RWANDA: LEAST COST POWER DEVELOPMENT PLAN (LCPDP)

2025-2050

2024 Review

Rwanda Energy Group
REG

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 and inscribed in the initiatives of the strategic plan and consistent with the energy sector strategy.

The purpose of the plan is to have a systematic development of the Rwanda Generation Resources prioritizing the least cost options to ensure that the tariff affordability objectives are being optimized. The least cost study is segmented into two phases: *entry of committed projects* (**2025 – 2031**) and *the long-term* (**2032 - 2050**).

Rwanda currently has limited generation resources especially during the dry season when many hydro power plants face water shortage problems. During this period, peat fired power plants and import provide power for seasonal balances while diesel generation is used for emergency response, and to supply the peak demand in extreme high demands. Efforts have been conducted to ascertain the true quantity of existing resources within the country for electricity generation with solar potential conducted, as well as BESS potential and remaining methane gas resource underway. The results from the electricity generation resources study, which analysed the technical, economic and market potential of hydro, solar, biomass, wind, peat, methane and geothermal resources have been used for this update and will continue for subsequent least cost power development plan (LCPDP) updates.

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 raises the risk of higher 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 the Government should therefore use as the least-cost entry dates, technologies and capacities of committed (signed PPA's) generation plants.

The results within this report provide 12 scenarios in total based on 4 supply-side scenarios and 3 demand side scenarios for a stress-test on the power generation capacity across different electricity demand growth trajectories. The results of the simulations indicate low-cost differences among low demand growth scenarios except the power trade and interconnections. With the least cost option differing per scenario, the reference case is the least cost scenario in the low demand growth trajectory, the renewables scenario in the medium demand trajectory, and the Domestic/Security of Supply in the high growth scenario. From a medium-term planning perspective (high demand growth), whereby the energy sector 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 (universal access to modern and clean energy), it is recommended to speed up pre-implementation and project development of the following technologies to meet the anticipated demand and adequate reserves in the medium term horizon:

- Nyabarongo-2 hydro power plant.
- Rusizi-3 Regional Hydropower plant.
- 100 MW of Solar PV capacity integrated with storage (Nyabarongo2 HPP Solar PV with possibility for expansion).

- Scaling up existing methane-fire power plants by at least 25 MW
- Rukarara VI hydropower plant.
- Design and develop Rwanda solar park initially with potential for scale up to 128 MW.
- Increase emergence/standby thermal ramp up capacity to 41 MW.
- Strengthen power trade N-1 contingency with additional imports of 50 MW.
- Undertake technical feasibility studies to increase emergence/standby capacity to grow proportionately to the system growth.
  This might necessitate upgrading of Jabana1 from 7.8 MW to 30 MW is required to maintain a higher reserve margins 15%, and high grid frequency response, especially in the event of extreme seasonal weather variations (hydrological and sunshine).

Over the planning horizon, the following need to be initiated to meet demand in the long term:

- Fast-track the feasibility study for Nuclear SMR technology.
- Undertake feasibility studies for:
  - Exploratory studies for further methane-fired power plants
  - natural gas pipeline and natural gas fired power plants.
  - battery energy storages systems.
- Studies to increase further renewable energy sources:
  - Green hydrogen,
  - Solar PV + BESS,
  - Exploratory studies for geothermal.

This approach to invest in project pre-implementation and development, especially for emerging and new technologies into the Rwandan grid would provide the advantage of a least cost technology adoption and set national power supply to an affordable tariff trajectory. From a long-term perspective, further resource and technical studies into these emerging technologies (include utility scale solar PV with storage, consumer-sized battery storage services, and hydro pumped storage) should be carried out, as more technological development information comes up, and the regional landscape transforms which could enhance primary resources trading (gas and oil pipelines, railways, power trading), etc... In addition, the bottom-up approach to demand forecasting needs also continued monitoring and actualisation as the policy aspirations and the resulting social economic transformations dramatically alter the current system characteristics with more demand-side management.

Content

Figures

Tables

Equations

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 update 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 meet country's the forecasted electricity demand for while maintaining an adequate operational reserve margin[1]. 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.

Additionally, the plan aims to::

i. Maximise the integration of renewable energy into the national energy mix..
ii. Optimise . electricity supply to meet peak demand while minimizing the risk of generating excess capacity.
iii. Align with Rwanda's energy policy[2] and the energy sector strategic plan (ESSP)[3] that highlight the need for a least cost power development plan to guide power generation capacity increase and investments.

1 The NST-1 reserve margin is maintained at a 15% target

2 Rwanda Energy Policy: http://www.mininfra.gov.rw/fileadmin/user_upload/new_tender/Energy_Policy.pdf.

3 ESSP: http://mininfra.gov.rw/fileadmin/user_upload/new_tender/Energy_Sector_Strategic_Plan.pdf.

The document is structured as follows:

- **Section 2** provides an overview of Rwanda's energy sector.
- **Section 3** presents the demand forecast.
- **Sections 4 and 5** examine existing and planned generation projects.
- **Section 6** details the least-cost planning methodology, generation expansion scenarios, and the modeling software used.
- **Section 7** includes updates from December 2024.
- **Section 8** discusses the results of the least-cost modeling analysis.
- **Section 9** explores the impact of climate change on hydropower production.
- **Section 10** concludes with key findings, proposed actions, and the way forward.

.

2. Rwanda Energy Sector Overview

Rwanda is a land-locked country with a surface area of 26,338 km^2 and a growing population, standing at 13.25 million[4]. It is densely populated with 503 habitants per square kilometre[5], and a per capita GDP of 1,031 (current) USD/capita[6] in 2023. Rwanda's economy has been growing at an annual average rate of 8.3% and the Government is targeting an annual average growth rate of 9.1% over the NST2 period (2024-2029). Ensuring universal access to affordable and modern sources of energy remain the paramount target to be achieved by the energy sector.

Rwanda's energy sector consists of different players with different roles to play as specified within the Rwanda grid code. *Figure 1* below provides an overview of the energy sector operating in the country at present.

State-owned Rwanda Energy Group (REG) was incorporated in 2014 to expand, maintain and operate energy infrastructures 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.

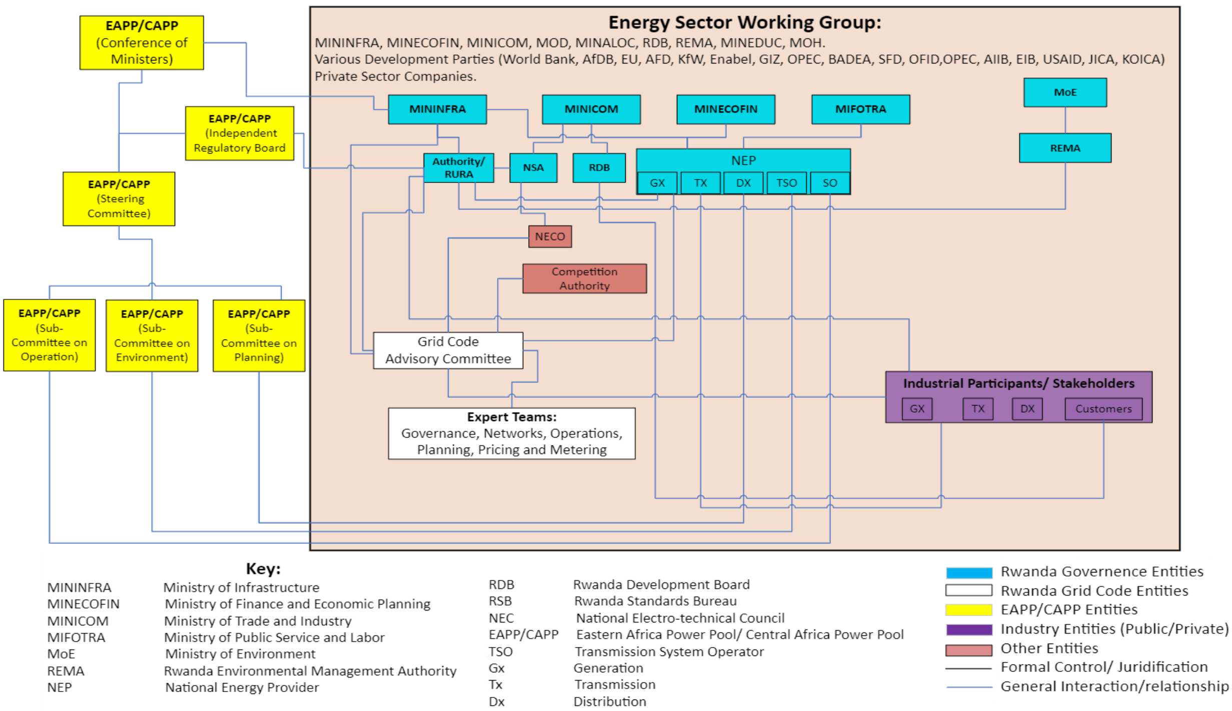


Figure 1: Rwanda's Current Energy Sector Structure

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

4 NISR 2022 Population and Housing Census.

5 NISR 2022 Population and Housing Census.

6 NISR 2023 Gross Domestic Product

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.

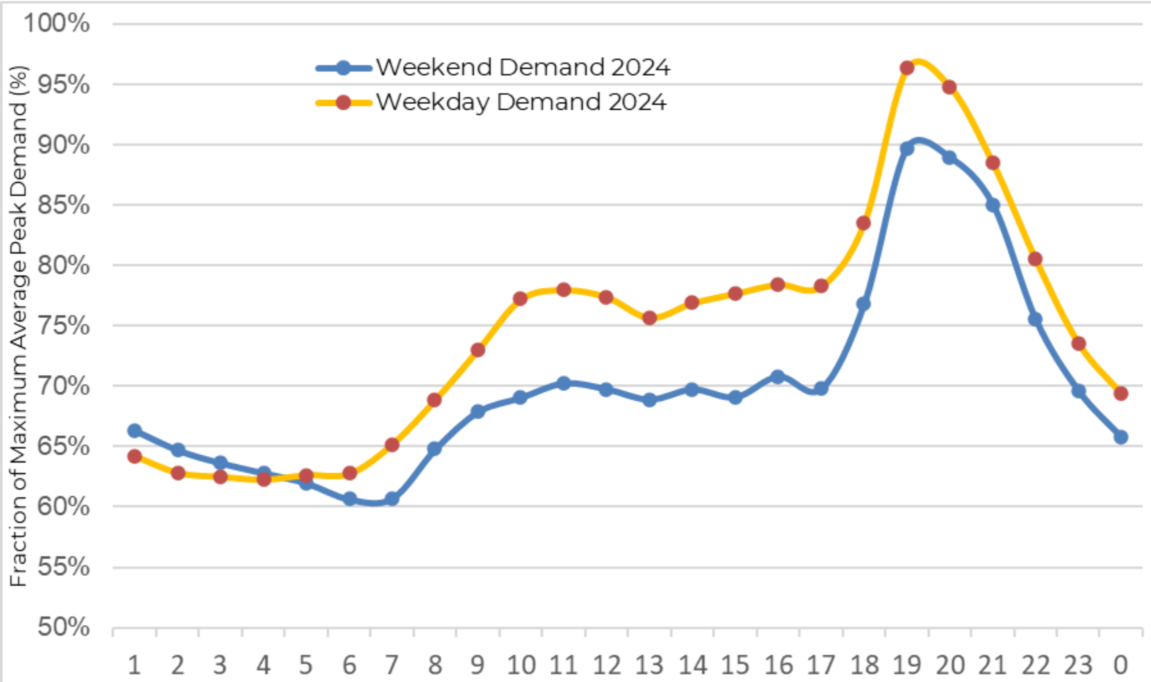


Figure 2: Weekday/Weekend Load Curve, Fraction of Maximum Weekly Demand 2024

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

Trend forecasting assumes that past electricity usage per consumer category, will continue to grow at a uniform rate. A growth rate derived from historical data (sales or peak demand data) is 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:

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

Equation 1: End-Use Demand Forecasting

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[7], 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

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

extremely data-intensive. Surveys of different types of buildings are usually needed to collect good data on energy end-uses.

In addition, zonal demand data for bulk electricity loads are compiled to constitute short to medium-term demand trajectories and used to test robustness of these demand forecasts. The following Table 1 summarises bulk electricity loads for the horizon 2025-2030.

Table 1: anticipated major loads (MW) by load category and sub-national administrative entities.

Load category	Kigali	South	North	East	West	Total by 2030
Big Industries	30.2	10.0	34.0	67.2	8.2	149.6
Commercial complexes + Big Offices +Market	29.5	1.8	4.0	1.0	0.4	36.7
Hotels & Apartments	4.8	2.4	0.1		0.8	8.1
Hospital and Clinics	2.5				0.4	2.9
Small Industries (SMEs) & Modern Markets	10.4	1.9	13.3	15.6	3.9	45.1
Real Estate Projects	11.9		0.3		2.0	14.2
Airport & Stadium Expansion	45.1	3.5	0.6	0.2	0.6	50.0
Transport	30.3				0.2	30.5
Water Treatment plants	4.2	2.0	0.7	20.7	4.7	32.3
Streetlights+ CCTV Cameras	0.6	0.5	0.7	1.5	1.7	5.0
Other loads	25.6	1.5	4.3	28.4	1.4	61.2
Total anticipated major loads by 2030	**195**	**23**	**58**	**135**	**24**	**435**

Note: An extensive zonal analysis of these bulk electricity loads is provided in the Distribution Network Development Plan

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 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 and supplemented by further historical data revealed a direct (1:1) correlation between GDP growth and growth in electricity consumption per capita in Rwanda as shown in 25-year historical data below.

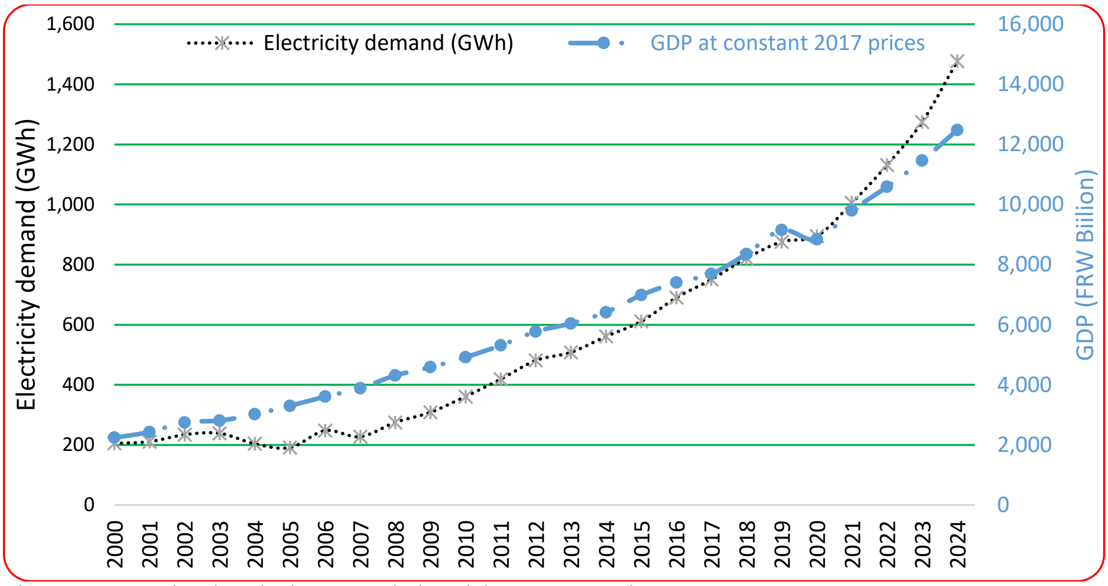


Figure 3: Rwanda Historical GDP and Electricity Consumption Data.

An additional study conducted by Israel Electric Company considered different annual growth rates of 8% (*low growth*), 10% (*base case*) and 12% (*high growth*) due to the uncertainty of forecasts. Additionally, to align with strategic National Development aspirations of Rwanda Vision 2050, 2 additional scenarios were included of 15% annual demand growth with a relaxed expansionary gradient at 12% from 2031 onwards. These electricity demand forecasts were then calculated in line with recent historical trends, using existing hourly load curves for the years 2017-2024. Peak and energy demand forecasts over the next 26 years were calculated as shown in table 2 below.

Table 2: Annual Peak Demand & Energy Demand Growth for Different Growth Rates

Year	Scenario: 8% growth		Scenario: 10% growth		Scenario: 12% growth		Scenario: 15% growth		Scenario: 15% & 12% growth	
	Peak demand in MW (8% growth)	Total Electricity Demand in TWh (8% growth)	Peak demand in MW (10% growth)	Total Electricity Demand in TWh (10% growth)	Peak demand in MW (12% growth)	Total Electricity Demand in TWh (12% growth)	Peak demand in MW (15% growth)	Total Electricity Demand in TWh (15% growth)	Peak demand in MW (15% growth till 2030) and 12% after	Total Electricity Demand in TWh (15% growth till 2030) and 12% after
2016	119	0.690	119	0.690	119	0.690	119	0.690	119	0.690
2017	134	0.750	134	0.750	134	0.750	134	0.750	134	0.750
2018	139	0.821	139	0.821	139	0.821	139	0.821	139	0.821
2019	147	0.876	147	0.876	147	0.876	147	0.876	147	0.876
2020	155	0.895	155	0.895	155	0.895	155	0.895	155	0.895
2021	171	1.005	171	1.005	171	1.005	171	1.005	171	1.005
2022	185	1.131	185	1.131	185	1.131	185	1.131	185	1.131
2023	211	1.275	211	1.275	211	1.275	211	1.275	211	1.275
2024	242	1.477	242	1.477	242	1.477	242	1.477	242	1.477
2025	262	1.595	266	1.625	271	1.654	278	1.699	278	1.699
2026	283	1.723	293	1.787	304	1.853	320	1.953	320	1.953
2027	306	1.861	322	1.966	340	2.075	368	2.246	368	2.246
2028	330	2.009	354	2.162	381	2.324	423	2.583	423	2.583
2029	356	2.170	389	2.379	427	2.603	486	2.971	486	2.971
2030	384	2.344	428	2.617	478	2.915	559	3.416	559	3.416
2031	415	2.531	471	2.878	535	3.265	643	3.929	626	3.826

Year	Scenario: 8% growth		Scenario: 10% growth		Scenario: 12% growth		Scenario: 15% growth		Scenario: 15% & 12% growth	
	Peak demand in MW (8% growth)	Total Electricity Demand in TWh (8% growth)	Peak demand in MW (10% growth)	Total Electricity Demand in TWh (10% growth)	Peak demand in MW (12% growth)	Total Electricity Demand in TWh (12% growth)	Peak demand in MW (15% growth)	Total Electricity Demand in TWh (15% growth)	Peak demand in MW (15% growth till 2030) and 12% after	Total Electricity Demand in TWh (15% growth till 2030) and 12% after
2032	448	2.734	518	3.166	599	3.657	739	4.518	701	4.286
2033	484	2.953	570	3.483	671	4.096	850	5.196	785	4.800
2034	523	3.189	627	3.831	752	4.587	978	5.975	879	5.376
2035	565	3.444	690	4.214	842	5.138	1125	6.872	984	6.021
2036	610	3.719	759	4.635	943	5.754	1294	7.902	1102	6.743
2037	659	4.017	835	5.099	1056	6.445	1488	9.088	1234	7.553
2038	712	4.338	919	5.609	1183	7.218	1711	10.451	1382	8.459
2039	769	4.685	1011	6.170	1325	8.084	1968	12.018	1548	9.474
2040	831	5.060	1112	6.787	1484	9.055	2263	13.821	1734	10.611
2041	897	5.465	1223	7.465	1662	10.141	2602	15.894	1942	11.884
2042	969	5.902	1345	8.212	1861	11.358	2992	18.279	2175	13.310
2043	1047	6.374	1480	9.033	2084	12.721	3441	21.020	2436	14.907
2044	1131	6.884	1628	9.937	2334	14.248	3957	24.173	2728	16.696
2045	1221	7.435	1791	10.930	2614	15.957	4551	27.799	3055	18.700
2046	1319	8.030	1970	12.023	2928	17.872	5234	31.969	3422	20.944
2047	1425	8.672	2167	13.226	3279	20.017	6019	36.765	3833	23.457
2048	1539	9.366	2384	14.548	3672	22.419	6922	42.279	4293	26.272
2049	1662	10.115	2622	16.003	4113	25.109	7960	48.621	4808	29.425
2050	1795	10.924	2884	17.603	4607	28.122	9154	55.914	5385	32.956

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 2016-2050. Bearing the uncertainties associated with demand forecasting and the different results presented by these studies, annual electricity demand is broken down into 5 years medium term spans revealing different growth levels ranging from the lowest: 4.97% during 1998-2003, to the highest ever of 14.45% during 2008-2013. With the overall average growth of 8.44% over the past 25 years consistent with the implementation of the current strategic plan, 9.20% demand growth during 2017-2023, a 10% annual electricity demand growth rate is used for the reference case of Rwanda's generation expansion scenario development and expansion planning with sensitivity analyses conducted on a bound between 8%, 12%, 15% annual demand growth and a combined 15% and 12% demand growth till 2030, and afterwards respectively. The results are presented in section 6.3. Figure 3 below illustrates the forecasted energy and peak demand growth.

