes to the Northern Summer when the sun crosses the equator around March 21, and the Southern Summer around September 23 each year. The two rainy seasons are generally distinguishable, one (wetter) around March – May and the other around October – December. Rainfall characteristics for Rwanda exhibit large temporal and spatial variation due to varied landscape and large water bodies near the country. The highest rainfall is observed in the northern and western parts of the country, resulting in rich hydrological resources within those regions of the country. These seasonal rainfall patterns are the main driver behind the seasonal nature of production of hydropower plants which make up close to 50% of the current electricity supply of the country. This contributes to the increased complexity of modelling the Rwandan power supply system.

MESSAGE has the unique ability of modelling seasonal (renewable) supply alternatives through the use of seasonal supply divisions[14], which suits the hydro dominant supply existing within Rwanda[15], as shown in *figure 5*.

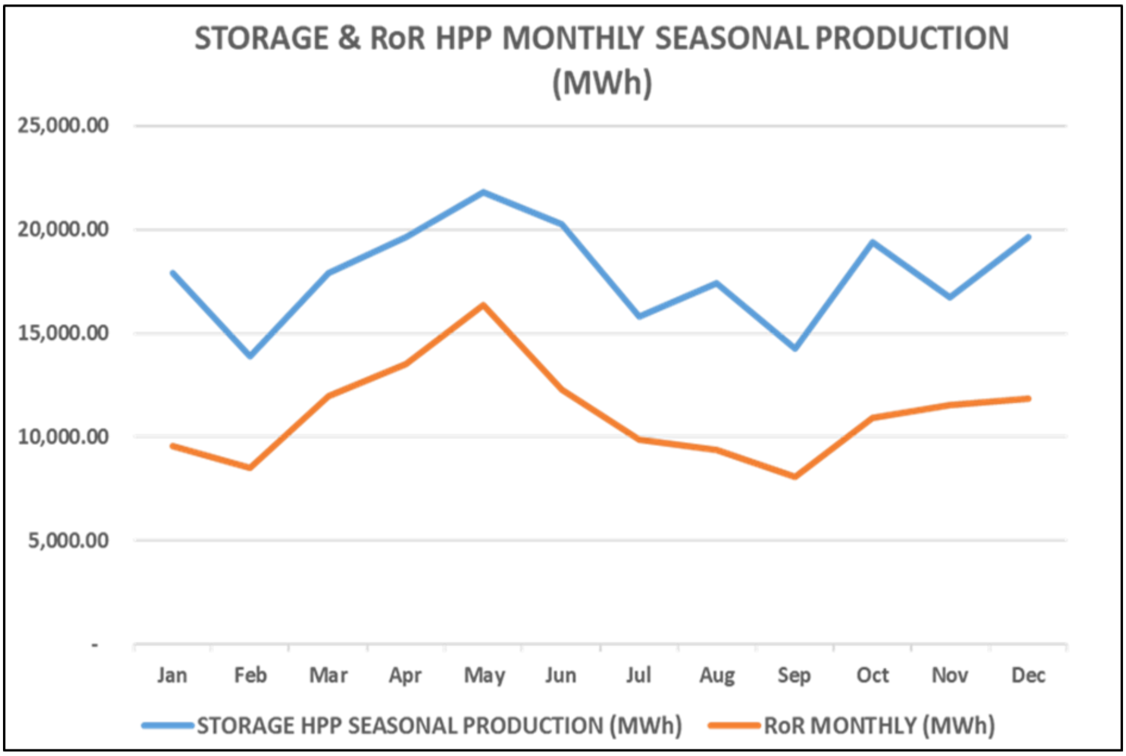

Figure 5: Hydro Power Plant Seasonal Variation

Hourly availability and production profiles of hydro and solar power plants were obtained, consolidated and the resulting operation regimes were fed into individual power plants such that their seasonal variation was captured in the most accurate way possible. The results were

[14] This is done through the use of load curves, i.e. hourly output per power plant relative to installed capacity for (variable) renewable power plants.
[15] See total installed capacity vs firm capacity difference in table

therefore not only based on plant design specifications but also on the current (hourly) seasonal situation experienced in Rwanda.

6.1. Model Inputs:

Data requirements for a least-cost expansion supply study requires a broad data set with as much information as possible to provide a most accurate depiction of the existing system. This data set must consist of all energy forms used in the country and all energy conversion processes (technologies).

6.1.1. Data determining the structure of the energy system

- **Resources**

These are exhaustible materials that are readily available for energy supply to the country through extraction, imports or any other identified means. Examples include oil, gas, peat deposits, etc. Information on available quantities all of resources and the costs associated with the exploitation of these resources (extraction and/or import costs) are the main inputs.

- **Sources of Energy**

Non-exhaustible/renewable resources such as solar, hydro, biomass, geothermal, etc are modelled differently for the majority of energy models. In terms of available quantities, the data requirements for renewable energy sources include average annual resource availability measured in standard units as well as seasonal changes in energy quantity available throughout the year. This assists in capturing the intermittency of the energy output from these sources and accurate modelling of the renewable portion of the energy system supply.

- **Existing energy conversion technologies – Techno-economic Data**

Technical characteristics include:

i. **Inputs** (e.g. natural gas, nuclear fuel, electricity).
ii. **Outputs** (e.g. electricity, heat, etc.)
iii. **Conversion efficiency characteristics** (e.g. heat rate, efficiency, losses, etc.)
iv. **Conversion capacity parameters** (i.e. installed capacity).
v. **Any other technical aspects** and/or assumptions as deemed relevant by the modeller.[16]

Economic characteristics include:

i. **Investment costs** – for existing technologies (i.e. technologies already in operation at the beginning of the planning horizon) investment costs are not important as equipment is already in place. However, if an existing technology is considered for future expansion/rehabilitation, appropriate investment costs must be provided (as well as forecasted operational costs reductions from rehabilitation of existing technology).

[16] e.g. forced outage rates, load curves for seasonal output, maintenance periods, refuelling periods, lifetime, degradation of technical characteristics during lifetime, rehabilitation plans, plant factor, operation time and lifetime.

ii. **Fixed costs**[17] – costs related to installed capacity (these costs exists even when technology is not producing/generating its output).

iii. **Variable costs** – costs related to a technology output (these costs exists when technology is producing/generating its output).