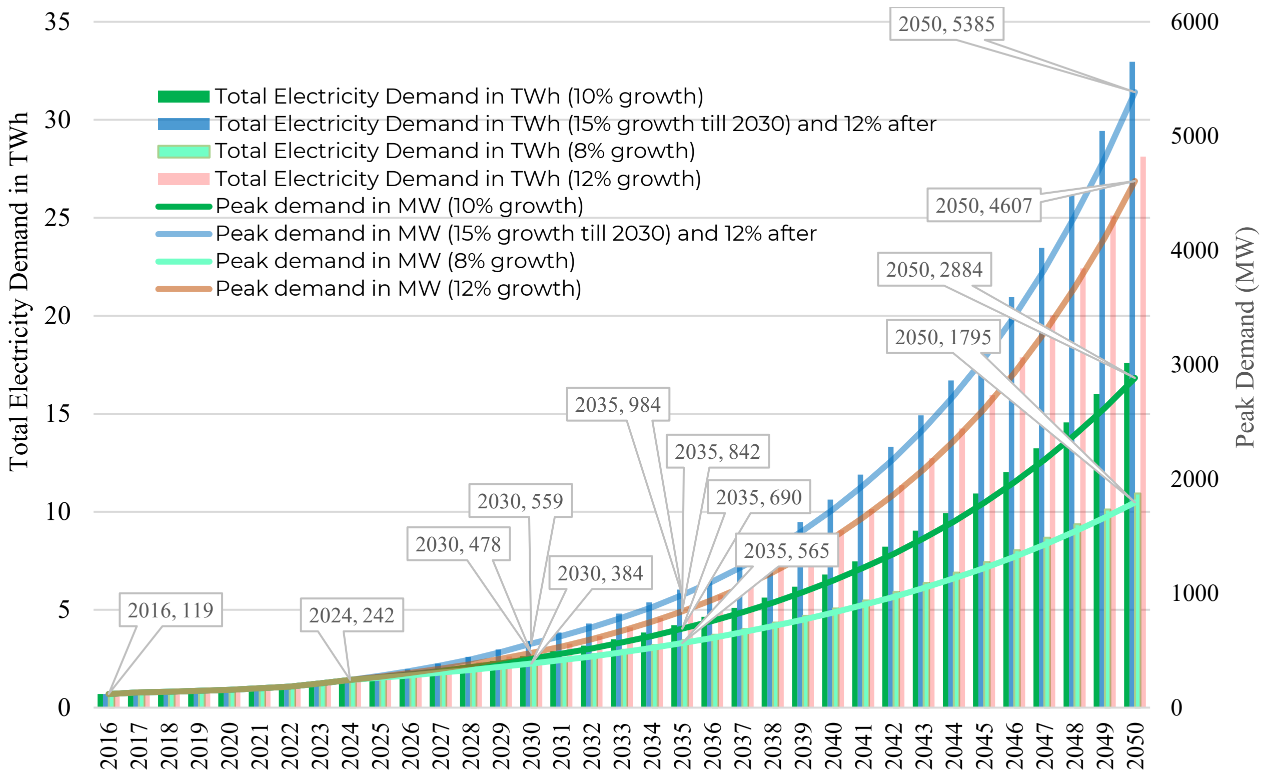


Figure 4: Forecasted Total Demand and Peak Demand

4. Existing Generation Plants

Table 3 provides a list of the existing generation plants within Rwanda, as well as their associated characteristics.

Table 3: Existing generation plants and power generation capacity

No	Plant Name	Installed Capacity (MW)	Capacity Factor (%)	Available Capacity (MW)	Owner	COD	Type of Technology
1	Ntaruka	11.25	70.00	7.9	GoR	1959	Hydro
2	Mukungwa I	12	70.00	8.4	GoR	1982	Hydro
3	Nyabarongo I	28	68.54	19.2	GoR	2014	Hydro
4	Gisenyi	1.7	65	1.1	Prime Energy Ltd	1957	Hydro
5	Gihira	1.8	70	1.3	RMT	1984	Hydro
6	Murunda	0.1	45	0.0	Repro	2010	Hydro
7	Rukarara I	9	40	3.6	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	0	0.0	Adre Hydro&Energicotel	2011	Hydro
11	Nyamyotsi II	0.1	0	0.0	Adre Hydro&Energicotel	2011	Hydro
12	Agatobwe	0.39	35	0.1	Carera-Ederer	2010	Hydro
13	Mutobo	0.2	45	0.1	Repro	2009	Hydro
14	Nkora	0.68	50	0.3	Adre Hydro&Energicotel	2011	Hydro
15	Cyimbili	0.3	50	0.2	Adre Hydro&Energicotel	2011	Hydro
16	Gaseke	0.5	90	0.5	Novel Energy	2017	Hydro
17	Mazimeru	0.5	49	0.2	Carera-Ederer	2012	Hydro
18	Janja	0.2	80	0.2	RGE Energy UK ltd	2012	Hydro
19	Gashashi	0.28	40	0.1	Prime Energy Ltd	2013	Hydro
20	Nyabahanga I	0.2	55	0.1	GoR	2012	Hydro
21	Nshili I	0.4	0	0.0	GoR	2012	Hydro
22	Rwaza Muko	2.6	60	1.6	Rwaza HydroPower Ltd	2018	Hydro
23	Musarara	0.4	49	0.2	Amahoro Energy	2013	Hydro
24	Mukungwa II	3.6	73	2.6	Prime Energy Ltd	2013	Hydro
25	Rukarara II	2.2	52.5	1.2	Prime Energy Ltd	2013	Hydro
26	Nyirabuhombohombo	0.65	35	0.2	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	Giciye III	9.8	40	3.9	RMT	2020	Hydro
30	Rukarara V Mushishito	5	60	3.0	Omni Hydro Ltd	2019	Hydro
31	Rubagabaga	0.45	61	0.3	Rubagabaga Hydropower Ltd	2019	Hydro
32	Nyirantaruko	1.84	65	1.2	SPV Nyirantaruko	2020	Hydro
33	Kigasa	0.27	37	0.1	LED Solutions & Green Energy Rwanda Ltd	2020	Hydro
34	Mukungu MHPP	0.02	60	0.0	GoR	2020	Hydro
35	Kavumu-Mwange	0.33	60	0.2	REGREPOWER	2023	Hydro
36	Ntaruka A	2.10	60	1.3	Ngali Energy	2023	Hydro
	S-total	**109.8**		**64.6**			
37	Jabana 1	7.8	95	7.4	GoR	2004	Diesel
38	Jabana 2	21	95	20.0	GoR	2009	HFO-Diesel
	S-total	**28.8**		**27.4**			
39	Gishoma	15	85	12.8	Gasmeth Energy Ltd	2016	Peat

No	Plant Name	Installed Capacity (MW)	Capacity Factor (%)	Available Capacity (MW)	Owner	COD	Type of Technology
40	Hakan	70	38	26.6	Hakan	2021	Peat
	S-total	**85**		**39.4**			
41	Kivuwatt	26.19	91.03	23.8	Contour Global	2016	Methane
42	KP1	3.6	0	0.0	GoR	2009	Methane
43	SPLK	56	90	50.4	SPLK	2023	Methane
	S-total	**85.8**		**74.2**			
44	Jali	0.25	14.00	0.0	Mainz Stadwerke/Local Agency	2007	Solar
45	GigaWatt	8.5	17.08	1.5	Gigawatt Global	2013	Solar
46	Nasho Solar	3.3	16.08	0.5	GoR	2017	Solar
	S-total	**12.05**		**2.0**			
47	Mururu 1	4.1	95	3.9	SNEL Sarl	1957	Imports
48	Mururu II	12	95	11.4	SINELAC	1957	Shared
49	Gatuna	2	95	1.9	UETCL	2016	Imports
50	Mirama	100	70.00	70.0	UETCL	2023	Imports
51	Rusumo Regional HPP	26.7	75.00	20.0	Rusumo Power Company Ltd	2023	Shared
	S-total	**144.8**		**107.2**			
	Grand Total	**466.2**		**314.8**			

The resulting energy mix is shown in *Figure 4* below. Thermal, units, especially HFO/diesel, have been contributing a considerable share to the energy mix between 2005 and 2016, but since 2023, the contribution of thermal reduced from baseload to currently emergence use and peak balancing only. For the past two years, these units, were operated during peak hours due to their high operation cost. REG continues to ensure maximum use of cheaper hydro power options, and these are supplemented by peat fired PPs and Solar PVs in pipeline especially during dry seasons where hydro power generation falls to their lowest capacity factors.

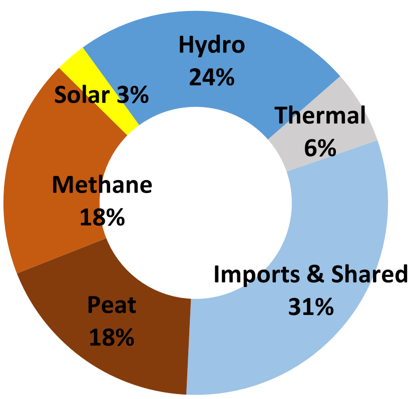


Figure 5: Share of installed capacity by energy source

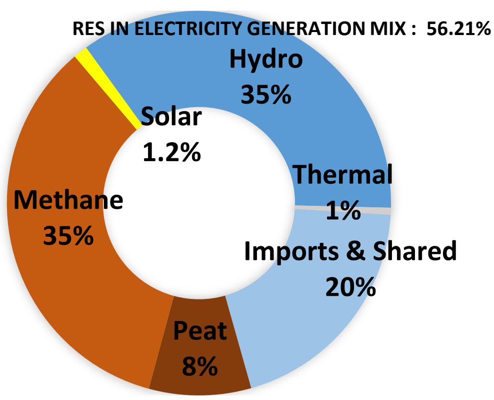


Figure 6: Current power generation mix

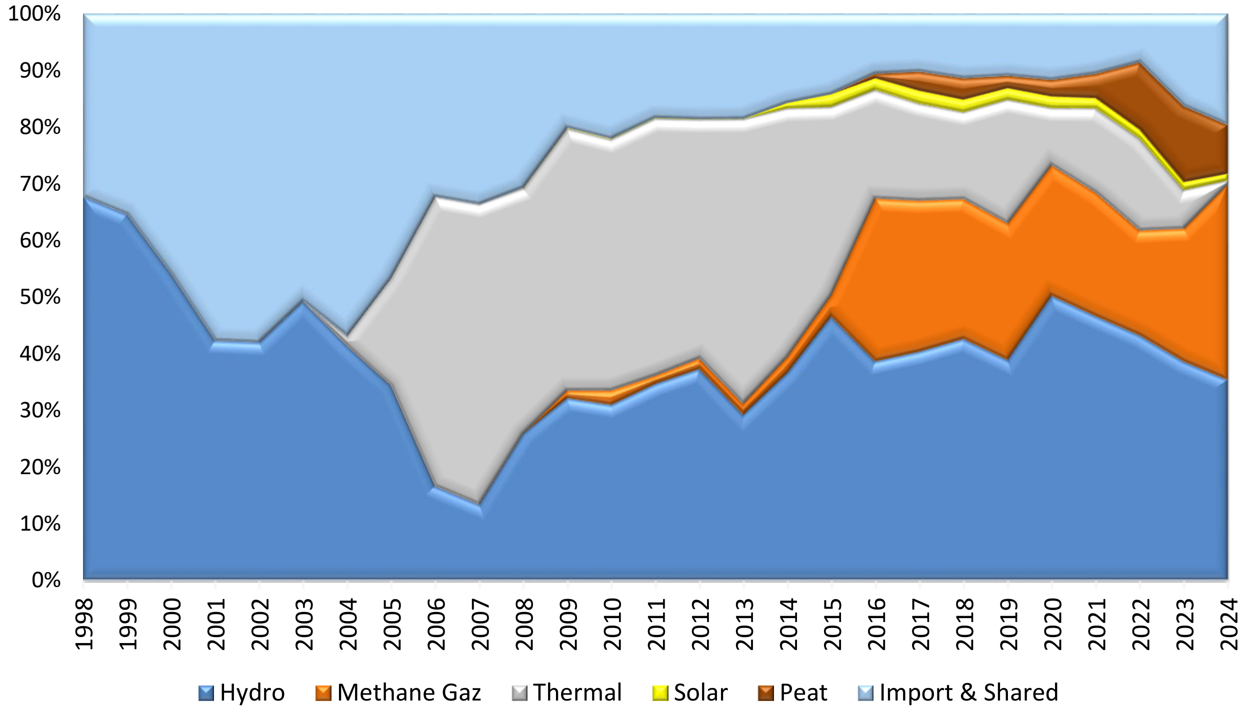


Figure 7: Evolution of the electricity generation mix

The total generation capacity has increased to 466 MW from the previous 406 MW. More specifically, the following changes were made in the fleet of installed power generation capacity in 2024:

Table 4: Recently commissioned PPs

#	Power Plant	Installed Capacity (MW)	Technology Type
1.	UETCL Imports (Mbarara -Shango)	30	Import
2.	Shema Power Lake Kivu (SPLK)	56	Methane
3.	Rusumo Regionally shared Power Plant	26.7	Hydro/Import
	TOTAL	**112.7**	

Table 5: Decommissioned power plants

#	Power Plant	Installed Capacity (MW)	Technology Type
1.	SO-Energy	-30	HFO/Diesel
	TOTAL	**-30**	

5. Planned Committed Projects

To reduce the high levels of dependence on diesel power generation, different generation expansion scenarios were created and modelled (including interconnection to the Ugandan grid as the recent 40 MW import contributed to the reduction of diesel dependency) while awaiting smooth on-boarding of Rusumo Regional HPP and SPLK). This allows envisioning the use of different technologies to generate electricity on the Rwandan grid. Commissioning dates of key near-term planned projects (outlined in table 6 below) were also used to constraint the model while determining the optimal generation mix for the country in the medium term.

Table 6: Planned Generation Projects (Committed)[8]

#	Power Station	Nominal Capacity (MW)	Estimated COD
	Non-renewable power plants		
1.	Kivuwatt Phase_2 extension	9	TBD
2.	SPLK Phase_2 extension	28	TBD
	Small Hydropower Stations (<=5MW)		
3.	Izuba CB Energy Rwanda	4.13	2025
4.	Nyirahindwe 1	0.909	2025
5.	Nyirahindwe 2	0.359	2027
6.	Muvumba Multipurpose Dam	1	2027
7.	Ngororero	2.7	2027
8.	Nyundo	4.5	2027
9.	Rwondo	2.3	2027
10.	Base 1	2.9	2027
11.	Kore	1.3	2025
12.	Rucanzogera	1.9	2028
13.	Rukore	2	2028
14.	Bihongore	4.22	TBD
	Medium to Large Hydro Stations (>5MW)		
15.	Rukarara VI	9.76	2027
16.	Nyabarongo II	43.5	2027
	Solar PV		
17.	Nyabarongo2 Solar PV	100	2027
18.	Rwanda Solar Park	100	2028
	Power trade		
19.	Additional imports	30	TBD
	Regional Projects (hydro)		
20.	Rusizi III	68	2031
21.	Rusizi IV	95.9	TBD

8 TBD : To Be Determined.

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, and 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 and imports), as well as seasonal inputs from the big hydro storage power plants on the system.
- A power network analysis[9] 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 Sustainable Development Goal no. 7 set by the United Nations (i.e. affordable and clean energy), existing policies 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[10] was set to ensure alignment 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.
- 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, and mainly for purposes of serving the peak demand which lasts for an average of 3 hours every day. 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

9 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.

10 Energy Sector Strategic Plan (ESSP) & SE4All Rwanda Action Agenda

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 and found to be a key consideration, especially in latter half of the planning horizon.
- 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 & 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.

5.1.1. Future Plans

- A nationwide resource study has been conducted to have a deeper and more recent understanding of all the resource potential that exists in Rwanda that can be exploited for electricity production. The results from this resource study have been used in this update and will continue to be used in subsequent LCPDP updates. With a focus on renewable resources, this study estimated physical availability, technical potential, economic as well as market potential of seven generation resources, namely hydro, solar, wind, peat, methane, waste/biomass, and geothermal.

- To further consolidate the gains achieved in least cost generation planning, a climate change mitigation assessment will be conducted with emphasis on decarbonisation policy scenarios to enrich future LCPDP updates with an economy-wide assessment to achieve net-zero GHG emissions by 2050. By reviewing the current status and future trends of GHG emissions in Rwanda, this assessment should contribute to the identification of suitable policy options.

6. Least Cost Generation Expansion Planning Methodology

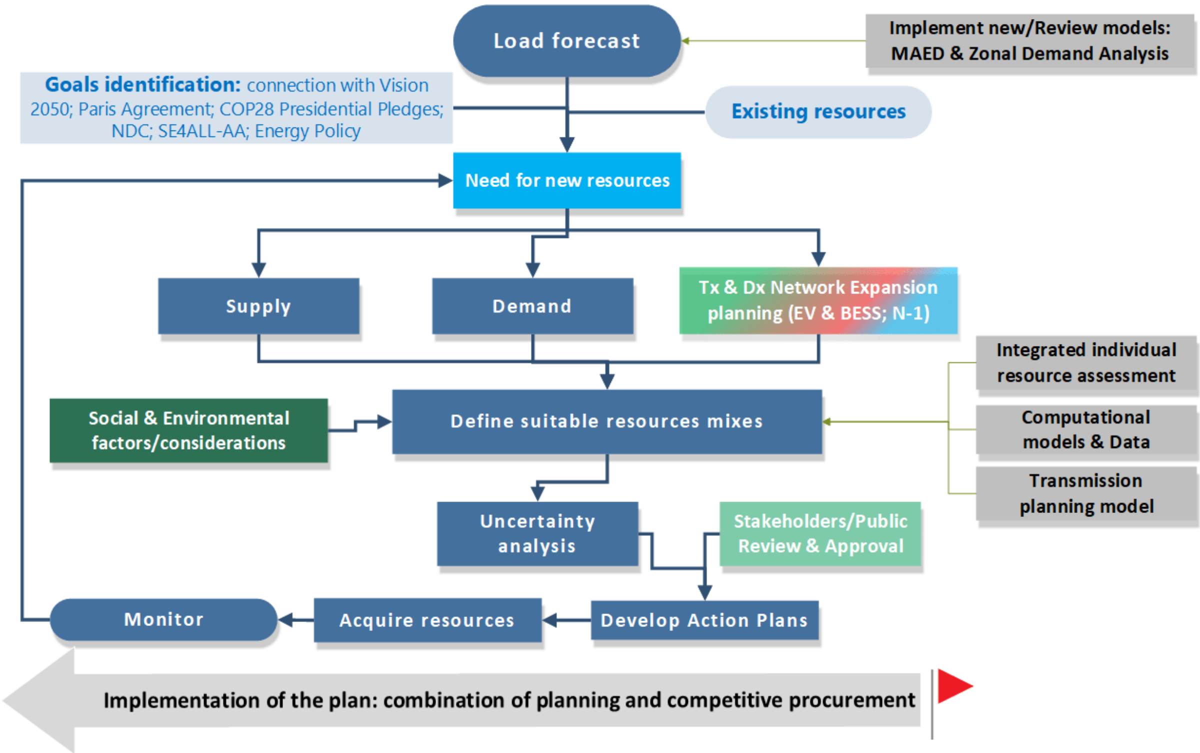


Figure 8: Main processes in generation expansion planning-an integrated perspective

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 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 and conversion (***supply***) to transmission and distribution of energy services (***demand***).

The underlying principle of the model is <u>the optimization of an objective function (in our case least-cost expansion: the discounted cost of energy supply from various sources) under defined constraints</u>.

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

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

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

Equation 2: Objective Function

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.

$$\sum \text{Supply} \geq \sum \text{Demand at all points in time.}$$

Equation 3: Demand Equation

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.

$$\sum \text{Production} - \sum \text{Consumption} \geq 0$$ 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.

Equation 4: Balance Equation

3. *Resource Equation*: The amount of depletable resource used to build capacity must be less than the number of existing available reserves.

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, etc. 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, etc.

MESSAGE has the unique ability of modelling seasonal (renewable) supply alternatives through the use of seasonal supply divisions[11], which suits the hydro dominant supply existing within Rwanda[12], as shown in figure 9 below.

11 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.

12 See total installed capacity vs firm capacity difference in Table 2

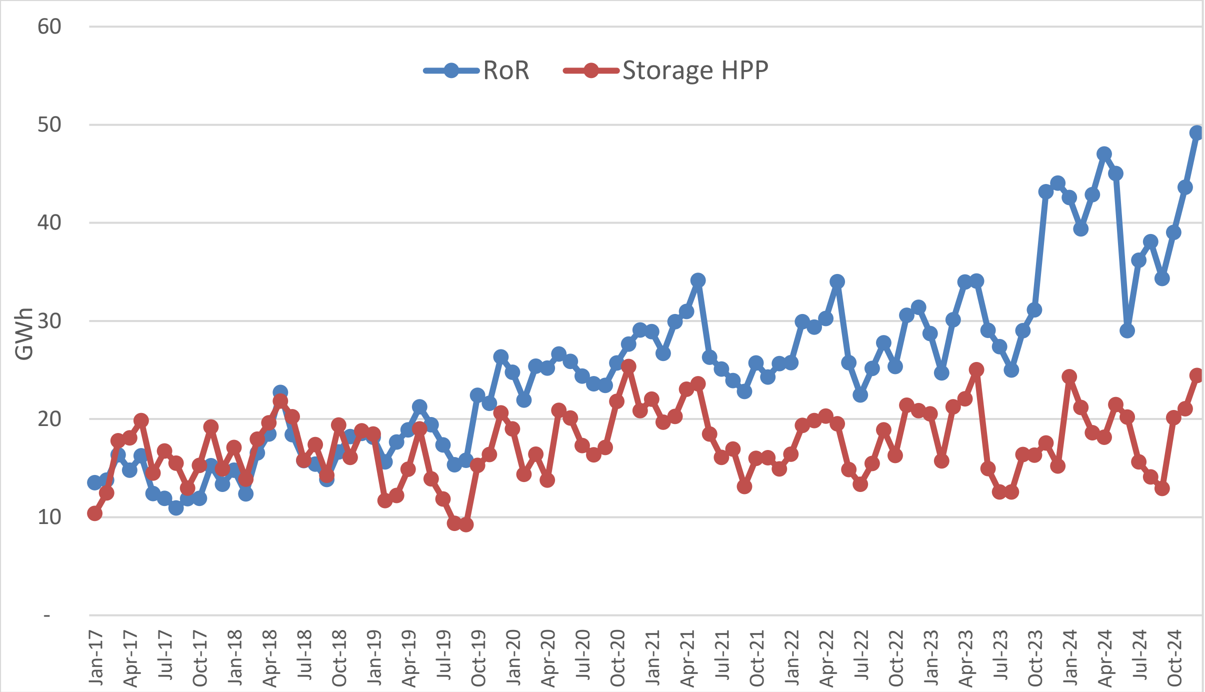


Figure 9: Hydro Power Plant Seasonal Variation

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 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 more 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. The key resources making up the energy expansion options include:

Peat: Peat generation is currently limited to Gishoma and Hakan, with a combined nominal capacity of 85 MW, of which Hakan peat-to-power plant is the largest power station in Rwanda, with a nameplate capacity of 70MW. A 2016 report concluded that from the 13,571-ha area studied, approximately 23 - 33 million dry tonnes of peat can be produced from an exploitable area of 4,057 ha. This peat can produce between

97 - 129 TWh over 30 years, at an estimated level of between 121 - 161 MW[13].

Methane gas: Methane gas contained within Lake Kivu is Rwanda's largest natural resource. Formation of these reserves was due to the unique geology of the lake, resulting in the naturally regenerating methane gas that is found there. Lake Kivu contains 60-70 km^3 of methane, of which 44.7 km^3 can be extracted, with an annual accumulation of 0.14 km^3. The amount of electricity that can be generated from this methane depends on extraction efficiency. This efficiency is currently estimated at 28%, which is significantly lower than the expected 40-60%. Currently, the main focus concerning this resource is its extraction for electricity generation. However further investigations are currently underway to fully understand its potential applications in the commercial, industrial and residential sectors of the country.

Hydro power: Rwanda is located within the equatorial belt; its climate is strictly not of the equatorial rainy type. It has a modified humid climate including rainy forest and Savannah types. The central and eastern part of the country is generally of semi-arid type owing to its position in the rainy shadow of the western highlands. 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.

Wind energy: A rapid wind energy resource assessment was carried out in Rwanda in five locations over the course of 2011. Preliminary indications from the analysis of recorded field measurements of wind speeds and climate data were that most of Rwanda is not highly suitable for wind energy. The Eastern Province was identified as the location with the most promising potential. Another academic study using modelling analyses based on recorded wind measurements at selected Rwandan meteorological stations noted that electricity production in the area of the Gisenyi station could be possible with a good mean value of both wind speed and power density. In contrast, in areas such as Kigali, Butare and Kamembe, wind energy potential is only enough for windmills or water pumping for agricultural and intuitional needs.

Solar energy: Rwanda's solar radiation and solar resources have been assessed by the U.S. National Air and Space Agency (NASA) as well as the University of Rwanda. Rwanda's Eastern Province has the greatest potential for generating energy from solar resources. The International Renewable Energy Agency (IRENA) published a study identifying potential high-yield solar PV zones within the Africa Clean Energy Corridor. These findings for each zone within Rwanda were identified, such that all site-specific production activity was modelled as accurately as possible. Another academic assessment, undertaken in partnership with the

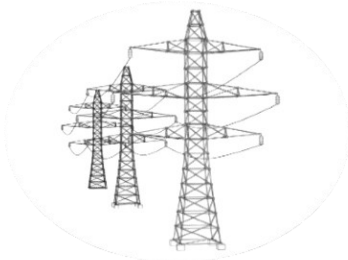
13 Rwanda ESSP 2018.

MININFRA Department of Meteorology in 2007, used meteorological data set to estimate monthly averaged global solar radiation. This was found to vary from 4.3 - 5.2 kWh/m^2/day throughout the country. The Rwanda Resource Study for Electricity Generation Sources took a step further to estimate various solar PV technological potential, ranging from traditional ground-mounted PV systems to agri-photovoltaic, floating PV, and commercial& industrial and well as residential rooftop solar, placing this resource in a significant role as an energy transition option.

Geothermal: Geothermal energy refers to the heat found within the earth. This can be harnessed by drilling into the ground and using steam to drive generators. Rwanda's geothermal resources are yet to be proven. However, studies have identified Karisimbi, Kinigi, Gisenyi and Bugarama as promising areas.

Waste/biomass: Small-scale power generation using agricultural residues (such as bagasse or rice husks) or biomass briquettes (from compacted waste residues or charcoal dust) is feasible, but at rather low levels of capacity. However, with socio-economic transformation, effective urbanization can bring the potential of municipal waste-to-power, characteristics of cities that the country aspires to attain in the horizon 2035-2050.

Import/Export options: these are considered as alternative to supply peak demand which is usually supplied mostly by fossil fuel powered plants, which makes importation of diesel a priority to the power generation. In addition, the discovery of natural gas reserves off the coast of neighboring Tanzania, interest throughout Rwanda has been sparked concerning tapping into this resource potentially at a relatively cheaper cost for several purposes.



- **Sources of Energy**

Non-exhaustible/renewable resources such as solar, hydro, biomass, geothermal, etc are modelled differently for most 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**

<u>Technical characteristics include:</u>

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.[14]

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).

ii. **Fixed costs**[15] – 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 (generic technologies) were also considered and added to the model. These include:

i. Solar PV (grid-connected utility-storage)[16].

14 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.

15 This was used to model the take-or-pay contracts PPA structure that exists within the Rwandan context.

16 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.

ii. Hydro Pumped Storage.
iii. Waste-to-Power/Biomass Generation.
iv. Battery Energy Storage Systems.
v. Natural Gas Fired PPs[17].
vi. Methane Power Plants Capacity Addition[18].
vii. Peat Power Plant Capacity Addition[19].
viii. Nuclear Power Plant Capacity Addition (SMR).
ix. Geothermal
x. Green Hydrogen
xi. Distributed Wind generation

6.1.3. Other user-specified data

This section consider any activity going on in the supply system, and that is relevant to the objective of the 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., 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 (c):** 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.

17 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.

18 Exploitation of existing methane reserves in the country.

19 Exploitation of existing peat within the country.

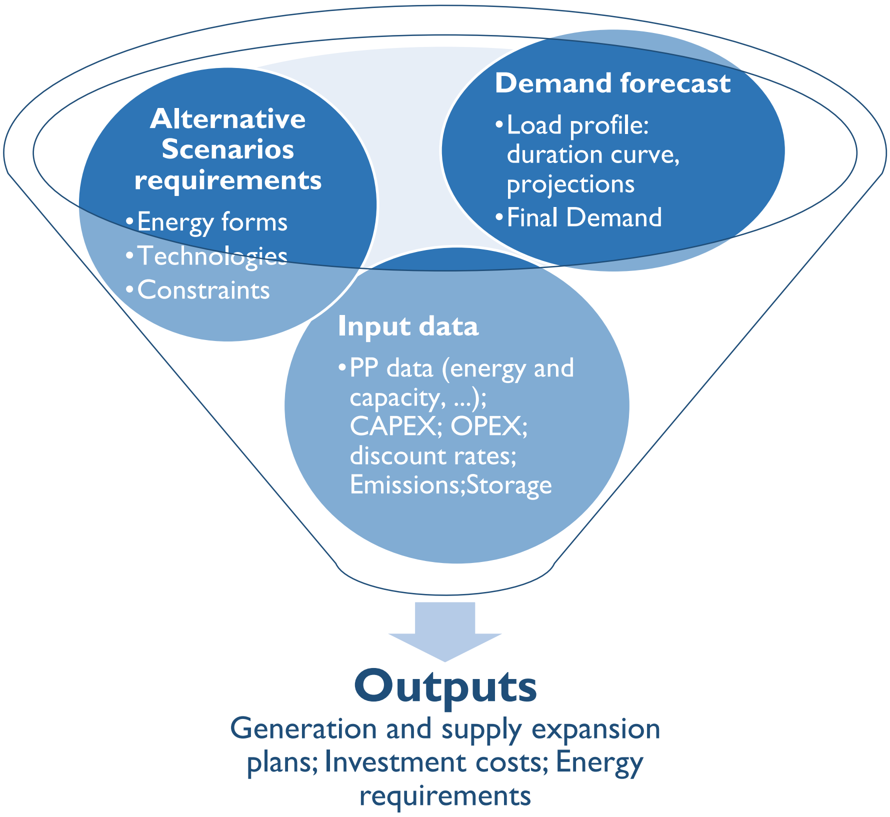


Figure 10: Processes in MESSAGE

6.3. Generation Expansion Scenarios:

This version of the LCPDP expands export possibilities as well as demand forecasts for even lower costs and higher profits for the company. An analysis of different scenarios using demand growth forecasts, and various resources combination in the generation fleet and times as key factors to find the least cost development path was conducted.

All scenarios were simulated with their different conditions and ran; the least cost development path/scenario was selected. The total generation cost per scenario was computed for each scenario and the least-cost option selected. A total of 8 scenarios are studied and a summary is presented in tables 7 and 8 below.

The reference scenario was constructed based on the current and near-term features of the generation supply: dominance of hydro power generation, on-going or committed generation projects in the pipeline such as committed interconnections, In the latter half of the planning horizon, the generation supply gap is filled with imported natural gas. Diesel fuelled power plants are kept at 30 MW for emergency use.

Table 7: Summary description of studied scenarios

ID	SCENARIO NAME	KEY SUPPLY CONSIDERATIONS/MAIN FEATURES
1	Reference Scenario (Business As Usual)	• Demand growth: 10% throughout 2050 • All existing PPAs and commitments by the GoR on upcoming PP, and projects in the pipeline • Introduction of Utility-Scale Solar PV integrating storage, Geothermal; Green H2; Natural gas pipeline; • Power trade (imports & exports are) restricted to 66% of the interconnection carrying capacity (600 MW by 2050).

ID	SCENARIO NAME	KEY SUPPLY CONSIDERATIONS/MAIN FEATURES
		• Power trade at 20% of total energy demand. • Renewable energy share constraint moderately applied i.e., not necessarily achieving ≥ 60% RES
2	Domestic Generation	• Demand growth: same as in Reference Scenario • All existing PPAs and commitments by the GoR on upcoming PP, and projects in the pipeline. • Domestic production, restricting imports & exports. Power trade restricted to 15% of power generation/total demand. • Renewable energy share constraint moderately applied i.e., not necessarily achieving ≥ 60% RES
3	Power Trade & Interconnections	• Demand growth: as in Reference Scenario. • All existing PPAs and commitments by the GoR on upcoming PP, and projects in the pipeline. • Supply mainly driven by the penetration of imports/interconnections. • Power trade restricted to 30% of power generation/total demand. • Renewable energy share constraint moderately applied, i.e., not necessarily achieving ≥ 60% RES
4	Renewables	• Demand growth: as in Reference Scenario. • All existing PPAs and commitments by the GoR on upcoming PP, and projects in the pipeline. • Power trade at 20% of total energy demand. • Supply mainly driven by REs to achieve the policy target of 60% of RE in the power generation mix.

For each supply-side scenario presented above, sensitivity is conducted with two high demand growth scenarios (first a 12% annual demand growth throughout the horizon 2050, as well as a 15% demand growth till 2030 and 12% afterwards) are modelled and tested and the key results are presented in Table 8.

The main objective of the *Reference Scenario* is to model and understand expansion in the business as usual. The *Domestic Generation* demonstrates the resilience of domestic generation supply to meet demand. The *Power Trade & Interconnections* scenario studies the implications of interconnections on generation supply. The *Renewables* scenario restricts new technologies additions to renewables. The *High Demand Growth* case is used to understand the requirements of an accelerated growing demand on electricity generation, especially after 2030.

Table 8 below presents a summary comparison of different scenarios for selected key metrics to guide the understanding of the implications of different expansion paths.

Table 8: Summary comparison of various studied scenarios[20]

Metric/Indicator		Reference Scenario (Business As Usual)			Domestic Generation			Power Trade & Interconnections			Renewables		
		Demand Δ (10%)	Demand Δ (12%)	Demand Δ (15% till 2030 & 12% after)	Demand Δ (10%)	Demand Δ (12%)	Demand Δ (15% till 2030 & 12% after)	Demand Δ (10%)	Demand Δ (12%)	Demand Δ (15% till 2030 & 12% after)	Demand Δ (10%)	Demand Δ (12%)	Demand Δ (15% till 2030 & 12% after)
Installed Capacity (MW)	2030	596	650	754	596	651	773	601	659	819	595	637	795
	2050	3862	6224	7592	3774	6918	7487	6462	6583	9193	6027	9169	11280
Total Demand (GWh)	2030	2604	2889	3395	2604	2889	3386	2608	2903	3389	2603	2890	3379
	2050	17503	28032	32847	17538	28019	32721	17512	28033	32504	17360	27489	32194
Imports (GWh)	2030	176	176	176	176	176	176	176	176	176	176	176	176
	2050	176	176	176	176	176	178	176	187	328	313	176	176
Renewable energy share (%)	2030	64%	65%	56%	64%	65%	56%	64%	65%	55%	64%	66%	66%
	2050	37%	35%	28%	35%	34%	34%	61%	35%	43%	61%	61%	63%
Exports (GWh)	2030	-46	-46	-46	-46	-46	-46	-46	-46	-46	-46	-46	-44
	2050	-579	-579	-579	-579	-579	-579	-595	-595	-579	-579	-579	-579
Total Discounted Cost of Energy Supply (USD M)	2050	4825	5934	6852	4817	6001	6782	4893	5951	6801	4827	6037	7505
Expansion scenario costs relative to the Ref. scenario and the least cost scenario (USD M)	Rfr	N/A	N/A	N/A	-8	67	-70	68	17	-51	2	103	653
	LC	8	0	70	0	67	0	77	17	19	10	103	723
Peak Demand (MW)	2030	428	477	559	428	477	559	428	477	559	428	477	559
	2050	2881	4602	5393	2881	4602	5393	2881	4602	5393	2881	4602	5393

Note: For each variable except the total discounted cost of energy supply, the first line corresponds to values in 2030 and the second line in 2050.

[20] For each variable except the *total discounted cost of energy supply*, the first line corresponds to values in 2030 and the second line in 2050

7. December 2024 Assumptions & Updates

7.1. Assumptions:

Reference scenario key features:

The reference scenario is built upon several key assumptions to ensure a balanced and sustainable expansion of Rwanda's electricity generation system. A steady 10% annual demand growth is projected throughout the planning horizon until 2050, requiring a robust and adaptable energy infrastructure.

In terms of power trade and interconnection, electricity imports are expected to reach up to 66% of the designed carrying capacity of current interconnections. Additionally, exports will be strategically aligned with opportunities arising from the Eastern Africa Power Pool (EAPP) day-ahead market, leveraging available wheeling mechanisms to enhance regional electricity trading.

To optimize existing power generation assets, capacity expansions are planned for key facilities. Specifically, SPLK Phase 2 will add 28 MW, while Kivuwatt Phase 2 is expected to contribute an additional 8-9 MW, and KP1 will see a 3.6 MW increase. These upgrades aim to maximize efficiency and meet rising electricity demand with minimal additional investment.

In the longer term, Rwanda's energy mix will incorporate a broader range of renewable energy technologies. Future developments will include utility-scale solar photovoltaic (PV) systems integrated with storage, hydro pumped storage, and consumer-sized battery storage systems to enhance grid stability. The potential of green hydrogen technology and municipal waste-to-energy conversion will also be explored, along with further investment in geothermal power and wind energy to diversify the country's generation portfolio.

To further address the challenges of growing electricity demand, new technologies will be introduced, including natural gas-fired power plants and small modular nuclear reactors (SMRs). These additions will support grid reliability while reducing dependence on imported fuels.

Finally, the strategy includes the phasing out of rental thermal (diesel-fired) power plants in alignment with national decarbonization pathways and economic dispatching strategies. However, adequate reserves will be maintained for emergency response and ancillary services, ensuring system stability during peak demand periods and unexpected supply fluctuations.

These assumptions collectively form the foundation for Rwanda's least-cost power development strategy, balancing economic efficiency, environmental sustainability, and long-term energy security.

I. Demand forecast: 10% throughout 2050

II. Power trade/Interconnection throughout 2050:

   a. Electricity imports of up to 66% of current interconnections designed carrying capacity equivalent to about 600 MW.

b. Export considering wheeling arising from the potential of the EAPP day-ahead market[21].

III. Optimization of Existing Power Plants:
   i. SPLK Phase_2: 28 MW
   ii. Kivuwatt Phase_2: 8-9 MW
   iii. KP1: 3.6 MW

IV. Introduction of technologies based on renewable energy sources in the longer term:
   a. Utility-scale Solar PVs (with storage)
   b. Hydro pumped storage
   c. Consumer-size electric batteries storage systems
   d. Green hydrogen generation technology
   e. Municipal waste-to-power
   f. Geothermal power production potential
   g. Wind generation

V. New technologies included to cope with growing demand
   a. Natural gas
   b. Nuclear power generation (SMR)

VI. Phasing off rental thermal (diesel fired PPs) based on BAS (national decarbonisation pathways, and economic dispatching)-Retaining adequate reserves for emergence use and ancillary services.

7.2. Updates:

- Update and realignment of CODs of power plants[22]
- Model base year to 2024, with projections throughout 2050.
- Updated demand assumptions/inputs (informed by Demand Analysis, (MAED, 2022,) inputs and 5th RPHC Census key results and anticipated major loads.
- Consideration for utility-scale battery energy storages systems
- Addition of hydro pumped storage
- Incorporate insights from the generation resource assessment study:
   a. Solar PV systems integrating storage.
   b. Update cost estimates for solar PV and battery storages.
      i. especially in the longer planning horizon to reflect the global declining trends in the cost of these technologies, and advances in capacities.
   c. Generic distributed wind generation
   d. Geothermal-fuelled power generation

21 This is does not consider the potential for power wheeling and does not constitute any limit of the exporting capability. Future updates/review will dynamically reflect prospects as new technical details emerge.

22 Nyabarongo_2 (CoD to 2027), Rusizi III (CoD to 2031), Nyirahindwe I & II (2026 & 2027), Nyundo (2027/8), Base I (2027), Ngororero (2027) & Rwondo (2028).

8. System Expansion Results

8.1. Reference Scenario

With assumptions as listed in section 7.1 above, simulations were conducted and resulted in the capacity and energy generation profiles as presented below in Figure 11 through Figure 13 and in Table 9 across two horizons, the immediate short to medium term and the longer horizon:

8.1.1.a Installed Power Generating Capacity in the Short to Medium Term: 2025 – 2031

Figure 11 below shows the total domestic installed capacity over the next 6 years.