Environmental impacts can also be modelled within MESSAGE, along with any policy-relevant constraints on emissions, where relevant. Input data information can include emission quantities due to land use, water use, air pollutants such as SOx, NOx emissions from particular technologies, etc.

6.1.2. Data describing energy system development options

- **Demand analysis and projections**

Demand in MESSAGE is provided exogenously as an annual value for all years/periods during the planning horizon.

- **Candidate/expansion/future energy conversion technologies - technical, economic and environmental data**

The data required for candidate future technologies is equivalent to those for the existing ones. Representation of planned power plants and/or future expansion technologies is modelled within MESSAGE. Additional required data for non-existing but planned technologies can include the earliest year from when this technology is envisaged to be available, limits (upper and lower bounds) on installed capacity, as well as construction time.

New alternative supply technologies were also considered and added to the model. These include:

i. Solar PV (grid-connected utility-storage[18], rooftop PV systems).
ii. Hydro Pumped Storage.
iii. Biomass Generation.
iv. Battery Storage Systems.
v. Natural Gas Fired PPs[19].
vi. Methane Power Plants Capacity Addition[20].
vii. Peat Power Plant Capacity Addition[21].

6.1.3. Other user-specified data

Anything that is relevant to the objective of the supply alternative study. For the Rwandan context, these include additional equations such as import/export, policy targets for renewable energy penetration into the supply mix, base year, planning horizon, time resolution (e.g.

[17] This was used to model the take-or-pay contracts PPA structure that exists within the Rwandan context.
[18] Use of identified high-yield solar zones in Rwanda from the International Renewable Energy Agency (IRENA). High-yield solar zones were best determined considering several factors, e.g. distance to transmission line/substations/load centres/roads, solar irradiation, population destiny, etc.
[19] Plans to construct a pipeline to import natural gas from Tanzania to Rwanda are underway. Therefore potential use and construction of natural gas-fired power plants as a supply alternative was considered.
[20] Exploitation of existing methane reserves in the country.
[21] Exploitation of existing peat within the country.

annual analysis, five-year steps), currency, discount rate, reference year for costs, and other data (e.g. energy supply/take-or-pay contracts, etc.)

6.2. Options for data presentation in MESSAGE:

For even more increased accuracy within MESSAGE, options are provided for data presentation. These include:

1. **Constant ©:** a constant value that is assumed to remain constant throughout the planning horizon.
2. **Time series (ts)**: a value set for a certain number of years within the planning horizon.
3. **Constant growth (cg)**: one growth rate uniformly applied throughout the entire planning horizon.
4. **Period growth (pg):** a set of growth rates for different time periods within the study and over the entire planning horizon.

This is valid for all data used in MESSAGE and is advantageous due to the ability to model all inputs such as costs, demand, and plenty of other technical information as envisioned to change over the entire planning horizon.

6.3. Developed Generation Expansion Scenarios

Environmental targets were not explicitly modelled within the generation expansion methodology. Carbon emissions from the power generation sector were analysed from 2013 (the EDPRS II base year). A downward trend was observed (see figure 6) showing compliance with the emission targets allocated to the energy sector within the ESSP for 2018 and 2025 in figure 7. These targets were therefore not input within the software, due to the already surpassed targets for carbon intensity reduction within the energy sector.

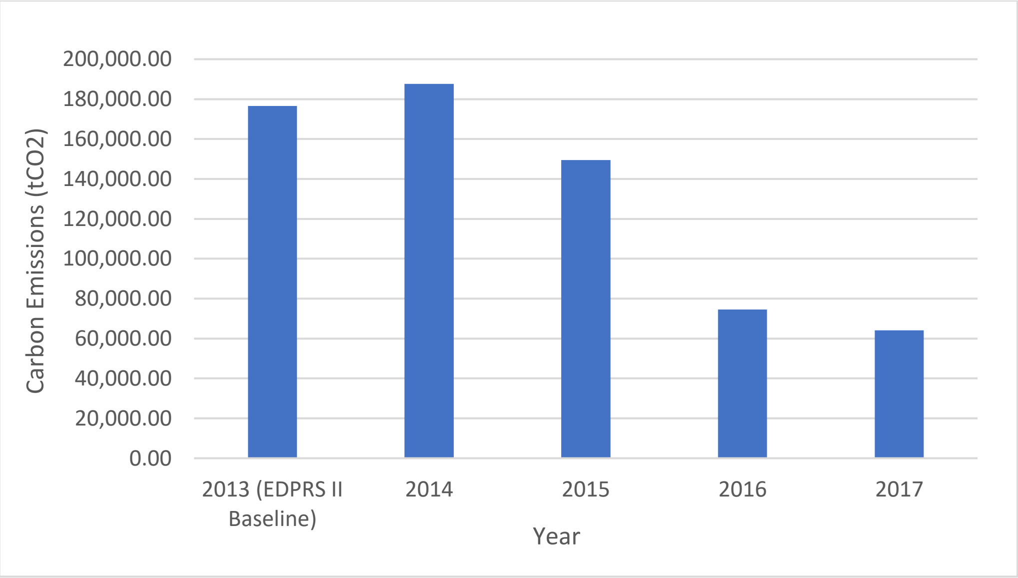

Figure 6: Carbon Emissions from Power Generation

Table 9 Carbon intensity targets[33]

Year	Carbon intensity Reduction Target	Value (tons of CO2/MWh)
Baseline	-	0.504
2018	10%	0.454
2025	25%	0.378

Figure 7: Energy Sector Carbon intensity reduction targets for the Energy Sector

As per the criteria used to develop generation expansion scenarios, **two** scenarios capture relevant least-cost options for expansion of Rwanda's installed capacity, without being repetitive or producing unrealistic results. Using forecasted annual demand growth rate for the country as well as existing and planned generation plant, techno-economic characteristics, the following expansion scenarios were created and modelled:

1. Natural Resource Exploitation (**2026 – 2040**), with **imports & exports up to 2025**.
2. Natural Resource Exploitation (**2026 – 2040**), with **only domestic production**.

6.3.1. **SCENARIO 1**: Natural Resource Exploitation (2026 – 2040), with imports & exports up to 2025.