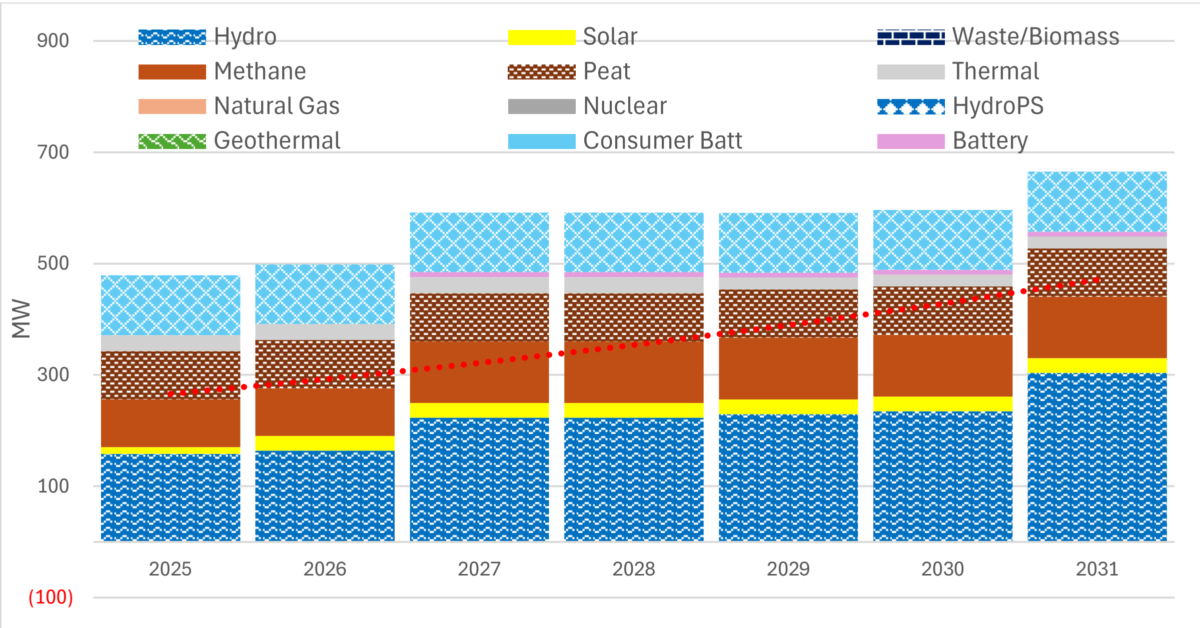


Figure 11: Total domestic installed capacity (MW) and peak demand in the near term 2025-2031

- For the installed capacity in the short term 2025-2031 to be enough to satisfy the annual growing demand and reserve margin requirements, the following capacity additions are needed in addition to optimising existing power plants:
  - Nyabarongo-2 hydro power plant
  - Rusizi-3 Regional Hydropower Plant
  - 38.28 MW of Solar PV capacity integrated with storage
  - Scaling up existing methane-fire power plants by at least 25 MW
  - Rukarara VI hydropower plant

Total installed capacity of thermal (diesel) powered plants remains at 28.80 MW[23]. However, upgrading Jabana1 from 7.8 MW to 30 MW is required to maintain a higher reserve margins 15%, especially in the event of extreme seasonal variations.

Excess capacity of about 40 MW (off-peak and shoulder hours) exists that can be used for battery storage or for export, adding to domestic demand and significantly increase potential company earnings.

23 Jabana I and II diesel-power plants.

8.1.1.b Installed Power Generating Capacity in the Longer horizon: 2032 – 2050

Figure 12 shows the evolution of total installed capacity of generation supply technologies on the Rwandan grid.

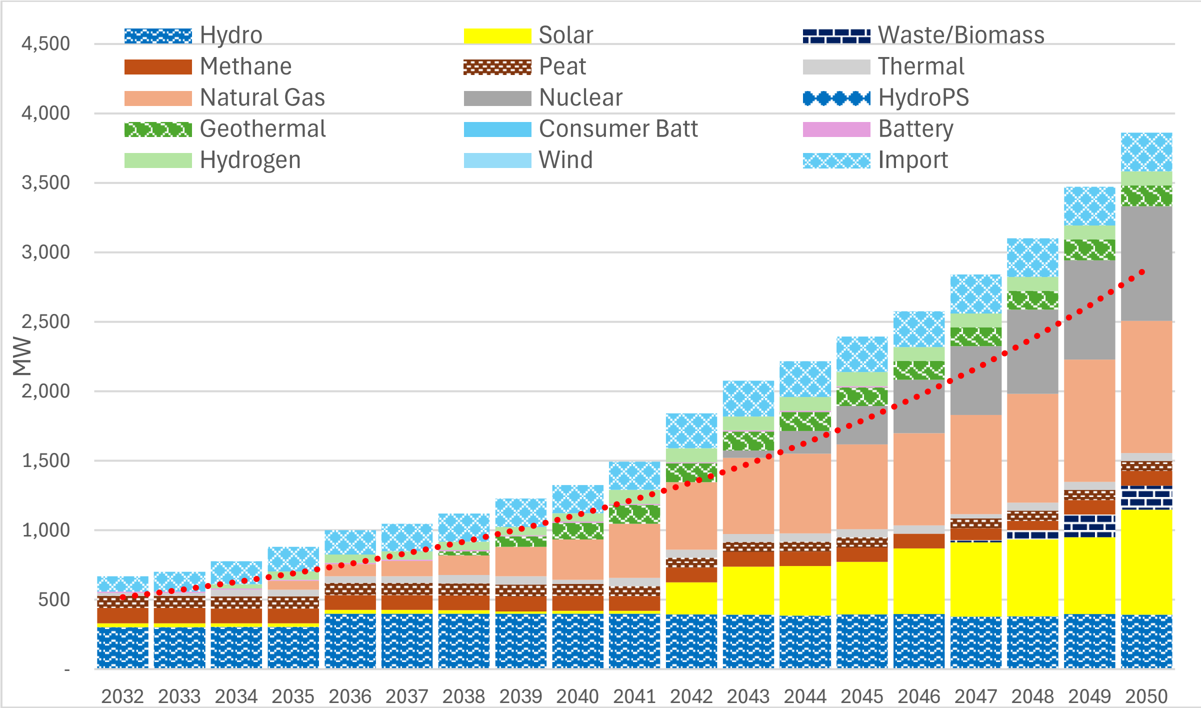


Figure 12: Total Installed Capacity (MW) and peak demand in the longer term 2032 - 2050.

New supply technologies are added onto the grid to satisfy demand. These include natural gas, utility-scale solar PV, consumer battery storages with projected required installed capacity as outlined below:

- 392 MW of Hydro Power.
- 950.9 MW of natural gas installed capacity.
- 30 MW of standby/emergence capacity.
- 150 MW of Generic Geothermal.
- 757 MW of Solar PV embedded with storage.
- 172 MW of Waste to Power.
- 825 MW of Nuclear-SMR.
- 100 MW of Green Hydrogen
- 105 MW of Methane-fired power plant
- 279 MW in power traded capacity.

The total installed capacity rise consistently above the red line (peak demand), indicating that planned additions provide a comfortable reserve margin over the entire period. The gap widens substantially from the early 2040s onward, suggesting a proactive strategy to meet future consumption and ensure supply security.

Hydropower remains a core component, but newer technologies begin to occupy an increasing share of the total installed capacity as the horizon extends. This reflects Rwanda's aim to leverage its existing hydro resources while gradually diversifying to reduce dependency on a single energy source.

Large additions of natural gas generation appear from the mid-2030s onward, becoming a significant contributor to overall capacity. Later, nuclear emerges toward the 2040s, expanding to a notable share by 2050. These two firm, low-emission (or lower-emission) sources help meet rising demand reliably, complementing renewables.

Solar and various new technologies (hydrogen, wind, geothermal, waste/biomass) steadily gain importance, especially in the 2040s. Their presence underscores a deliberate approach to integrate cleaner, more flexible systems (e.g., HydroPS, battery storage) that support grid stability and address variability from renewables like solar and wind.

A visible share of import capacity is maintained or grows over time, suggesting that cross-border electricity trade will remain an important strategy—either for economic dispatch or to balance local supply fluctuations, in line with broader regional market opportunities.

By 2050, the total installed capacity significantly exceeds peak demand, aligning with policy objectives to ensure resilience against hydrological variability, demand surges, and unforeseen outages. While this planning margin adds reliability, it also highlights the need to manage potential cost implications of underutilized capacity.

The increasing share of renewable and lower-carbon technologies (solar, wind, geothermal, hydrogen, nuclear) aligns with long-term climate goals and reduces exposure to fuel price volatility. Meanwhile, gas and strategic imports remain important for ensuring dispatchable power and bridging seasonal gaps, especially in a high-demand growth scenario.

8.1.1.c Electricity Production & Demand:

Figure 13 and table 9 provide a 5-year time step of the annual production profiles of each technology type during this planning horizon.

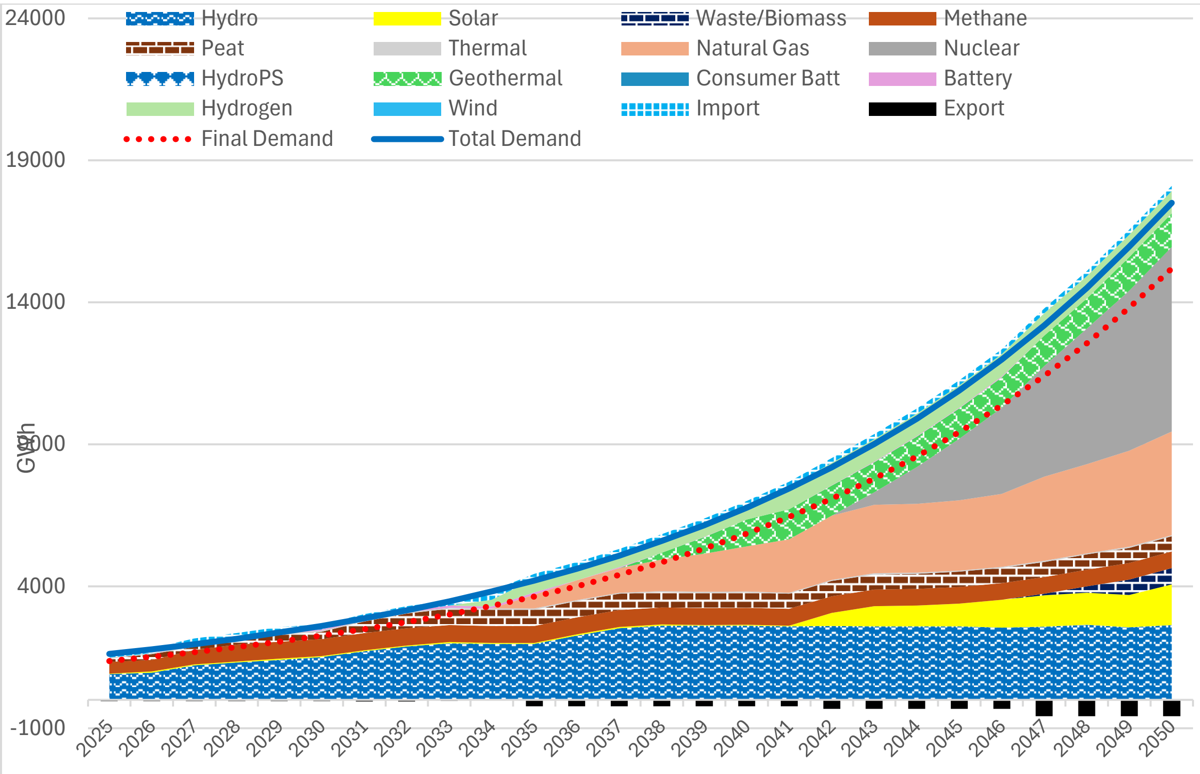


Figure 13: Production per Technology Type (GWh)

Growing Reliance on Hydropower, Then Diversification : Hydro remains the foundational resource across the planning horizon. However, as total production expands, other sources (natural gas, nuclear, peat, and various renewables) take up a larger share, reflecting Rwanda's shift toward a more diversified and resilient energy mix.

Emerging and Advanced Technologies : Over time, the chart shows notable contributions from nuclear, natural gas, and renewables (solar, wind, geothermal, hydrogen) in the 2040s and beyond. This indicates growing technology diversity to meet surging demand and aligns with broader goals of reliability and decarbonization.

Export Potential : The black bar segments toward the top represent exported electricity. As domestic production increasingly exceeds local demand, exports become a more prominent slice of total output. This supports the national objective of enhancing regional trade and earning revenue from surplus capacity.

Overall, the chart illustrates Rwanda's pathway toward a robust, multi-resource generation portfolio by 2050—anchored in hydropower yet increasingly supported by a range of complementary technologies. This trajectory positions Rwanda to meet growing domestic demand while capitalizing on export opportunities in the regional electricity market.

It is clear that hydro dominance persists in the short to medium term planning horizons. Peat production also increases to satisfy the domestic demand. In addition, thermal requirements are minimized. This is due to the least-cost selection of supply from imports and other available cheaper and renewable energy generation options within this time period. Production from nuclear begins and contributes significantly after 2035 as installed capacity requirements increases.

Table 9: Production (GWh) per Technology Type

Year	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Domestic Production	**1488.9**	**2476.3**	**4259.1**	**6826.7**	**11071.4**	**17923.8**
Hydro	908.2	1,505.5	1,968.7	2,611.5	2,584.9	2,629.5
Solar	15.0	36.8	36.6	33.5	805.8	1,437.3
Waste/Biomass	-	-	-	-	-	572.6
Methane	414.5	600.5	600.5	600.5	585.9	585.9
Peat	112.4	257.2	570.6	535.4	535.4	535.4
Thermal	38.8	38.8	38.8	38.8	38.8	38.8
Natural Gas	-	-	494.2	1,586.4	2,474.7	3,649.1
Nuclear	-	-	-	-	2,168.1	6,504.3
HydroPS	-	-	-	-	-	-
Geothermal	-	-	-	946.1	1,064.3	1,182.6
Consumer Batt	-	-	-	-	-	-
Battery	-	37.5	76.6	1.6	25.2	-
Hydrogen	-	-	473.0	473.0	788.4	788.4
Wind	-	-	-	-	-	-
Power trade	**130.6**	**130.6**	**-52.4**	**-52.4**	**-140.0**	**-402.8**
Import	176.2	176.2	176.2	176.2	176.2	176.2
Export	(45.6)	(45.6)	(228.6)	(228.6)	(316.2)	(579.0)
Total Supply	**1619.5**	**2606.9**	**4206.6**	**6774.2**	**10931.4**	**17521.0**
Grid Losses	**251.9**	**345.8**	**563.3**	**908.6**	**1463.6**	**2313.7**
Transmission Losses	50.0	77.8	130.1	209.4	336.0	533.1
Distribution Losses	202.0	268.0	433.2	699.2	1,127.6	1,780.6
Final Demand	**1366.2**	**2257.8**	**3636.2**	**5856.1**	**9431.4**	**15189.3**

Year	2025	2030	2035	2040	2045	2050
Total Demand	**1618.1**	**2603.6**	**4199.5**	**6764.7**	**10895.0**	**17503.1**

8.2. Demand-Side Scenarios

As presented in section 3 of demand forecasting, the scenarios presented in this section are intended to reflect the post-recovery medium-term prospects slightly beyond the long-term trajectory (10%). Thus, the recommendation will be based on the alternative case 15% and 12% annual demand outlook.

The resulting medium-term priorities in addition to the reference scenario presented in section 8.1.1.a:

- Accelerate small and medium hydropower projects: 22.26 MW in small and micro hydropower plants (Nyirahindwe 1&2, Muvumba Multipurpose Dam, Ngororero, Nyundo, Rwondo, Base 1, Kore, Rucanzogera, Rukore, Bihongore)
- Fastrack Development of grid energy storage 20-30MW
  - BESS
  - Hydro pump storage
- 30 MW of imports
- Fast-track planning and project development around Nuclear SMR technology.
- Increase standby/emergence capacity to 24 MW to cope with high demand especially to counter potential project delays.
- Increase solar PV (BESS embedded) generating capacity to 253 MW.

8.2.1. Alternative Reference Scenario 12% Annual Demand growth

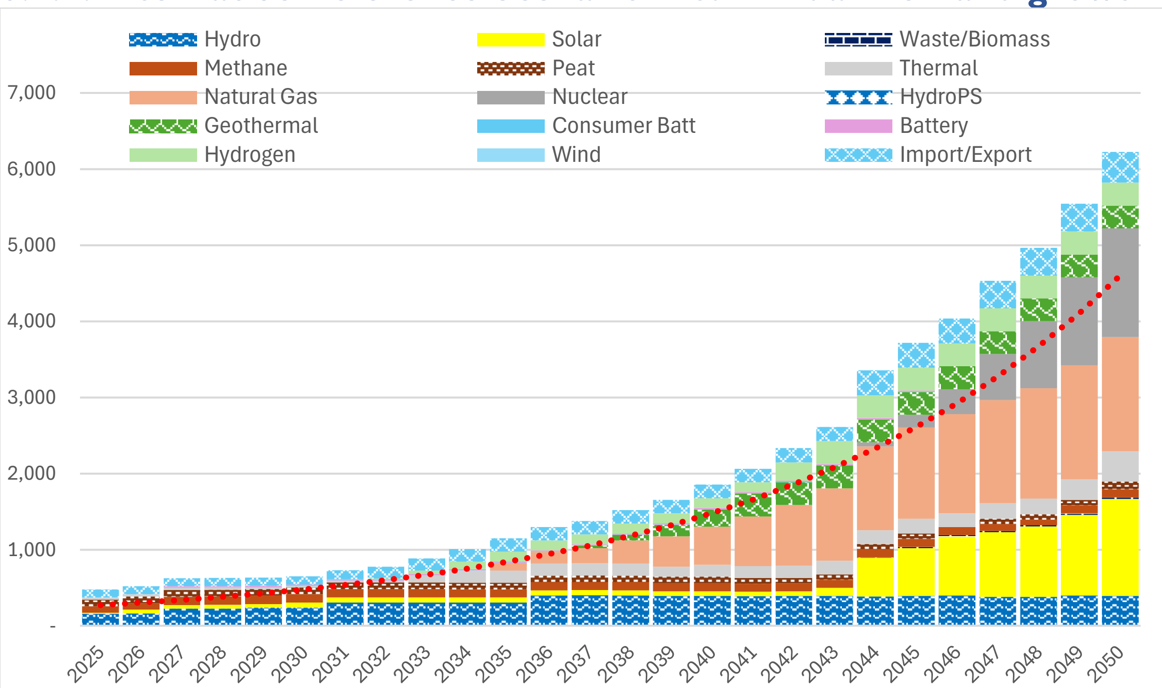


Figure 14: Installed Capacity in the alternative demand scenario: 12% annual demand growth

- Steady Capacity Growth: From about 2025 onward, total installed capacity steadily expands and stays above the dotted red line (peak demand). By 2050, capacity approaches 6,500 MW, indicating a comfortable reserve margin to handle seasonal fluctuations or unexpected outages.

- Diverse Technology Mix : Hydropower continues to provide a sizable base, but natural gas, solar, nuclear, wind, and geothermal gradually take on larger shares as demand rises. This highlights a deliberate move toward diversified, lower-carbon resources.

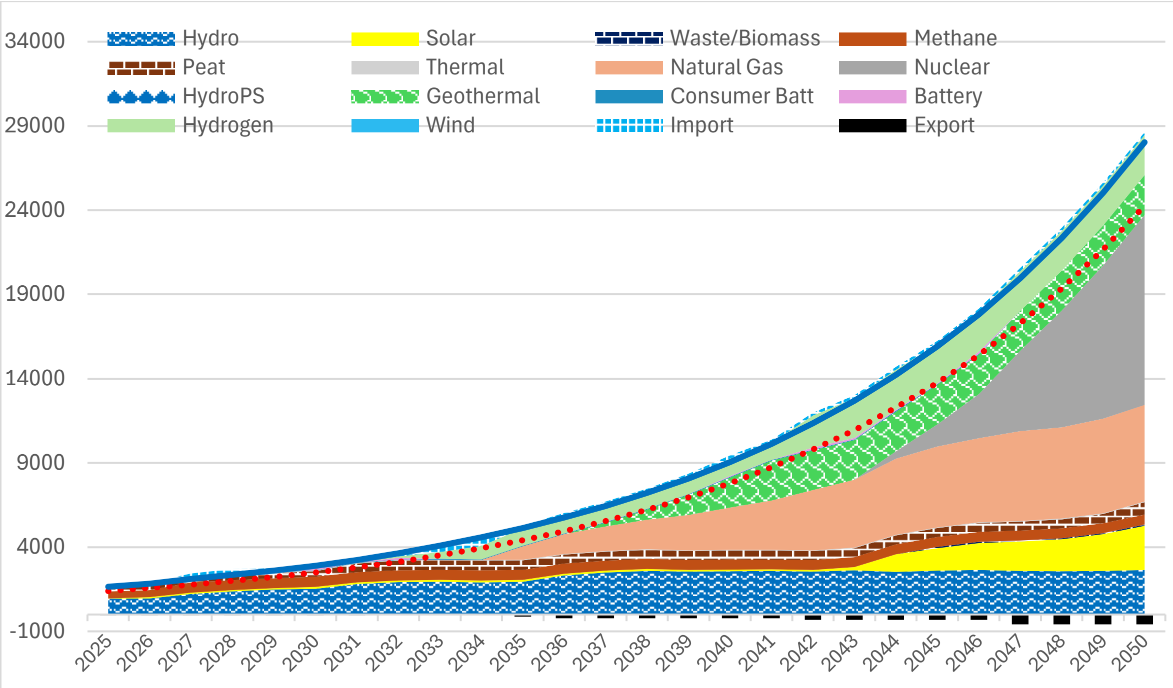


Figure 15: Electricity generation (GWh) in the alternative demand scenario: 12% annual demand growth

Total electricity production grows from a few thousand gigawatt-hours in 2025 to nearly 30,000 GWh by 2050, in line with a 12% annual demand growth rate.