Under this scenario, all firmly committed power plants (PPs) and small hydro power plants (HPPs) that are being commissioned in 2019/2020 are fixed within the model. Beyond 2025, least-cost capacity addition of pipeline and alternative supply technologies are considered, with power trade (i.e. import and export[22]) up to 2025[23].

6.3.2. **SCENARIO 2**: Natural Resource Exploitation (2026 – 2040), with only domestic production.

Under this scenario, all firmly committed PPs and small HPPs that are being commissioned in 2019/2020 are fixed within the model. Beyond 2025, least-cost capacity addition of pipeline and alternative supply technologies are considered, but without possibility of power trade..

[22] Import cost = 8 c/kWh, export cost = 12 c/kWh.
[23] The underlying assumption here is that given different large pipeline projects being realized in the neighbouring countries in the region, exports of power from Rwanda to her neighbours will cease beyond 2025.

7. Results Obtained

7.1. SCENARIO 1

2019 – 2025

Figure 8 shows the total installed capacity over the next 6 years. Committed plants are added onto the system in line with table 4, with imports and exports up to 2025.

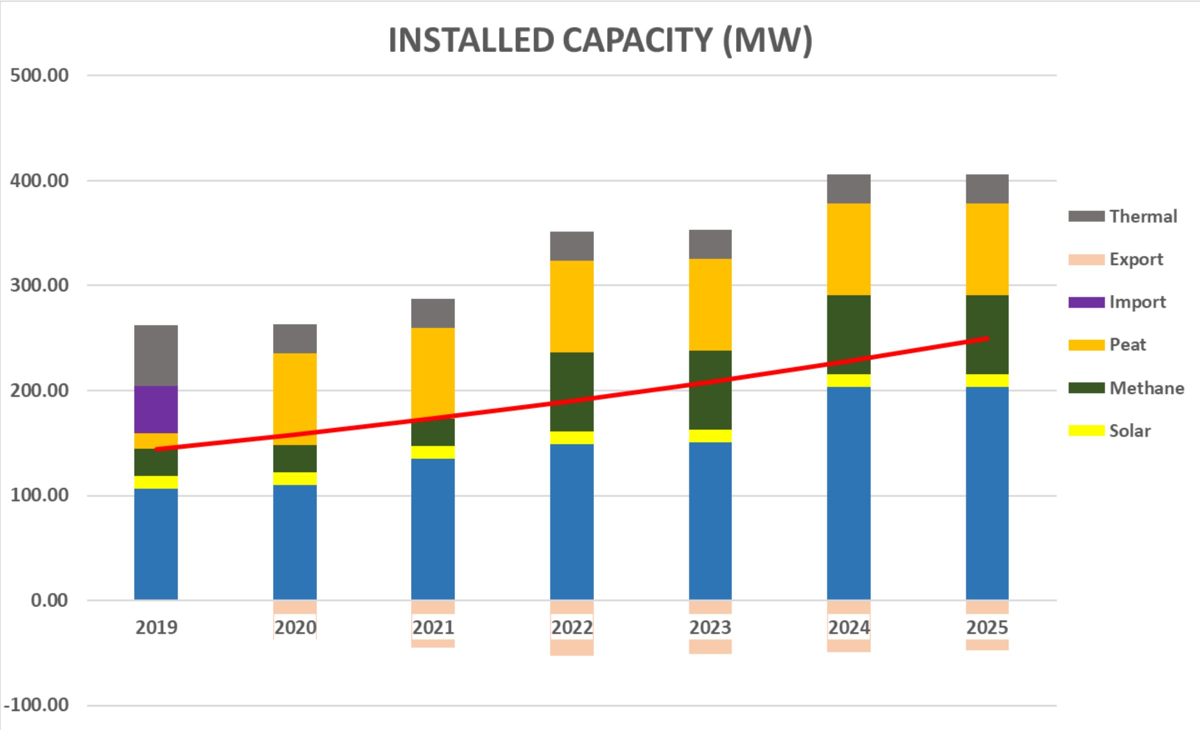

Figure 8: Installed Capacity (2019 - 2025)

Power supply from imports is recommended for 2019, as it is the cheaper option to thermal power dispatch in this year. No imports beyond this year, as there is more than enough domestic capacity to satisfy the existing national demand. Total installed capacity of thermal (diesel) powered plants remains at 27.80 MW[24] throughout the planning horizon. From 2020 – 2025, peak exports of average 47.10 MW is possible. *Table 6* shows the total installed capacity, import and export balance during this power trade period.

Year	2019	2020	2021	2022	2023	2024	2025
Hydro	106.55	110.33	134.95	148.91	150.55	203.41	203.41
Solar	11.95	11.95	11.95	11.95	11.95	11.95	11.95
Thermal	57.8	27.8	27.8	27.8	27.8	27.8	27.8
Methane	25.90	25.90	25.90	75.80	75.80	75.80	75.80
Peat	15.00	86.90	86.90	86.90	86.90	86.90	86.90
Import	44.79	0.0	0.00	0.00	0.00	0.00	0.00
Export	0	-37.17	-44.76	-52.68	-50.95	-49.5	-47.55

Table 6: Total Installed Capacity (MW) plus Imports and Exports [2019 – 2025]

[24] Jabana I and II diesel-power plants.

2026 – 2040

Figure 9 shows the evolution of total installed capacity of generation supply technologies on the Rwandan grid.