Natural gas and nuclear become significant contributors, balancing out intermittent renewables and maintaining a stable output as electricity requirements climb sharply.

8.2.2. Alternative Reference Scenario 15% Annual Demand growth till 2030 and 12% afterwards

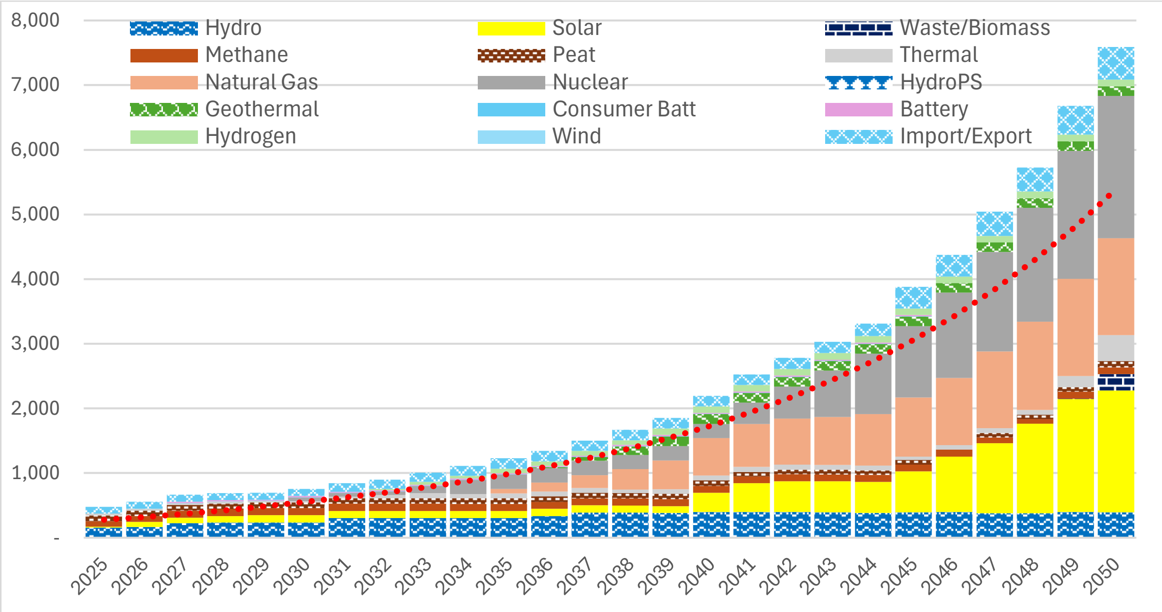


Figure 16: Electricity generation (GWh) in the alternative demand scenario: 15% annual demand growth by 2030 and 12% afterwards

- Accelerated Expansion: With a front-loaded growth rate (15% until 2030), the capacity curve rises more sharply than in the 12% scenario. By 2050, installed capacity reaches almost 8,000 MW, reflecting earlier and larger investments in multiple technologies.
- Higher Peak Demand: The dotted red line (peak demand) similarly climbs faster, but capacity additions still outpace it, maintaining a prudent reserve margin to fulfill reliability targets.
- Greater Emphasis on Firm Capacity: Owing to the more rapid short-term increase in demand, there is a sizable expansion of natural gas, nuclear, and thermal resources to guarantee dispatchable power, especially in the early-to-mid 2030s.

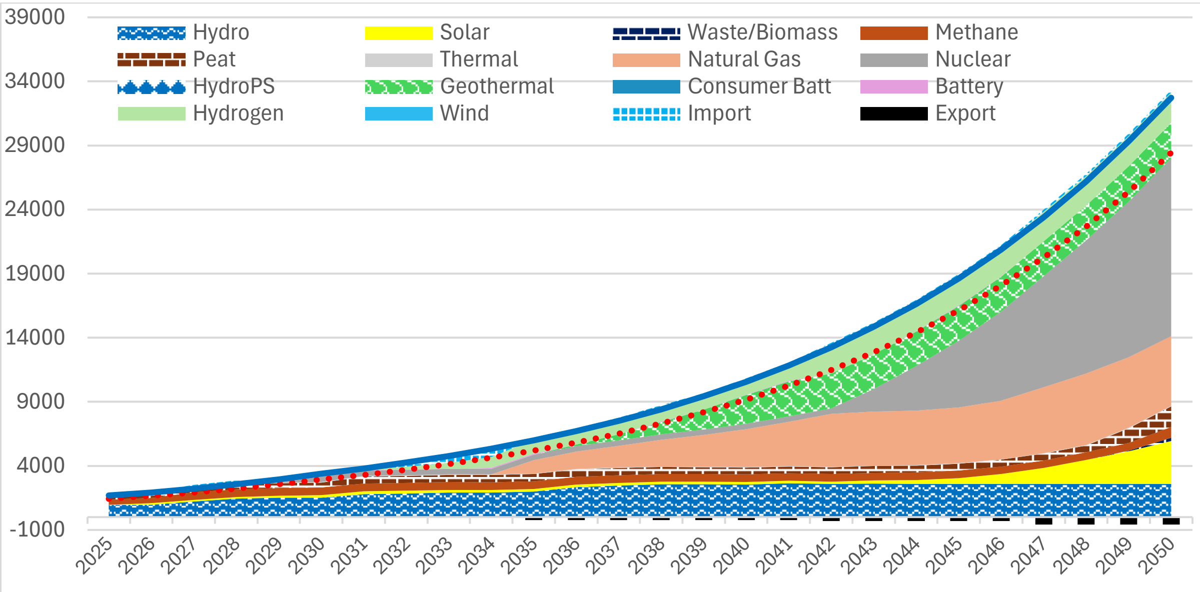


Figure 17: Electricity generation (GWh) in the alternative demand scenario: 15% annual demand growth by 2030 and 12% afterwards

By 2050, total production is in the 30,000–34,000 GWh range—substantially higher than in the purely 12% scenario. This large production base indicates capacity not only for domestic requirements but also for export possibilities if economic or regional market conditions are favorable.

Expanded Low-Carbon Technologies: Renewables (hydro, solar, wind, geothermal) continue to grow, supported by storage (batteries, hydrogen) and firm resources (natural gas, nuclear, peat). This balanced approach meets robust demand while aligning with longer-term decarbonization aspirations.

Maintaining Supply Security: The high-growth scenario prioritizes resilient, diversified generation to avoid shortages as industrialization and electrification accelerate.

Key Observations and Take-aways

- Sufficient Reserve Margins: In all higher-growth scenarios, installed capacity comfortably exceeds peak demand, indicating a planning strategy that values reliability and security of supply—albeit with the cost trade-offs of surplus capacity.
- Diverse Resource Portfolio: Hydropower remains foundational, but increasing shares of natural gas, nuclear, solar, wind, peat, and other emerging solutions demonstrate a multipronged expansion that mitigates fuel-supply risks and adapts to future policy or market shifts.
- Export Potential: As production grows well beyond local demand, cross-border trading becomes more viable, potentially contributing to economic gains if regional markets support profitable exports.
- Policy Alignment: These scenarios align with Rwanda's aspirations for universal access, industrial expansion, and climate-resilient growth, showing how higher demand growth can be met through technologically diverse and strategically timed additions.
- Grid Flexibility and Storage: The inclusion of various storage technologies (pumped hydro, battery systems, hydrogen) highlights the need to balance intermittent renewables, maintain grid frequency, and manage peak loads efficiently, especially under rapid demand increases.

Under both 12% and 15%/12% growth scenarios, Rwanda's system is modelled to remain secure and well-capacitated. The key difference is the faster build-out of dispatchable and renewable technologies to meet the near-term surge under 15% growth before settling to 12%. These expansions equip the country to handle strong demand growth and position it as a potential net exporter within the region's evolving power markets.

8.3. Supply-side Scenarios

8.3.1. Power-trade and Interconnections

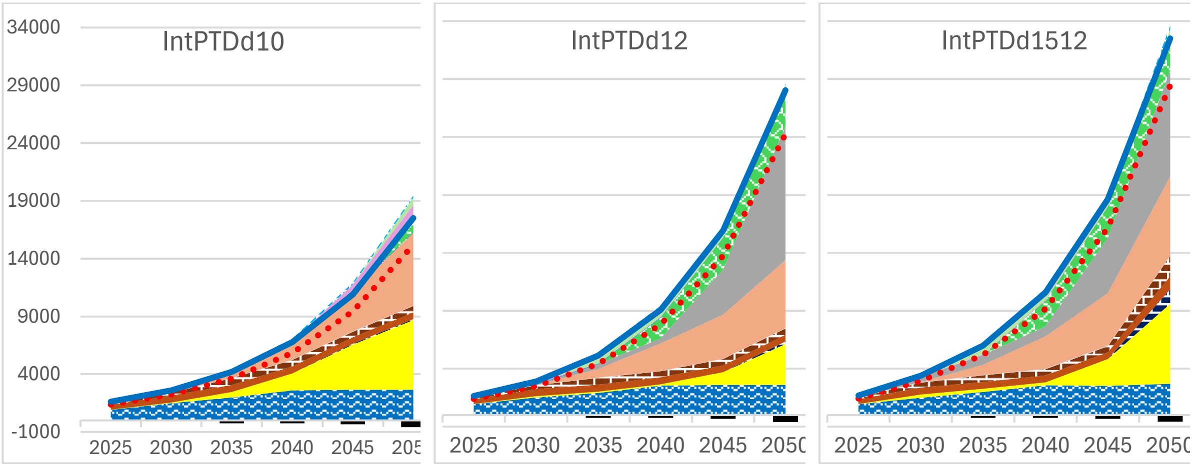


Figure 18: Electricity generation (GWh) across interconnections and power trade for the 3 demand growth scenarios

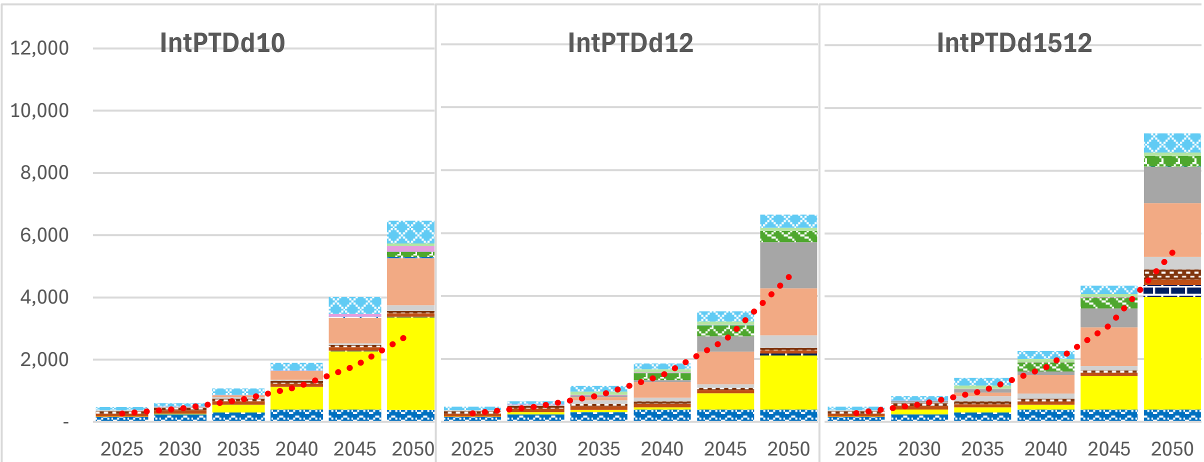


Figure 19: Installed Capacity across interconnections and power trade for the 3 demand growth scenarios

8.3.2. Domestic supply

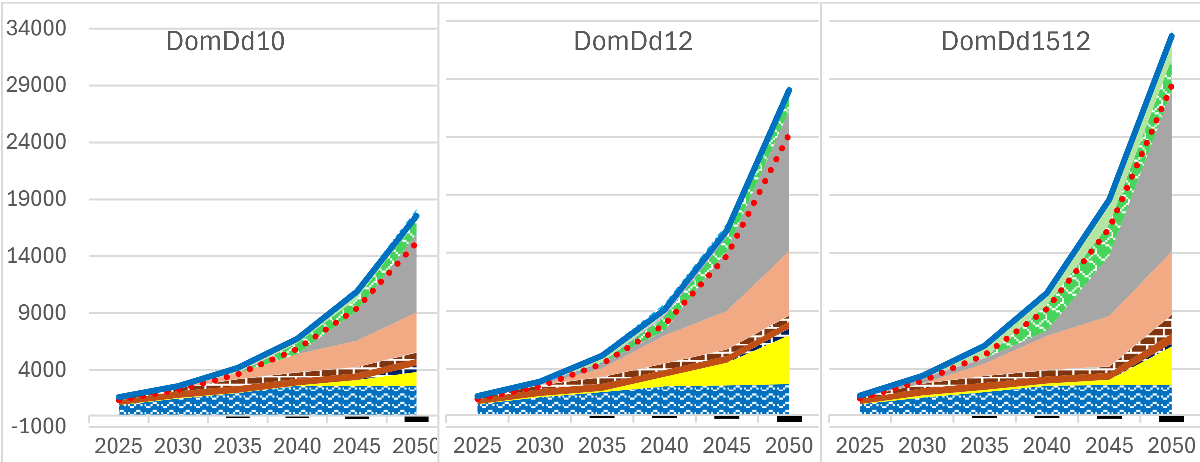


Figure 20: Electricity generation (GWh) in the strictly domestic supply case for the 3 demand growth scenarios

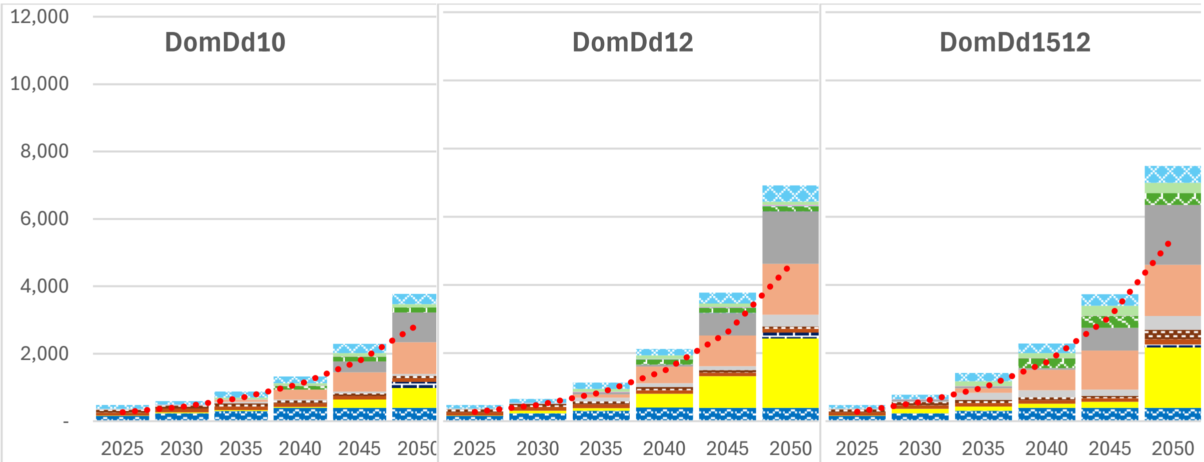


Figure 21: Installed Capacity in the strictly domestic supply case for the 3 demand growth scenarios

8.3.3. Renewable Energy Share

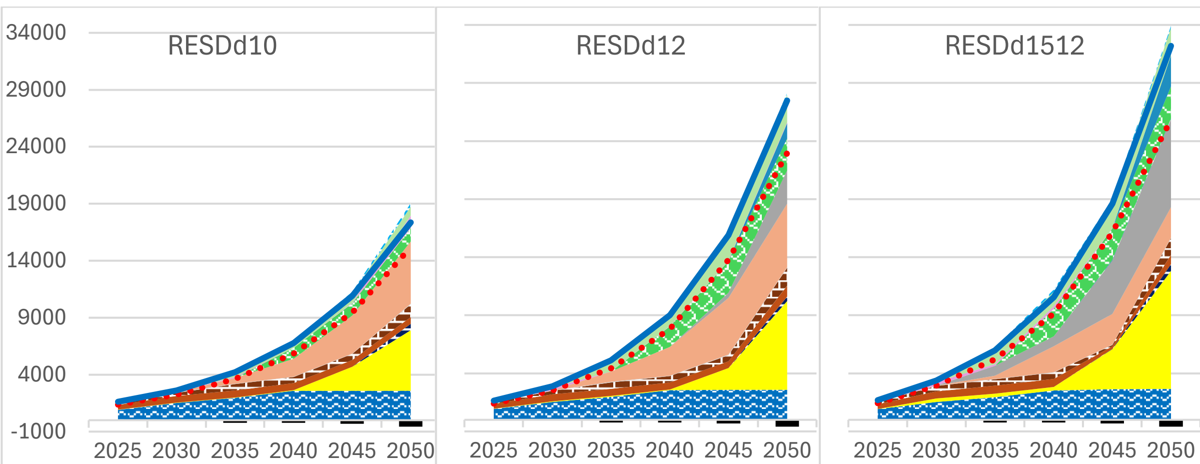


Figure 22: Electricity generation (GWh) across intensive Renewable Energy supply expansion for the 3 demand growth scenarios

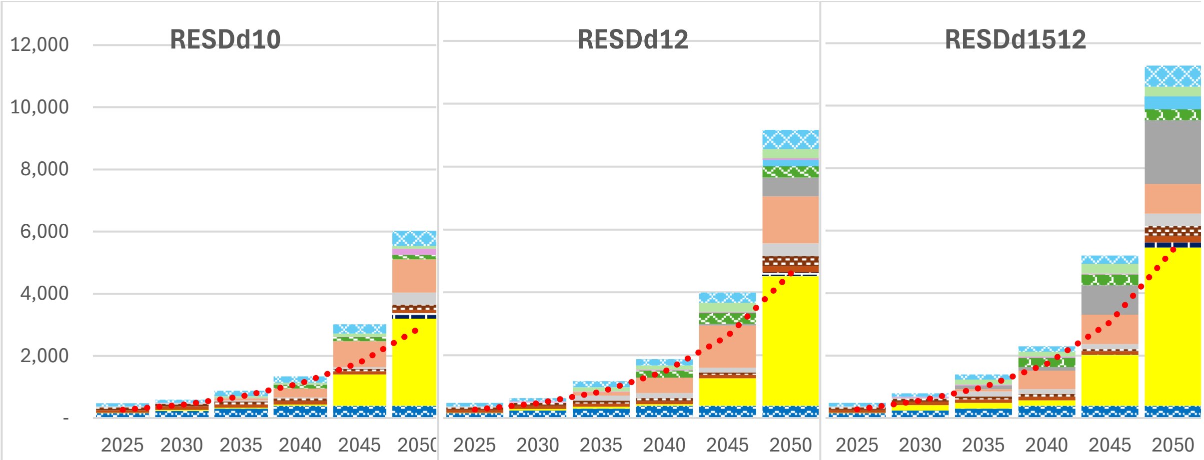


Figure 23: Installed Capacity across intensive Renewable Energy supply expansion for the 3 demand growth scenarios

8.4. Sensitivity to project implementation of key Power Plants

This sensitivity analysis is built on 2 main projects: a potential delay of RusiziIII Regional Hydro PP which is countered by increase solar PV and Hydro PS; and a strategic commitment to fastrack Nuclear SMR for power generation. This was done in 4 stages:

1. The Reference Case built around the 12 Demand and Supply Side Scenarios
2. D.Ref: All features of the reference case with a delayed RusiziIII COD from 2031 to 2033,
3. D.Ref.HPS: All features of the modified reference case with a delayed RusiziIII COD from 2031 to 2033, coupled with a commitment to pursue Nyabarongo2 downstream hydropower (Butamwa HPS, Juru HPS)
4. D.Ref.HPS.SMR: All features of the modified reference case with a delayed RusiziIII, Commitment to Pursue Nyabarongo2 downstream hydropower (Butamwa HPS, Juru HPS), and Nuclear/SMR by 2033.