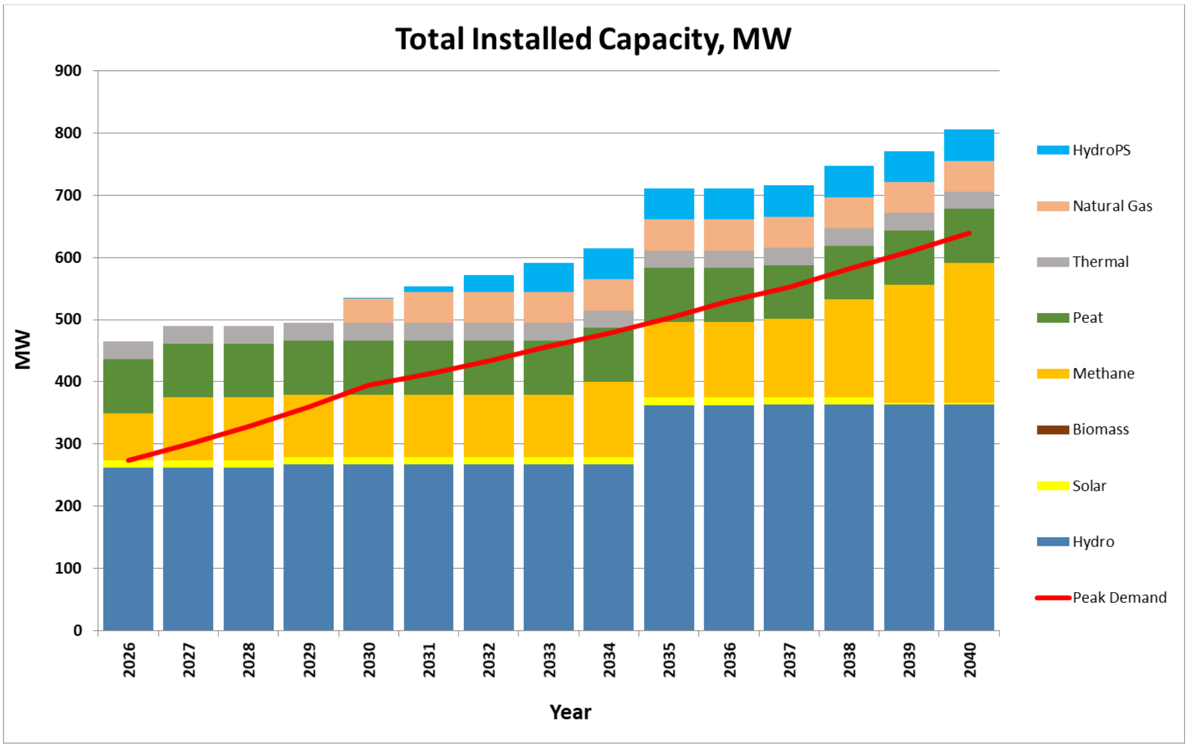

Figure 9: Total Installed Capacity (MW) 2026 - 2040

Symbion II is installed in 2027. In addition, from 2030 - 2040, two new generation supply alternatives emerge – natural gas and hydro pumped storage. These two technologies have a total installed capacity of 50 MW by 2040. Increased methane resource exploitation for electricity production is recommended from 2034 until the end of the planning horizon. Annual addition of installed capacity per technology is shown in *Table 7*.

Table 7: Annual Added Capacity per Technology Type

YEAR	POWER PLANT (MW)	TECHNOLOGY	CAPACITY ADDED (MW)
2026	Rusizi III	Hydro	48.33
2027	Symbion II	Methane	25
2028	-	-	0
2029	Nyundo HPP (3.9) Bihongore (5.35) Kore (2.40) Rucanzogera (1.45)	Hydro	13.9
2030	NG PP (39.53) Hydro PS PP (0.24)	Natural Gas Hydro Pumped Storage	39.8
2031	NG PP (10.47) Hydro PS (8.88)	Natural Gas Hydro Pumped Storage	19.4
2032	Hydro PS (18.56)	Hydro Pumped Storage	18.56
2033	Hydro PS (19.42)	Hydro Pumped Storage	19.42
2034	Methane PP (20.67) Hydro PS (2.89)	Methane Hydro Pumped Storage	23.6
2035	Rusizi IV (95.9)	Hydro	95.9
2036	-	-	-
2037	Methane (4.7)	Methane	4.7
2038	Methane PP (31.30)	Methane	31.30
2039	Methane PP (40.6)	Methane	40.6
2040	Methane (34.5)	Methane	34.5

Electricity Production & Renewable Energy Share (RES) in Total Power Production:

Figure 10 and table 8 provide a 5-year time step of the annual production profiles of each technology type during this planning horizon.

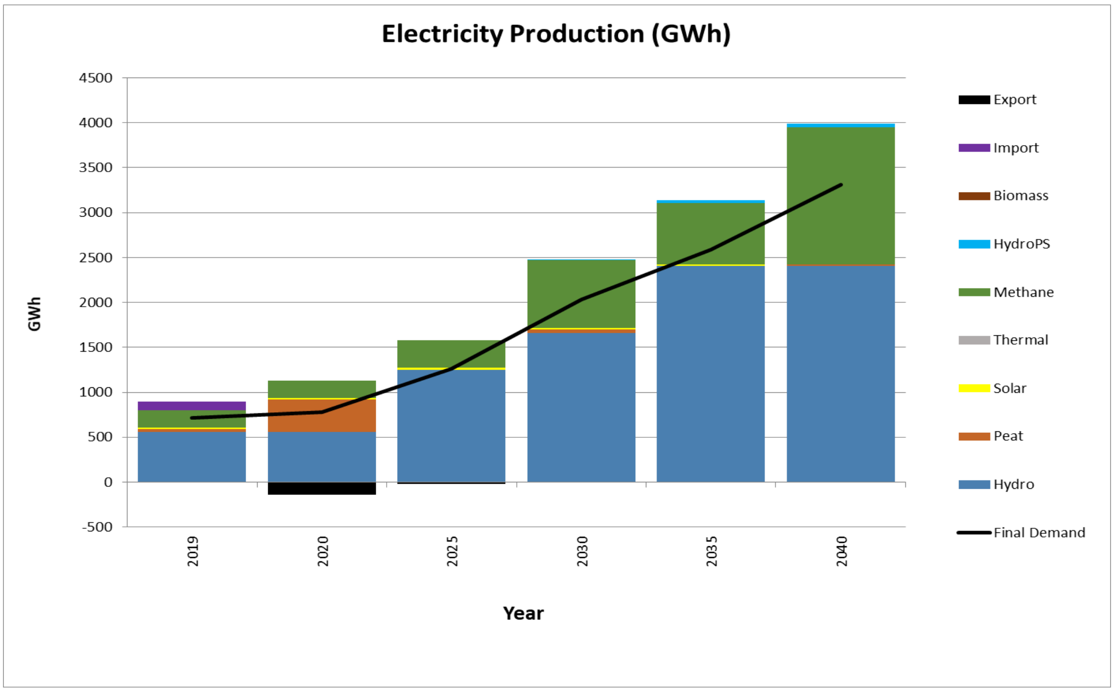

Figure 10: Electricity Production Regime

Table 8: Production per Technology Type

Year	2019	2020	2025	2030	2035	2040
Hydro	557.70	559.01	1251.86	1662.10	2402.83	2409.92
Solar	17.35	17.45	19.29	19.29	19.29	6.71
Methane	192.85	192.85	307.64	749.81	681.50	1521.22
Peat	32.78	360.67	0.00	36.85	0.00	9.59
Thermal	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00
HydroPS	0.00	0.00	0.00	0.02	33.68	42.94
Import	98.43	0.00	0.00	0.00	0.00	0.00
Export	0.00	-140.29	-19.75	0.00	0.00	0.00