A delay in RusiziIII of about 2 years would entail adding more solar PV (integrated with storage) for peak power dispatch and import capacity additions. The Least Cost scenario shift from Domestic supply in the initial state (Reference Case), to Domestic Supply with only a delayed RusiziIII, and Interconnections and Power trade in the delayed RusiziIII case and strategic commitment on Nyabarongo2 downstream hydro pumped storage (Butamwa HydroPS: 40MW; Juru HydroPS: 40MW), and Sake HPP: 10.5 MW.

Table 10: Summary comparison of scenarios under the project implementation sensitivity

Metric/Indicator		Reference Scenario (Business As Usual)			Domestic Generation			Power Trade & Interconnections			Renewables		
		Demand Δ (10%)	Demand Δ (12%)	Demand Δ (15% till 2030 & 12% after)	Demand Δ (10%)	Demand Δ (12%)	Demand Δ (15% till 2030 & 12% after)	Demand Δ (10%)	Demand Δ (12%)	Demand Δ (15% till 2030 & 12% after)	Demand Δ (10%)	Demand Δ (12%)	Demand Δ (15% till 2030 & 12% after)
Installed Capacity (MW)	2030	649	730	966	649	729	966	650	718	924	653	697	941
	2050	4104	6223	8277	4104	7125	7838	4999	7015	8528	6140	9314	11545
Total Demand (GWh)	2030	2623	2895	3385	2623	2895	3385	2627	2893	3386	2618	2893	3342
	2050	17561	28032	32710	17561	27981	32630	17562	28049	32720	17210	27643	32437
Imports (GWh)	2030	176	176	209	176	176	209	176	176	176	176	176	176
	2050	176	176	218	176	233	251	176	176	176	287	176	176
Renewable energy share (%)	2030	63%	62%	63%	63%	62%	63%	63%	63%	63%	62%	64%	63%
	2050	37%	35%	33%	37%	34%	36%	48%	35%	37%	61%	59%	61%
Exports (GWh)	2030	-46	-46	-22	-46	-46	-22	-46	-46	-36	-46	-46	-46
	2050	-579	-579	-579	-579	-579	-579	-595	-1367	-1358	-579	-579	-579
Total Discounted Cost of Energy Supply (USD M)	2050	5055	6202	7156	5055	6259	7078	5028	6041	6876	5156	6352	7283
Expansion scenario costs relative to the Ref. scenario and the least cost scenario (USD M)	Rfr	N/A	N/A	N/A	N/A	57	-77	-27	-161	-280	101	150	128
	LC	27	161	280	27	218	202	0	0	0	128	311	408
Peak Demand (MW)	2030	428	477	559	428	477	559	428	477	559	428	477	559
	2050	2881	4602	5393	2881	4602	5393	2881	4602	5393	2881	4602	5393

8.4.1. Least Cost Scenario

8.4.1.a Installed Power Generating Capacity in the Short to Medium Term: 2025 – 2031

Figure 28 below shows the total domestic installed capacity over the next 6 years.

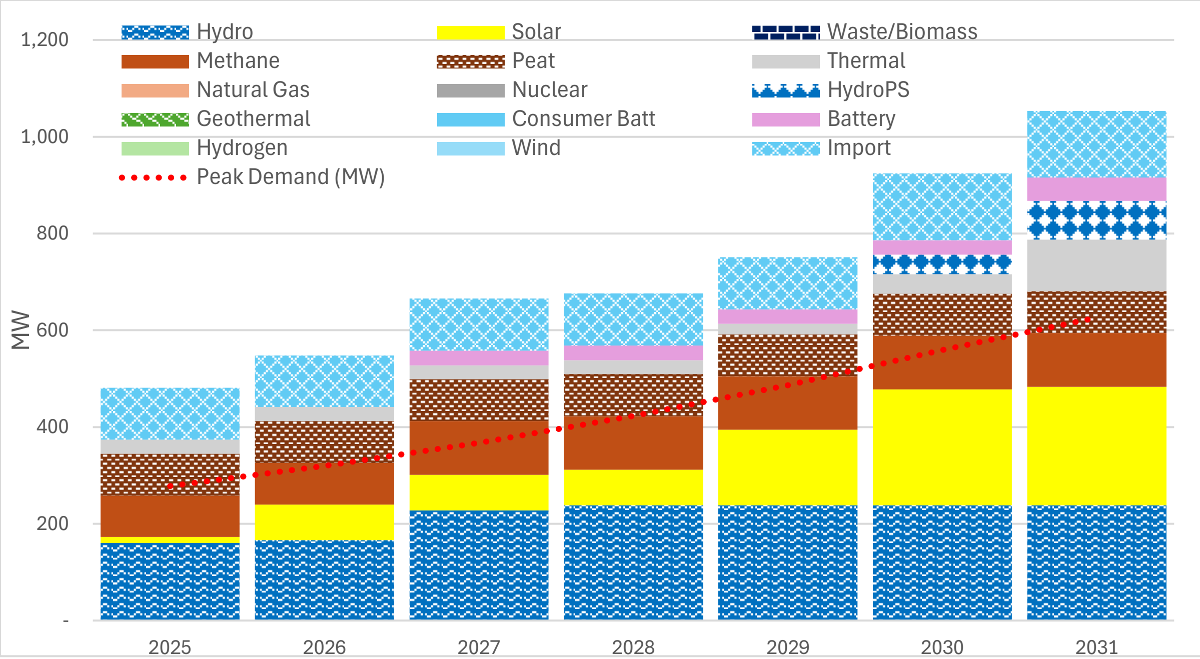


Figure 24: Total domestic installed capacity (MW) and peak demand in the near term 2025-2031

For the installed capacity in the short term 2025-2031 to be enough to satisfy the annual growing demand and reserve margin requirements in the high growth scenario, the following capacity additions are needed in addition to optimising existing power plants:

- Nyabarongo-2 hydro power plant.
- Rusizi-3 Regional Hydropower plant.
- 100 MW of Solar PV capacity integrated with storage (Nyabarongo2 Solar PV).
- Scaling up existing methane-fire power plants by at least 25 MW
- Rukarara VI hydropower plant.
- Design and develop Rwanda solar park with potential for scale up to 128 MW.
- Increase emergence/standby thermal ramp up capacity to 41 MW
- Strengthen power trade N-1 contingency with additional imports of 50 MW
- Undertake technical feasibility studies to increase emergence/standby capacity to grow proportionately to the system growth.
  This might necessitate upgrading of Jabana1 from 7.8 MW to 30 MW is required to maintain a higher reserve margins 15%, and high grid frequency response, especially in the event of extreme seasonal weather variations (hydrological and sunshine).
- Undertake feasibility studies for:
  - natural gas pipeline and natural gas fired power plants.
  - battery energy storages systems.

Total installed capacity of thermal (diesel) powered plants remains at 28.80 MW 24. However, upgrading Jabana1 from 7.8 MW to 30 MW is required to maintain a higher reserve margins 15%, especially in the event of extreme seasonal variations.

Excess capacity of about 40 MW (off-peak and shoulder hours), and in addition to solar PV capacity additions necessitates storage options for peak shifting (Hydro PS and BESS) or for export, adding to domestic demand and significantly increase potential company earnings.

8.4.1.b Installed Power Generating Capacity in the Longer Horizon: 2032 – 2050

Figure 25 shows the evolution of total installed capacity of generation supply technologies on the Rwandan grid.

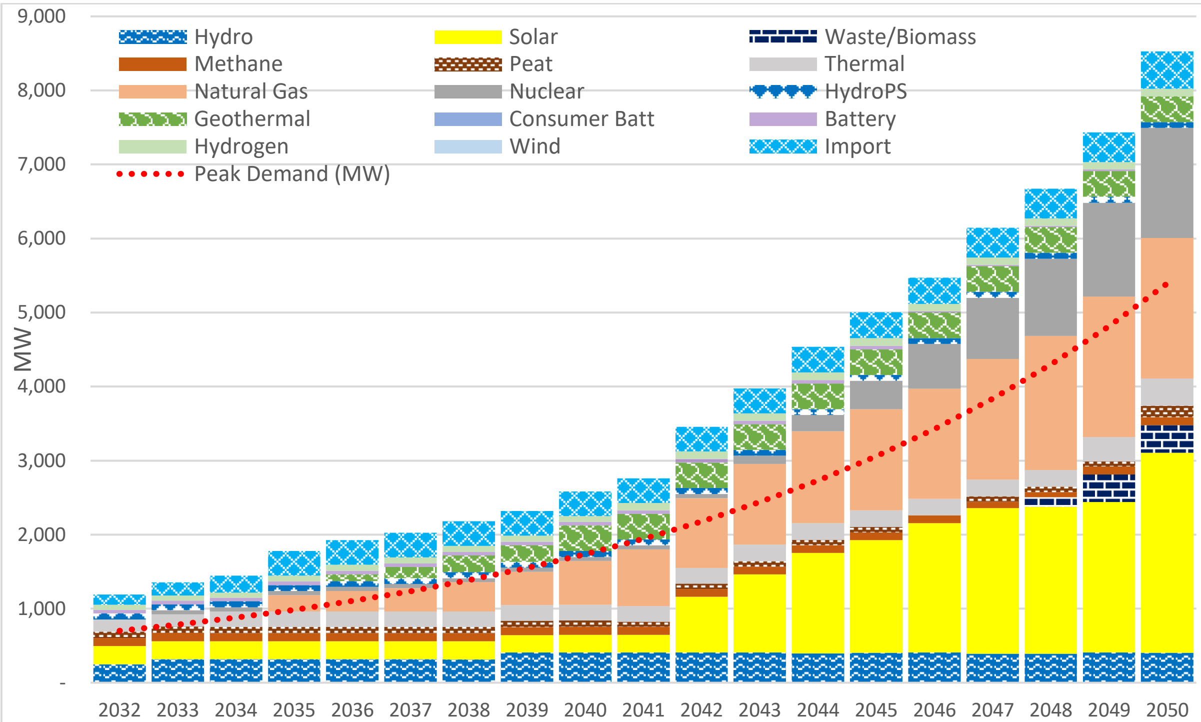


Figure 25: Total Installed Capacity (MW) and peak demand in the longer term 2032 - 2050.

New supply technologies are added onto the grid to satisfy demand. These include natural gas, utility-scale solar PV, consumer battery storages with projected required installed capacity as outlined below:

* 406 MW of Hydro Power.
* 2,701 MW of Solar PV embedded with storage.
* 372 MW of Waste to Power.
* 105 MW of Methane-fired power plant.
* 156 MW of peat to power plant.
* 369 MW of thermal Diesel/HFO generators.
* 1900 MW of natural gas installed capacity.
* 1485 MW of Nuclear-SMR.

24 Jabana I and II diesel-power plants.

* 80 MW of Hydro PS.
* 350 MW of Generic Geothermal.
* 100 MW of Green Hydrogen.
* 48 MW in Grid BESS.
* 505 MW in power traded capacity.

The total installed capacity rise consistently above the red line (peak demand), indicating that planned additions provide a comfortable reserve margin over the entire period. The gap widens substantially from the early 2040s onward, suggesting a proactive strategy to meet future consumption and ensure supply security.

Hydropower remains a core component, but newer technologies begin to occupy an increasing share of the total installed capacity as the horizon extends. This reflects Rwanda's aim to leverage its existing hydro resources while gradually diversifying to reduce dependency on a single energy source.

Large additions of natural gas generation appear from the mid-2030s onward, becoming a significant contributor to overall capacity. Later, nuclear emerges toward the 2040s, expanding to a notable share by 2050. These two firms, low-emission (or lower-emission) sources help meet rising demand reliably, complementing renewables.

Solar and various new technologies (hydrogen, wind, geothermal, waste/biomass) steadily gain importance, especially in the 2035s. Their presence underscores a deliberate approach to integrate cleaner, more flexible systems (e.g., HydroPS, battery storage) that support grid stability and address variability from renewables like solar and wind.

A visible share of import capacity is maintained or grows over time, suggesting that cross-border electricity trade will remain an important strategy—either for economic dispatch or to balance local supply fluctuations, in line with broader regional market opportunities.

By 2050, the total installed capacity significantly exceeds peak demand, aligning with policy objectives to ensure resilience against hydrological variability, demand surges, and unforeseen outages. While this planning margin adds reliability, it also highlights the need to manage potential cost implications of underutilized capacity.

The increasing share of renewable and lower-carbon technologies (solar, wind, geothermal, hydrogen, nuclear) aligns with long-term climate goals and reduces exposure to fuel price volatility. Meanwhile, gas and strategic imports remain important for ensuring dispatchable power and bridging seasonal gaps, especially in a high-demand growth scenario.

8.4.1.c Electricity Production & Demand:

Figure 30 and table 11 provide a 5-year time step of the annual production profiles of each technology type during this planning horizon.

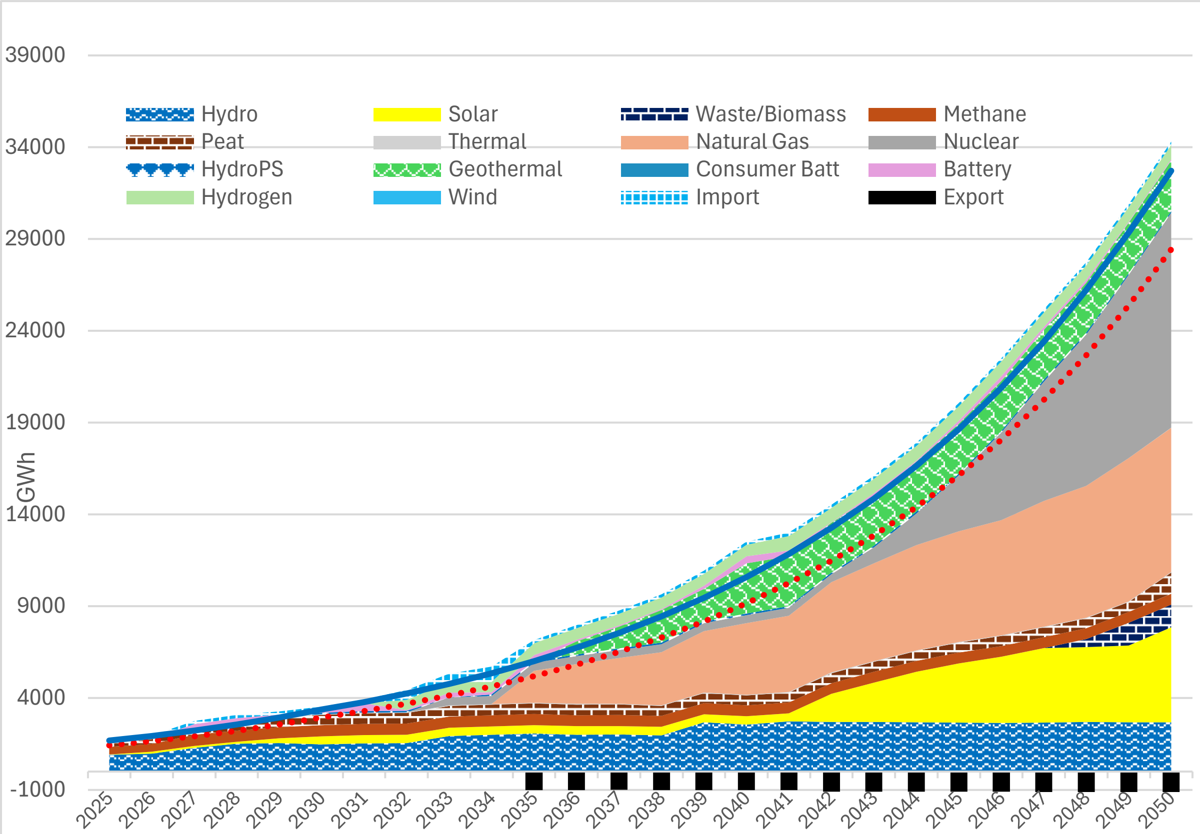


Figure 26: Production per Technology Type (GWh)

Growing Reliance on Hydropower, Then Diversification: Hydro remains the foundational resource across the planning horizon. However, as total production expands, other sources (natural gas, nuclear, peat, and various renewables) take up a larger share, reflecting Rwanda's shift toward a more diversified and resilient energy mix.

Emerging and Advanced Technologies: Over time, the chart shows notable contributions from nuclear, natural gas, and renewables (solar, wind, geothermal, hydrogen) in the 2040s and beyond. This indicates growing technology diversity to meet surging demand and aligns with broader goals of reliability and decarbonization.

Export Potential: The black bar segments toward the top represents exported electricity. As domestic production increasingly exceeds local demand, exports become a more prominent slice of total output. This supports the national objective of enhancing regional trade and earning revenue from surplus capacity.

Overall, the chart illustrates Rwanda's pathway toward a robust, multi-resource generation portfolio by 2050—anchored in hydropower yet increasingly supported by a range of complementary technologies. This trajectory positions Rwanda to meet growing domestic demand while capitalizing on export opportunities in the regional electricity market.

It is clear that hydro dominance persists in the short to medium term planning horizons. Peat production also increases to satisfy the domestic demand. In addition, thermal requirements are minimized. This is due to the least-cost selection of supply from imports and other available cheaper and renewable energy generation options within this time period. Production from nuclear begins and contributes significantly after 2035 as installed capacity requirements increases.

Table 11: Production (GWh) per Technology Type

Year	2025	2030	2035	2040	2045	2050
Domestic Production	1562.4	3357.5	6980.7	12357.0	19895.4	34130.6
Hydro	916.3	1,477.6	2,075.0	2,562.1	2,669.4	2,676.7
Solar	15.0	447.9	458.8	446.2	3,222.6	5,180.6
Waste/Biomass	-	-	-	-	-	1,238.3
Methane	414.5	600.5	600.5	600.5	585.9	585.9
Peat	177.8	558.1	577.3	542.0	542.0	1,159.3
Thermal	38.8	38.8	38.8	38.8	38.8	38.8
Natural Gas	-	-	1,734.5	3,900.4	6,031.6	7,839.2
Nuclear	-	-	433.6	433.6	3,035.3	11,707.7
HydroPS	-	80.6	96.0	90.3	92.4	92.7
Geothermal	-	-	-	2,720.0	2,720.0	2,759.4
Consumer Batt	-	-	-	-	-	-
Battery	-	154.2	335.5	392.4	168.9	63.6
Hydrogen	-	-	630.7	630.7	788.4	788.4
Wind	-	-	-	-	-	-
Power trade	130.6	140.1	-823.9	-831.2	-918.8	-1181.6
Import	176.2	176.2	176.2	176.2	176.2	176.2
Export	(45.6)	(36.1)	(1,000.1)	(1,007.4)	(1,095.0)	(1,357.8)
Total Supply	1693.0	3497.6	6156.8	11525.8	18976.6	32949.0
Grid Losses	263.3	437.7	809.9	1443.9	2513.1	4283.1
Transmission Losses	52.2	95.3	198.3	357.7	590.7	994.0
Distribution Losses	211.2	342.3	611.6	1,086.2	1,922.5	3,289.1
Final Demand	1428.3	2947.9	5195.2	9155.8	16135.6	28436.4
Total Demand	1691.6	3385.6	6005.1	10599.7	18648.7	32719.5

8.4.2. Project Implementation Effects by 2030

Solar PV + BESS raises from 124 MW (addition of 144 MW by 2030) to 268 MW to compensate for a delay in RusiziIII and 240 MW when a delay in RusiziIII goes with the strategic decision to carry on with Hydro PS:

- Standalone BESS capacity increases from 15 MW to 30 MW.
- Imports capacity raises from 124 MW to 138MW and to 166 MW.
- Thermal Power Generation installed capacity also increases with an addition 20 MW from the current 21 MW to 41 MW.

In light of these sensitivities, Nuclear SMR is also proposed to be possibly fast-tracked to 3 years early from initial COD of the 1st unit (55 MW) in the year 2033 to 2030.

8.4.3. Financial Implications

The delay of RusiziIII and a strategic decision to carry on with HydroPS costs the following per scenario and state:

Relative to the initial state: an average USD 113 M from in overall discounted systems cost across scenarios (till 2050), with a minimum of USD 75 M in the scenario of Power Trade and interconnection with high demand growth (15%&12%), and a maximum of USD 304 M in the alternative high demand growth (15%&12%).

Relative to only a delay of Rusizi3, an average USD 175 M in discounted systems cost across high growth scenarios, with a minimum of USD 153 M in both the scenario of scenarios of Domestic Supply and Power Trade and interconnection with high demand growth

(15%&12%), and a maximum of USD 223 M in the Renewables scenario with high demand growth (15%&12%).

The long-term financial implications are presented in Figure 27 below. USD M 1,726 is required to fund generation expansion investments by 2031. This includes the ongoing Nyabarongo2 multipurpose dam and candidate projects that are still in planning/project development. Over the same horizon, USD M 1,600 is required in system fixed costs, and USD M 299 in system variable costs.

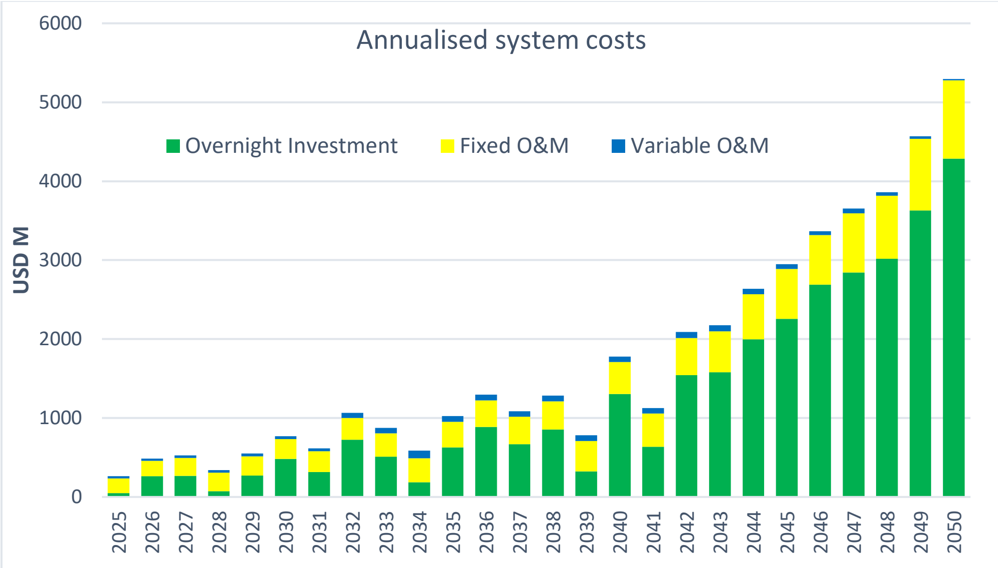


Figure 27: Annualised investment costs

This would set the Rwanda power sector to a trajectory of declining system costs per unit of energy, largely driven by loss reduction, economies of scale arising from unit optimisation with increasing system demand, and system maturity ultimately prioritizing on-boarding of least cost generation options.

8.5. Synthesis of studied scenarios

Consistent with the least cost combination in the strategic national case Domestic demand growth with 15% annual demand growth to 2030 and 12% afterwards, annual installed capacity additions per technology are shown in Table 12 below.

In addition to committer projects presented in table 6, below is the representation of technology specific additions in line with the least cost scenario (power trade in the 3rd alternative demand growth scenario).

Table 12: Annual Added Capacity (MW) per Technology Type

Year	Power Plant(S)	Technology added	Installed Capacity (MW)
2025	Additional Imports	Imports	20
2026	Generic SolarPV+BESS	Solar+BESS	61
2027	Generic BESS	BESS	30
2029	Generic SolarPV+BESS	Solar+BESS	23
2030	Generic SolarPV+BESS-expansion	Solar+BESS	84
	Generic New Diesel	HFO/Diesel	20
	Generic HydroPS	HydroPS	40
	Additional Imports	Imports	30
2031	Generic SolarPV+BESS-expansion	Solar+BESS	6
	New Diesel-expansion	HFO/Diesel	66
	Generic HydroPS	HydroPS	40
	Generic BESS-expansion	BESS	18
2032	Sake Hydro Power Plant	Hydro	10
	Generic New Diesel	HFO/Diesel	58

Year	Power Plant(S)	Technology added	Installed Capacity (MW)
	Generic Green Hydrogen	Hydrogen	70
2033	Nuclear-SMR-expansion	Nuclear	55
	Additional Imports	Imports	41
2034	New Diesel-expansion	HFO/Diesel	64
	Additional Imports	Imports	49
2035	Generic Green Hydrogen-expansion	Hydrogen	10
	Generic Natural gas -CC PP	Natural gas	220
	Additional Imports	Imports	104
2036	Generic Natural gas -CC PP-expansion	Natural gas	55
	Generic Geothermal PP	Geothermal	90
2037	Generic Natural gas -CC PP-expansion	Natural gas	40
	Generic Geothermal PP-expansion	Geothermal	60
2038	Generic Natural gas -CC PP	Natural gas	80
	Generic Geothermal PP-expansion	Geothermal	75
2039	Generic Natural gas -CC PP	Natural gas	55
2040	Generic Natural gas -CC PP	Natural gas	140
	Generic Geothermal PP	Geothermal	120
2041	Generic Natural gas -CC PP	Natural gas	175
	Kivuwatt Rehabilitation	Methane gas	26
	Generic Green Hydrogen	Hydrogen	20
2042	Generic SolarPV+BESS-expansion	Solar+BESS	519
	Generic Natural gas -OC PP-expansion	Natural gas	180
2043	Generic SolarPV+BESS	Solar+BESS	304
	Generic Natural gas -OC PP-expansion	Natural gas	145
	Nuclear-SMR-expansion	Nuclear	55
2044	Nuclear-SMR-expansion	Nuclear	110
	Generic Natural gas -OC PP-expansion	Natural gas	150
	Generic SolarPV+BESS-expansion	Solar+BESS	300
	Additional Imports	Imports	16
2045	Nuclear-SMR-expansion	Nuclear	165
	Generic Natural gas -OC PP-expansion	Natural gas	125
	Generic Solar PV+BESS-expansion	Solar+BESS	225
2046	Nuclear-SMR-expansion	Nuclear	220
	Generic Solar PV+BESS	Solar+BESS	225
	Generic Natural gas -OC PP-expansion	Natural gas	120
2047	Hakan HQ - Rehabilitation	Peat	72
	Generic Solar PV+BESS-expansion	Solar+BESS	225
	Generic Natural gas -OC PP-expansion	Natural gas	145
	Nuclear-SMR	Nuclear	220
2048	Generic Solar PV+BESS	Solar+BESS	16
	Additional Imports	Imports	53
	SPLK Rehabilitation	Methane gas	56
	Generic Natural gas -OC PP-expansion	Natural gas	180
	Nuclear-SMR-expansion	Nuclear	220
	Generic Waste/Biomass to Power	Waste/Biomass	130
2049	Generic Solar PV+BESS	Solar+BESS	49
	Generic New Diesel	HFO/Diesel	101
	Generic Solar PV+BESS-expansion	Solar+BESS	49
	Nuclear-SMR-expansion	Nuclear	220
	Generic Waste/Biomass to Power	Waste/Biomass	242
	Generic Geothermal PP-expansion	Geothermal	5
	Generic New Peat PP	Peat	83
2050	Generic Solar PV+BESS	Solar+BESS	667
	Additional Imports	Import	102
	Nuclear-SMR-expansion	Nuclear	220
	Generic New Peat PP	Peat	83
	Generic New Diesel	HFO/Diesel	43

8.6. Renewable Energy Share (RES) in Total Electricity Production

Figure 28 below shows the renewable energy share (RES) in power production throughout the planning horizon. The ESSP targets set were met during this time horizon.

In the short-term higher levels of peat production decrease RES contribution. However, in the longer-term performance improves this performance as more hydro is added and dispatched within the system. Compliance with this policy target requires further monitoring to ensure that Rwanda remains committed to decarbonizing power production.

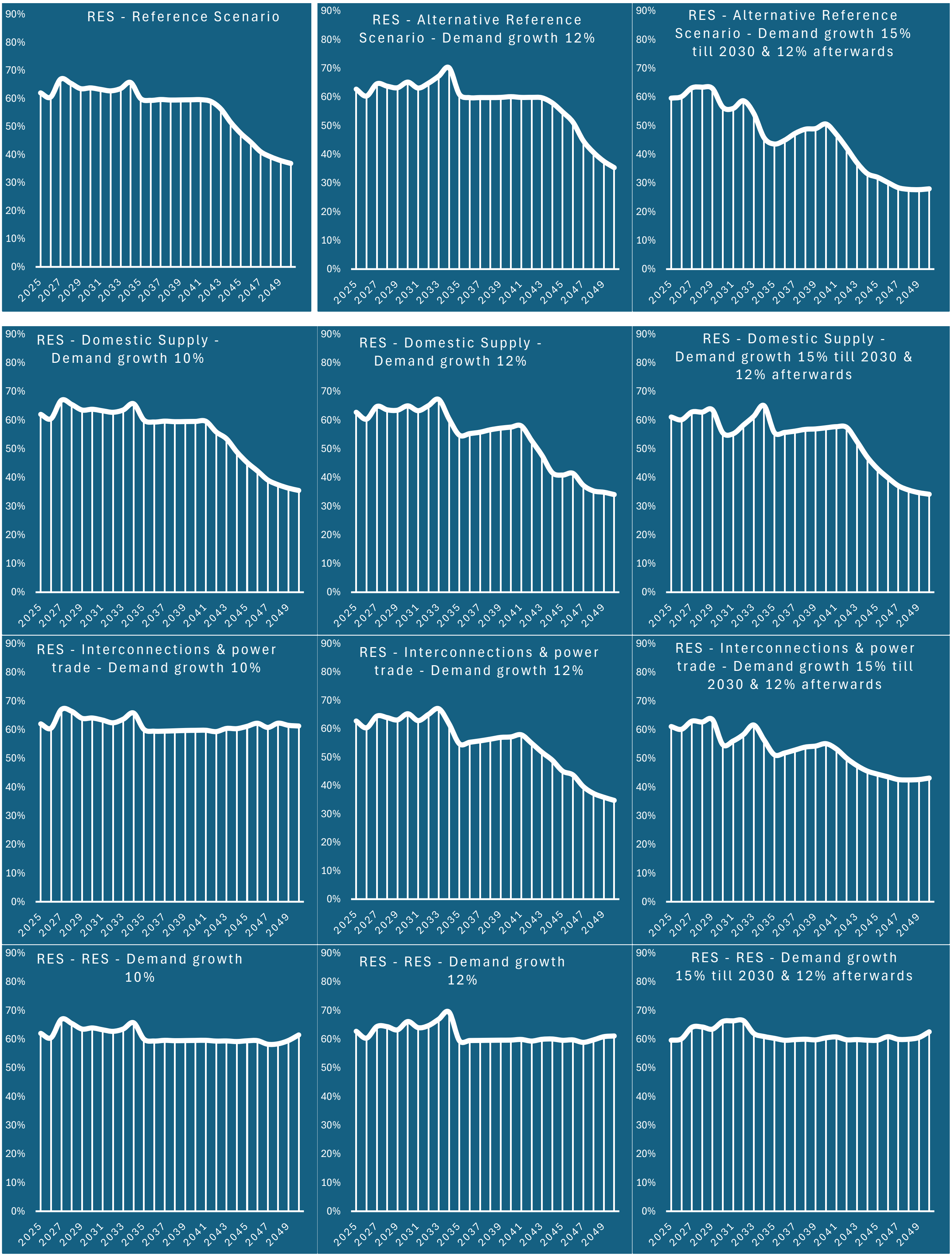


Figure 28: RES in power generation mix (%) across studied scenarios.

9. Climate Change & Impact on Hydropower Production[25]

9.1. Introduction

Climate change can threaten the viability of future hydropower development and operations. To understand the potential risks and vulnerabilities of hydropower plants to climate change the below modelling framework.

Hydropower can help achieve electrification goals while minimizing greenhouse emissions. Additionally, hydropower can help balance intermittent renewables (e.g., solar and wind) to meet the country's growing electricity needs. Unfortunately, climate change can threaten the viability of future hydropower development and operations. Given the limited research on climate-induced risks to hydropower plants in Sub Saharan Africa (SSA), this work aims at increasing the knowledge and understanding about the potential effects that climate change is likely to pose on hydropower in Rwanda, given the current and future predicted hydro dominance of the grid.

A flexible data requirement climate risk and vulnerability framework for hydropower assessment under climate change is applied to Rwanda. The initial analysis for Rwanda includes seven cascading hydropower plants. *table 13* presents the list of the power plants and their main characteristics (information provided by the Rwanda Energy Group - REG). These power plants include the Rusumo Regional Hydropower Project (80 MW)[26], which began dispatching operations in the end of September 2023, and Nyundo Hydropower Plant (4.5 MW) which is scheduled for commissioning in 2027/8.

Figure 29 presents a map with the eight power plants and their corresponding sub-basins which have been calculated using ArcGIS and its hydrology tools.

Table 13: Power Plant Characteristics

Power Plant	Type	Installed Capacity (MW)	Effective Height (m)	Live Storage Capacity (MCM)	Design Flow (m3/s)	Status	Construction Year
Nyabarongo I	Impoundment	28	44.5	13.37	54	Operating	2014
Ntaruka	Impoundment	11.25	169	201	12	Operating	1957
Mukungwa I	Impoundment	12	65	89.6	14	Operating	1988
Rwaza	Run-of-river	2.6	-	-	12	Operating	2018
Mukungwa II	Run-of-river	3.6	6	0.9	13.6	Operating	2013
Nyundo	Run-of-river	4.5	-	-	13	Planned	2027/2028

25 Study done by Ms Ana Caceres, Ph.D. Candidate, Department of Engineering and Public Policy Department of Civil and Environmental Engineering, Carnegie Mellon University under the E-Guide Project. Data source: REG.

26 The total installed capacity here is reported for the regional HPP, to ensure accurate modelling for water availability and comparison of results with the existing Rusumo HPP feasibility study, which is publically available. However, Rwanda's share is 26.7 MW as reported in earlier chapters in this report.

Power Plant	Type	Installed Capacity (MW)	Effective Height (m)	Live Storage Capacity (MCM)	Design Flow (m3/s)	Status	Construction Year
Nyabarongo II	Impoundment	43.5	49	786.9	99.9	Planned	2027
Rusumo Regional HPP	Impoundment Run-of-river	80	15.3	184.5	116.9	Operating	2023

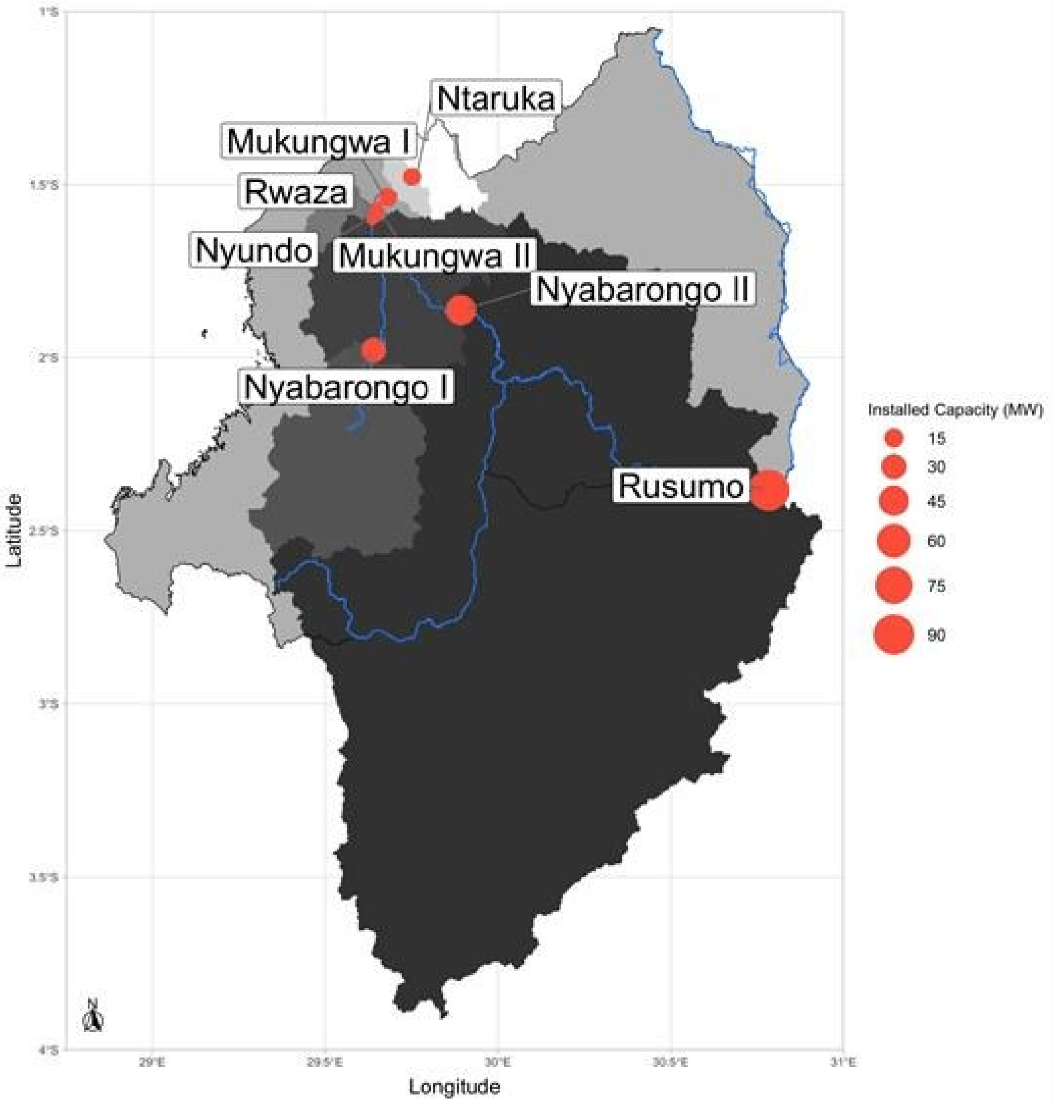


Figure 29: HPPs in Rwanda under analysis (different Climate Models and Climate Scenarios)

Climate projections and historical experiments were obtained from the NASA Earth Exchange Global Daily Downscaled Projections (NEX-GDDP) dataset for 21 General Circulation Models (GCMs). Each GCM was run under two Representative Concentration Pathways (RCPs): RCP 4.5 and RCP 8.5. These RCPs—standardized greenhouse gas emission scenarios developed by the Intergovernmental Panel on Climate Change—represent different potential climate futures.

RCP 4.5 is a 'stabilization' scenario in which greenhouse gas concentrations peak around 2040 and then decline, implying moderate climate change.

RCP 8.5 is a 'business-as-usual' scenario in which emissions continue to rise throughout the century, representing a high-end climate change pathway.

By analyzing both scenarios, a realistic range of future conditions is captured—one where global efforts moderately curb emission and one with continued emissions growth. This breadth of possibilities helps identify potential climatic impacts on each power plant's water availability, enabling more robust planning and risk management for Rwanda's hydropower fleet.

To ensure credible model outputs, the climate simulations are calibrated against the GRUN dataset, which reconstructs global runoff from 1902 to 2014. This step helps align the modeled hydrological patterns (e.g., streamflow and rainfall) with observed historical data, thereby increasing confidence in the projections of future hydropower generation under varying climate scenarios.

Table 14: General Circulation Models (GCM) obtained from NASA's NEX-GDDP dataset and Used for Streamflow analysis

Global Climate Models
INCM4.0
BCG-CSM1-1
NorESM1-M
MRI-CGCM3
MPI-ESM-MR
MPI-ESM-LR
MIROC5
MIROC-ESM
MIROC-ESM-CHEM
IPSL-CM5A-MR
IPSL-CM5A-LR
GFDL-ESM2M
GFDL-ESM2G
GFDL-CM3
CanESM2
CSIRO-Mk3-6-0
CNRM-CM5
CESM1-BGC
CCSM4
BNU-ESM
ACCESS1-0

To generate projections of future streamflow and hydropower available capacity under different climate models and climate scenarios, a water balance model was used[27]. The model consists of a water balance hydrological model paired with a hydropower operations model. The water balance equation in the model is based on the following:

27 The main appeal of the model is that it does not require using computationally intensive hydrological models with high data requirements and could therefore be applied to regions of the world with limited data, like Rwanda

$$Qt = St{-}1 + Pt - AETt - St$$

Equation 5: Water-Balance Equation

Where: Q_t is the runoff generated at month t.

S_{t-1} is the previous month's soil moisture storage component.

P_t is the precipitation at month t.

AET_t is the actual evapotranspiration at month t.

S_t is that month's soil moisture storage component.

The water balance model is calibrated using the shuffled complex evolution (SCE) algorithm, which is widely used in hydrological applications.

Additionally, the model has been coupled with a reservoir operations model for hydropower plants with large storage capabilities. In the case of Rwanda, the three power plants[28] with storage capabilities larger than one-month worth of supply were analyzed as reservoir power plants. These power plants were Mukungwa I, Ntaruka, and Nyabarongo II.