It is clear that hydro dominance persists throughout the planning horizon. The significance of methane to production is also observed throughout the planning horizon, followed by peat power. In addition, thermal requirements are absent within this particular scenario even within the immediate term. this is due to the least-cost selection of supply from imports within this time period. Production from hydro pumped storage begins and starts to contribute in the longer term, as installed capacity increases.

Figure 11 shows the renewable energy share (RES) in power production throughout the planning horizon. The ESPP targets[25] set were met during this time horizon.

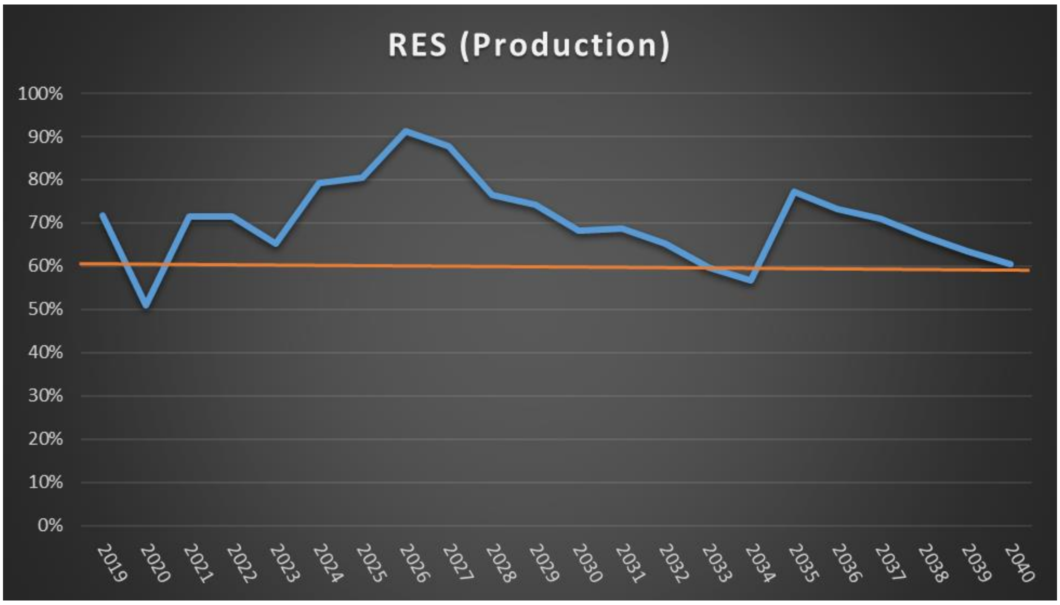

Figure 11: RES in Power Production (%)

7.2. SCENARIO 2

Under this scenario, all firmly committed PPs and small HPPs that are being commissioned in 2019/2020 are fixed within the model. Beyond 2025, least-cost capacity addition of pipeline and alternative supply technologies are considered, but without possibility of power trade.

The main difference between this scenario and the first lies in **the potential for power trade in the short term**. ***Beyond this period, the results in terms of installed capacity, production and their associated costs are the same as scenario 1***.

Electricity Production & Renewable Energy Share (RES) in Total Power Production:

Figure 12 and *table 9* provide a 5-year time step of the annual production profiles of each technology type during this planning horizon.

[25] 60% RES share in power production by and beyond 2030.

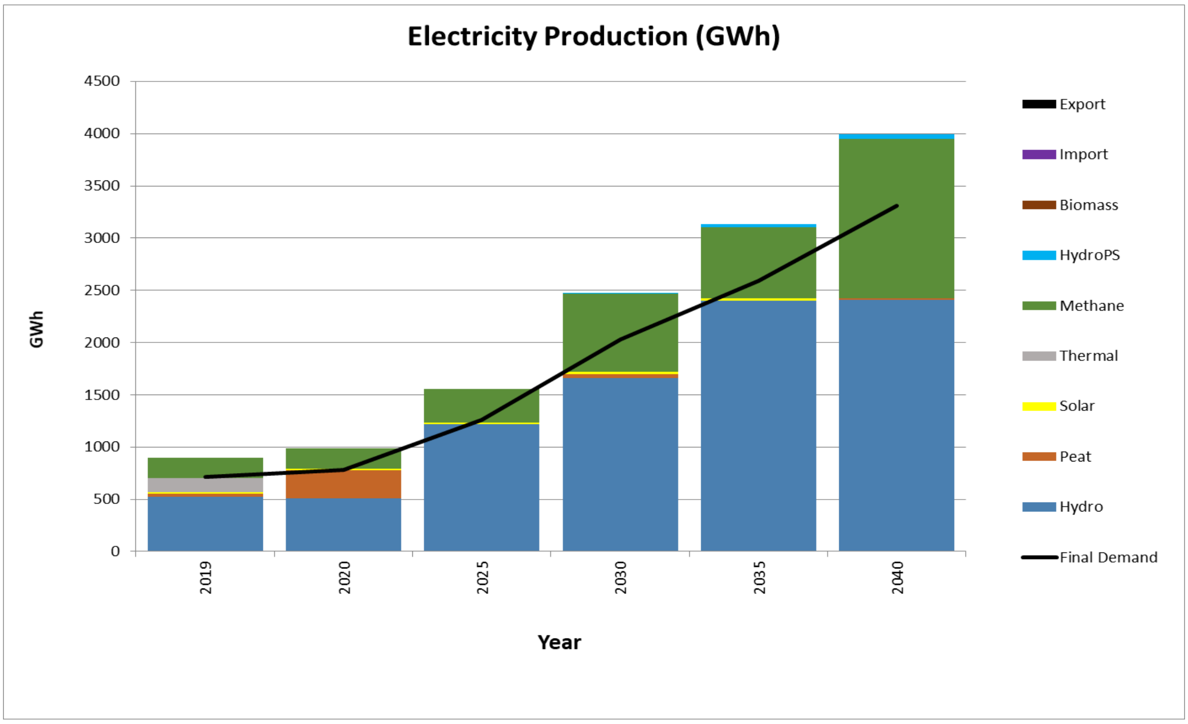

Figure 12: Electricity Production Regime

Table 9: Production per Technology Type

Year	2019	2020	2025	2030	2035	2040
Hydro	520.84	505.09	1218.03	1662.09	2402.79	2409.98
Solar	17.35	17.45	19.29	19.29	19.29	6.71
Methane	192.85	192.85	321.11	749.81	681.54	1521.19
Peat	32.78	269.96	0.00	36.84	0.00	9.55
Thermal	135.30	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00
HydroPS	0.00	0.00	0.00	0.02	33.68	42.94
Import	0.00	0.00	0.00	0.00	0.00	0.00
Export	0.00	0.00	0.00	0.00	0.00	0.00

Within the immediate term, i.e. 2019, thermal requirements are still quite high to satisfy demand. Lack of the cheaper import option therefore results in higher system costs in the immediate term. In addition, absent export opportunities lead to slightly lower production figures from these technologies – only domestic demand is being met.

Figure 13 shows the renewable energy share (RES) in power production throughout the planning horizon. The ESPP targets[26] set were met during this time horizon.

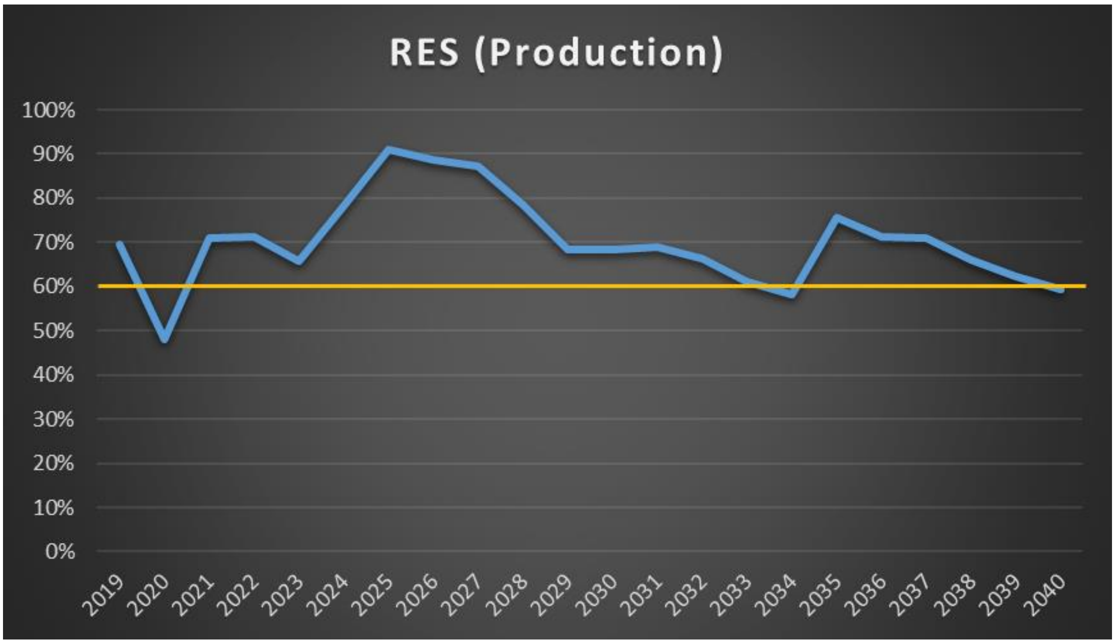

Figure 13: RES in Power Production (%)

Production comparisons between both scenarios show increased peat production during the power trade period. This signifies the production of power of peat for export purposes to increase utility earnings, which is not a possibility for scenario 2.

On the other hand, looking at renewable energy shares during the power trade period shows a difference in RES shares in electricity production (see *table 10*). 2019 shows a decrease in RES compared to scenario 1 due to use of (non-renewable) diesel compared to imports to satisfy demand, while from 2020 – 2025, export power is coming from peat and methane resources that are available and can therefore satisfy export requirements.

Table 10: RES Comparison (**Scenario 1** vs **Scenario 2**)

Year	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
RES (Production) scenario 2	66%	59%	82%	81%	73%	86%	83%
RES (Production) scenario 1	70%	46%	68%	65%	60%	79%	76%
RES (Production) scenario 2 - scenario 1	-4%	12%	14%	16%	12%	7%	8%

[26] 60% RES share in power production by and beyond 2030.

7.3. Scenario Comparison

7.3.1. Cost Comparison

Figures 14 and *15* illustrates the cost differences between scenarios 1 and 2.

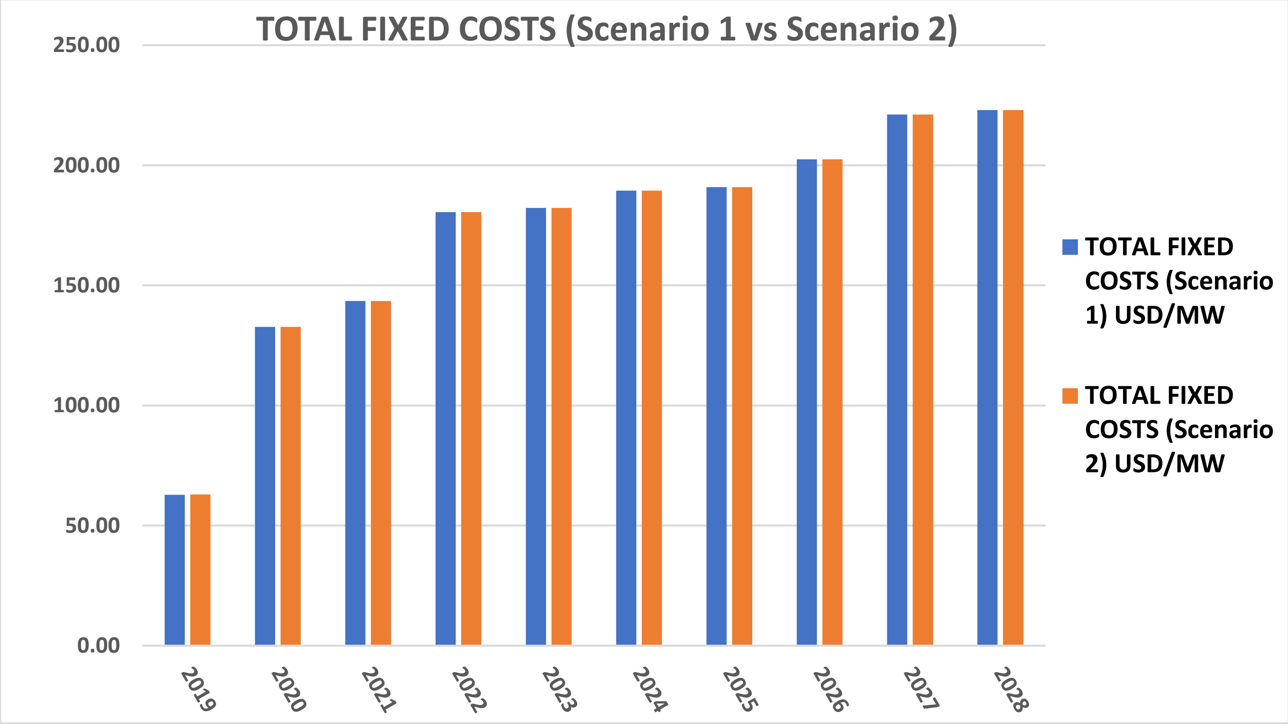

Figure 14: Fixed Cost Comparison (Scenario 1 vs Scenario 2)

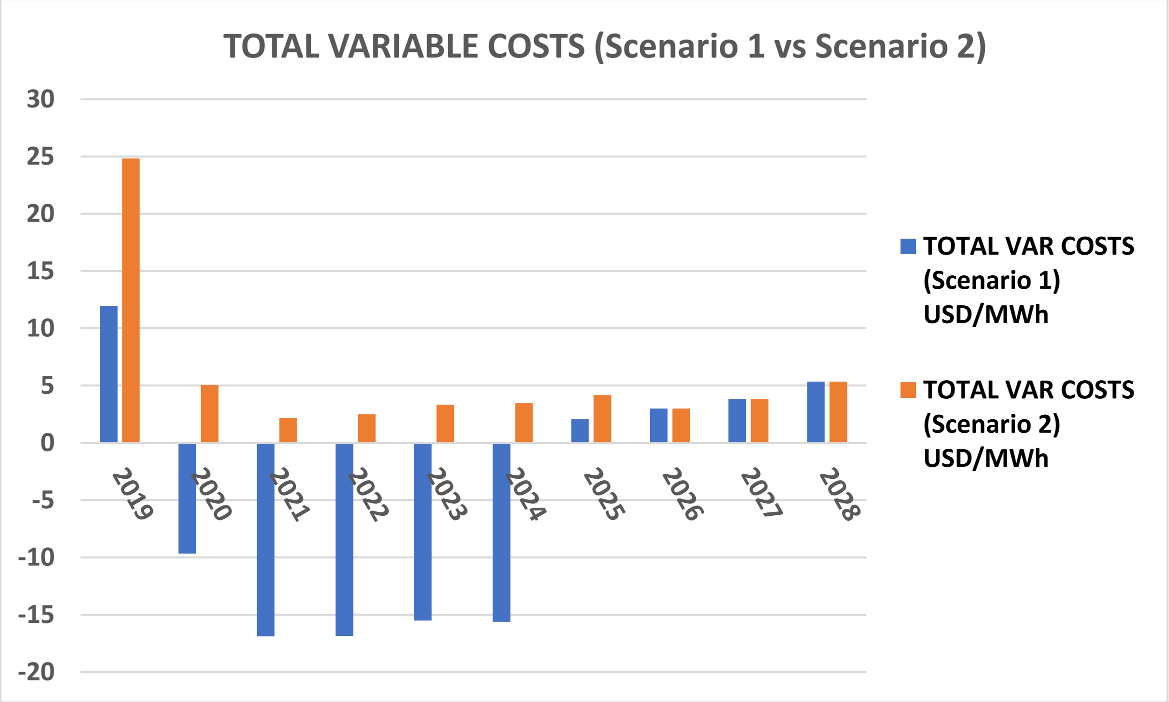

Figure 15: Variable Cost Comparison (Scenario 1 vs Scenario 2)

The cost benefits gained from scenario 1 stem from **power trade possibilities in the short term (2019 – 2025)**. As seen in *table 11*, importing power in the immediate term instead of using thermal resources will result in immediate savings of 19.8 MUSD by the end of 2019. Additionally, exports will also result in additional income, whose maximum annual value is forecasted to be 1.86 MUSD by 2025 (at an assumed tariff of 12 c/kWh). Total potential savings will be 28.6MUSD by 2025 under this power trade scenario.

SCENARIO 2 - SCENARIO 1	2019	2020	2021	2022	2023	2024	2025	2026	2027
TOTAL COST DIFFERENCE	**19.85**	1.11	1.22	1.41	1.50	1.70	**1.86**	0.03	0.03
CUMULATIVE COST DIFFERENCE	19.85	20.96	22.18	23.59	25.09	26.79	28.64	28.67	28.70

Table 11: Annual and Cumulative Production Cost Differences

Further calculation of annual system costs[27] throughout the planning horizon for both scenarios shows the area of potential earnings for the utility through export to the neighbouring countries. in addition, in the period beyond 2025 where incoming projects are firmly committed, least-cost optimization leads to a significant decrease in costs incurred by the utility. This is shown in *figure 16*.

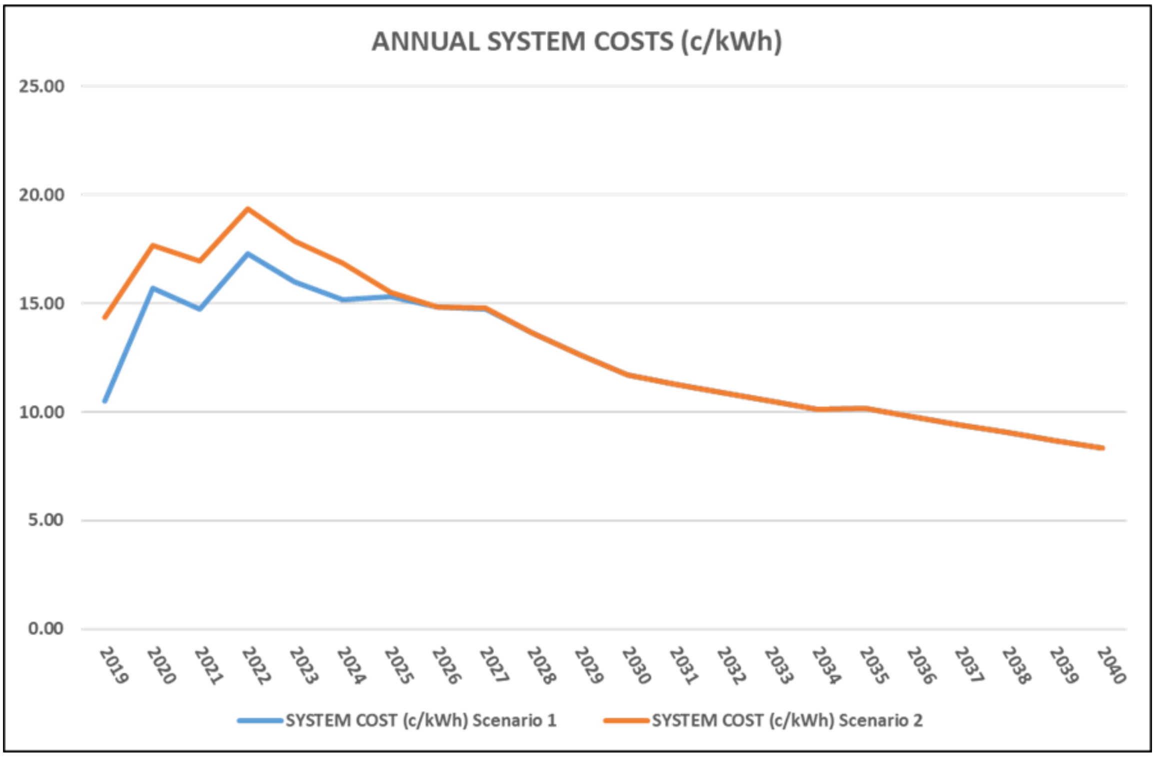

Figure 16: Annual System Costs (2019 - 2040)

[27] These costs are calculated using the formula: (annual total fixed + annual total variable costs)/final system demand. This is the bulk of the cost incurred in terms of capacity payments and overall O&M costs from the utility perspective.

8. Conclusion & Recommendations

8.1. Conclusions:

i. The least-cost development path appears to be **scenario 1**. This is due to room for power trade (imports and exports) within the short term (2019 – 2025).

ii. Renewable Energy Share (RES) target compliance with the ESSP targets throughout the planning horizon under both scenarios.

8.2. Recommendations:

i. Least-cost capacity addition of hydro pumped storage progressively from 2030 – 2034 to attain a maximum installed capacity of 50 MW.
ii. Least-cost capacity addition of hydro pumped storage would be progressively added from 2030 – 2034 to attain a maximum installed capacity of 50 MW. A pumped storage site identification and feasibility study is recommended to analyse the possibility of incorporating this supply technology in Rwanda in the longer term.
iii. Least-cost capacity addition of natural gas-fired power plants as a power supply alternative using natural gas imports from Tanzania from 2030 – 2031 to attain a maximum installed capacity of 50 MW.

iv. Import during the immediate term (2019) instead of using diesel production could result in substantial savings for the company, and therefore should be considered.
v. Additional investigation on off-peak export to neighbouring countries (average off-peak export available = 70.71 MW). Given the current expenses associated with battery storage, it is not recommended as a supply alternative.
vi. Stimulation of demand growth (particularly industrial demand to improve the country load factor) to over 10% to absorb the incoming capacity in the short term.
vii. Natural gas fired power generation was initially considered as an option. Further clarifications on the possibility, potential size and cost of this supply option are underway to prove the viability of using this as a potential supply alternative in the long run.
viii. Import during the immediate term (2019) instead of using diesel supply during peak hours could result in substantial savings for the company, and therefore should be considered.
ix. Given the current expenses associated with battery storage, it is not recommended as a supply alternative.

9. Way Forward

No	Challenge	Recommendations
1	Generation expansion to be delivered in line with demand growth	Proposed generation road map and updated LCPDP to be approved by the GoR (MININFRA/MINECOFIN)
		Demand forecasting to be updated regularly based on realistic plans and assumptions aligned to the next planning cycle.
2	Use of 3 years' (2015 – 2018) worth of hydrological and production data within the model.	Efforts will be taken to continuously update this data moving forward per LCPDP update.
3	Limited river inflow data	Further investigations on inflows concerning the generating power plants.
4	Potential impacts of climate change on the hydro dominant energy supply mix of Rwanda was not conducted.	Efforts will be made to consider the potential impact of adverse conditions of climate change based on weather forecasts on water availability and hence hydro output will be done.
5	Ascertaining the exact amount of lake methane that can be exploited for electricity production in an economical and sustainable way.	Research will be done in cooperation with Kivu Monitoring Project to ascertain the available and sustainable capacity of Methane gas.
6	Demand Growth to be increased	GOR policy decision to be taken to simulate demand growth of over 10%.
		Required infrastructure for industrial parks to be in place.
		Introduce more commercial and industrial demand and provide incentives for consumption in off-peak (introduction of reduced tariffs for consumers during off-peak periods to promote load shifting).
7	New Supply Technologies	Consultant to perform capacity study for hydro pumped storage in Rwanda to be hired, in line with the LCPDP development road map in the longer term.
		More accurate modelling of potential capacity of natural gas-fired power plants once import capacity of natural gas from Tanzania pipeline is known.
8	System Stability	Installed capacity of new power plants should not exceed a multiple of 10% of Rwanda grid capacity (peak demand) at the time of CoD, to avoid high spinning reserves and instability of the grid and cost involved in case of disturbances caused by the new plant

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