9.2. Rwanda's Climate Forecast

Using the climate variables obtained from the NEX-GDDP dataset, it is possible to characterize future climate for the six sub-basins corresponding to the eight hydropower plants in the analysis (precipitation, maximum temperature, minimum temperature and potential evapotranspiration).

Figures 30 - 36 show the average monthly precipitation for each of the sub-basins. Rwaza-Muko and Mukungwa II power plants are close to each other so for the analysis they are considered as one sub-basin.

The average monthly precipitation for the historical period ranges from 1130 mm in the Rusumo basin to 1290 mm for Nyundo and the Rwaza-Muko/Mukungwa II basins.

Throughout the century, the multi-model mean of precipitation increases for all basins. By the end of the century precipitation increases on average between 7.8%-8.9% for RCP 4.5, and 17.8%-22.2% for RCP 8.5.

28 The reservoir adjacent to the Mukungwa I power plant (Lake Ruhondo) would be able to supply 2.5 times the monthly design flow of the power plant if no inflows were reported. Likewise, the adjacent reservoir to the Ntaruka power plant (Lake Ruhondo & Lake Burera) could supply 6.5 times the monthly design flow with no inflows. Finally, the reservoir adjacent to Nyabarongo II would be able to supply 3 times the monthly streamflow for the power plant when full.

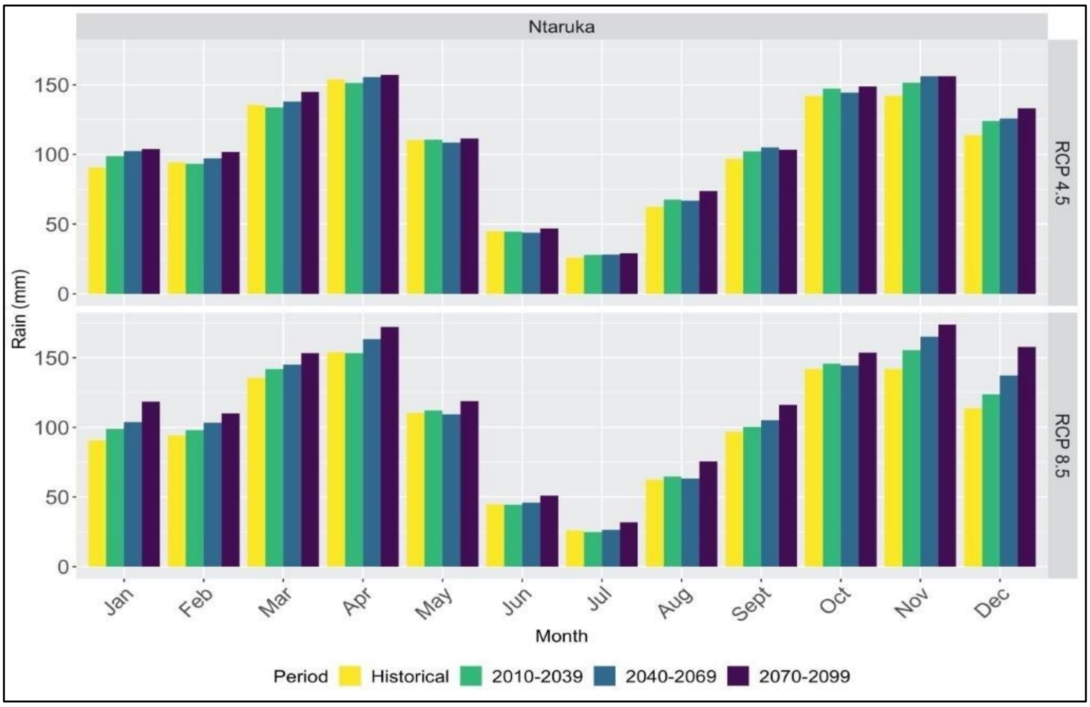


Figure 30: Average Multi-Model Precipitation (mm) for the Ntaruka Sub-basin.

The historical annual precipitation for the basin was 1210 mm. By the end of the century precipitation increases to 1310 mm for RCP 4.5 and 1430 mm for RCP 8.5.

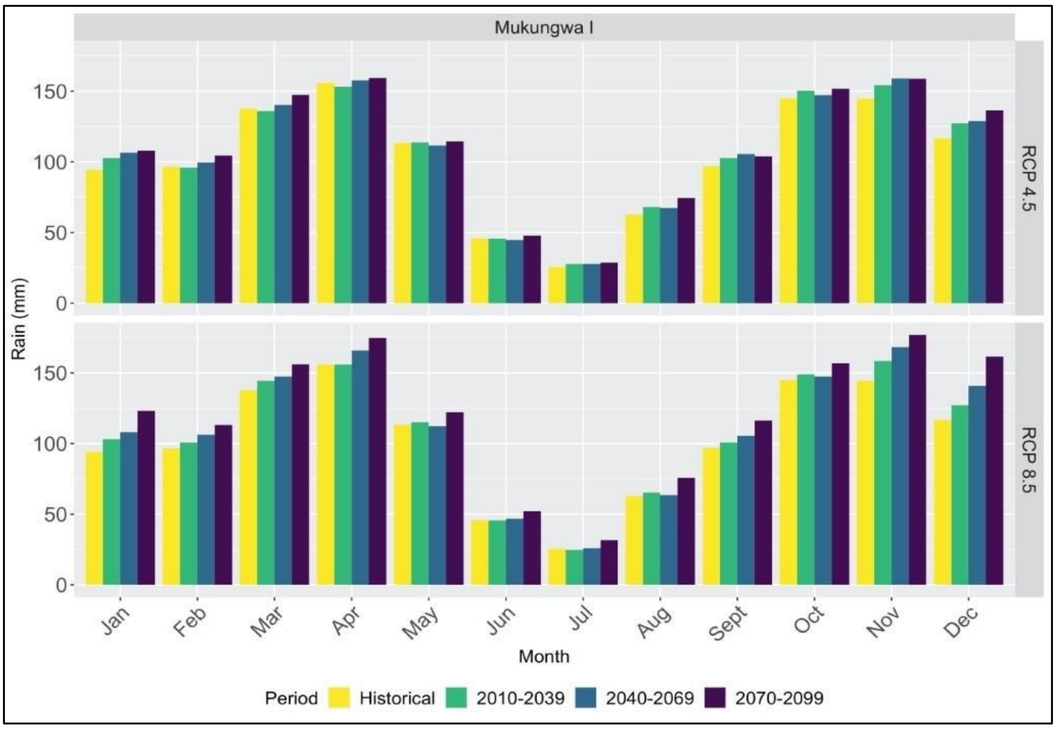


Figure 31: Average Multi-Model Precipitation (mm) for the Mukungwa I Sub-basin.

The historical annual precipitation for the basin was 1230 mm. By the end of the century precipitation increases to 1340 mm for RCP 4.5 and 1460 mm for RCP 8.5.

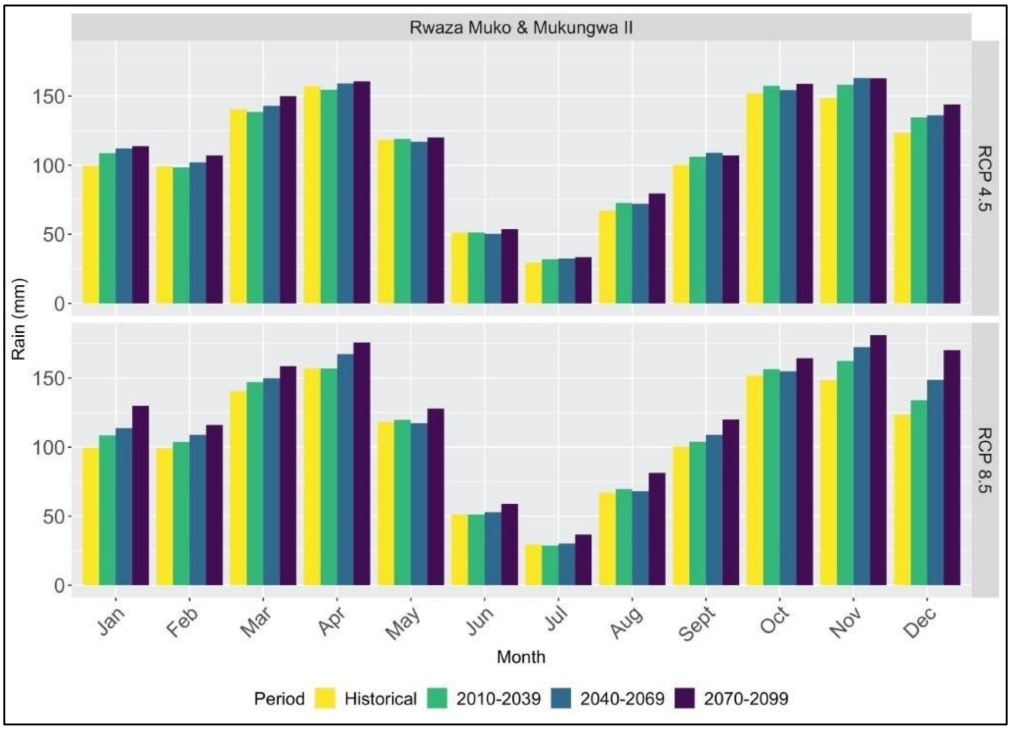


Figure 32: Average Multi-Model Precipitation (mm) for the Rwaza-Muko/Mukungwa II Sub-basin.

The historical annual precipitation for the basin was 1290 mm. By the end of the century precipitation increases to 1390 mm for RCP 4.5 and 1520 mm for RCP 8.5.

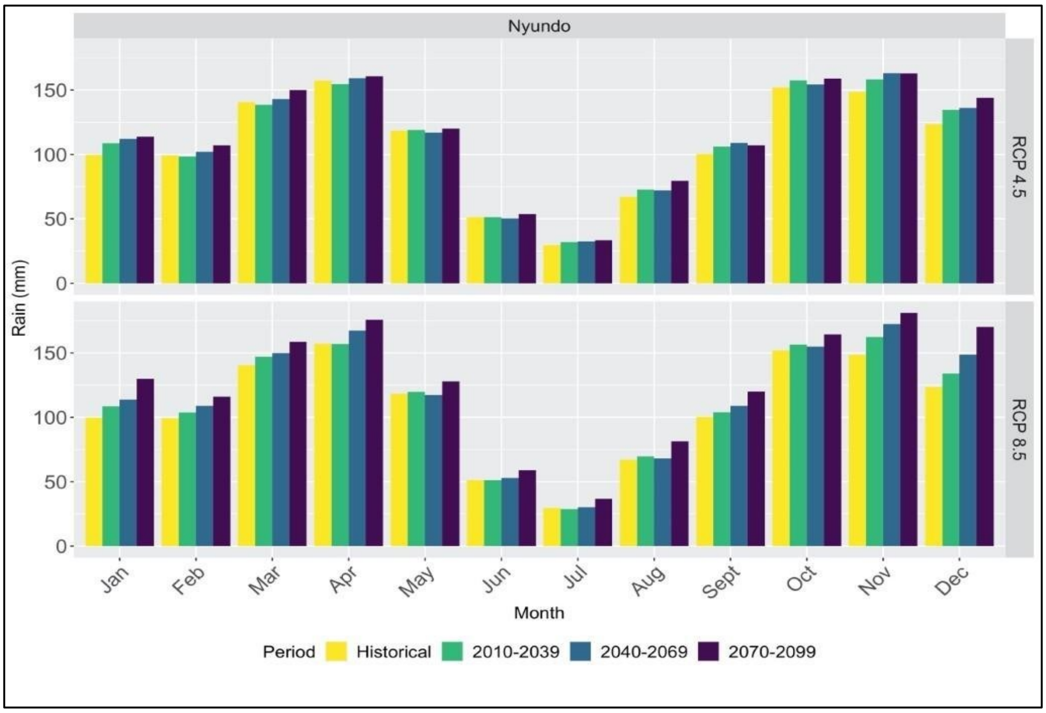


Figure 33: Average Multi-Model Precipitation (mm) for the Nyundo Sub-basin.

The historical annual precipitation for the basin was 1290 mm. By the end of the century precipitation increases to 1390 mm for RCP 4.5 and 1520 mm for RCP 8.5.

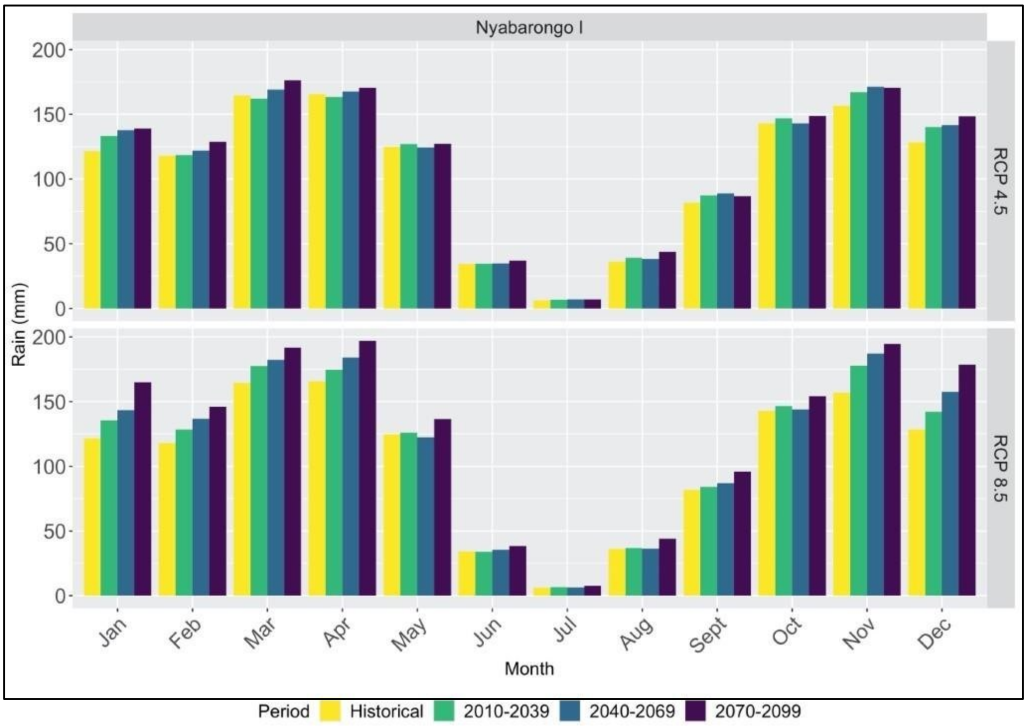


Figure 34: Average Multi-Model Precipitation (mm) for the Nyabarongo I Sub-basin.

The historical annual precipitation for the basin was 1280 mm. By the end of the century precipitation increases to 1380 mm for RCP 4.5 and 1550 mm for RCP 8.5.

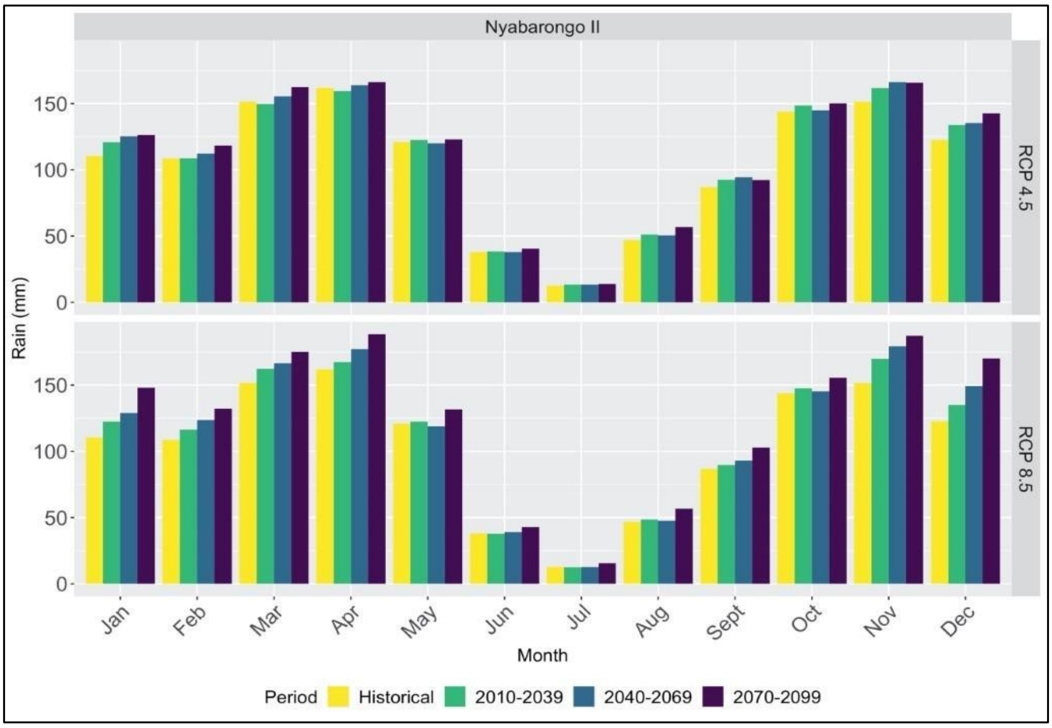


Figure 35: Average Multi-Model Precipitation (mm) for the Nyabarongo II Sub-basin.

The historical annual precipitation for the basin was 1260 mm. By the end of the century precipitation increases to 1360 mm for RCP 4.5 and 1510 mm for RCP 8.5.

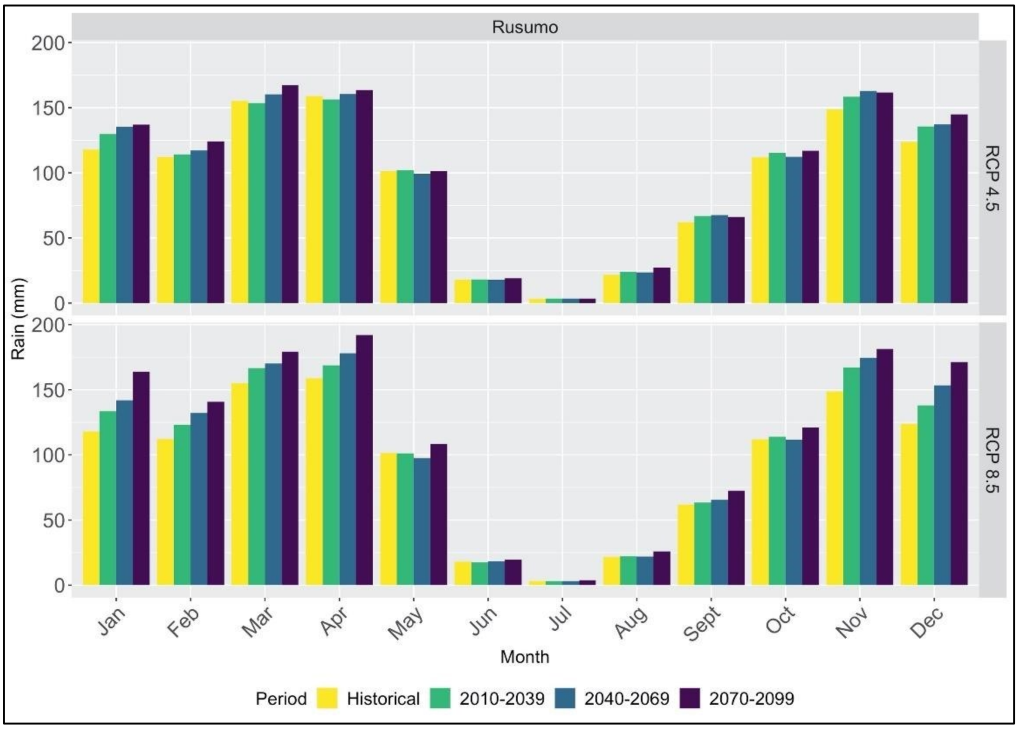


Figure 36: Average Multi-Model Precipitation (mm) for the Rusumo Sub-basin.

The historical annual precipitation for the basin was 1130 mm. By the end of the century precipitation increases to 1230 mm for RCP 4.5 and 1380 mm for RCP 8.5.

Figures 37 - 43 present the changes in minimum and maximum temperature for each sub-basin. Overall temperature increases are observed for all sub-basins, with more noticeable increases under RCP 8.5 than RCP 4.5. The average minimum annual temperature increase by the end of the century is 2.2 °C under RCP 4.5 and 4.2 °C under RCP 8.5. The average maximum annual temperature increase by the end of the century was 2°C under RCP 4.5 and 3.8°C under RCP 8.5.

The power plant in the hottest basin is the Rusumo power plant with an annual minimum historical temperature in the basin around 14.3° C, followed by the Nyabarongo I basin with an annual average minimum temperature historically of 12.5 °C.

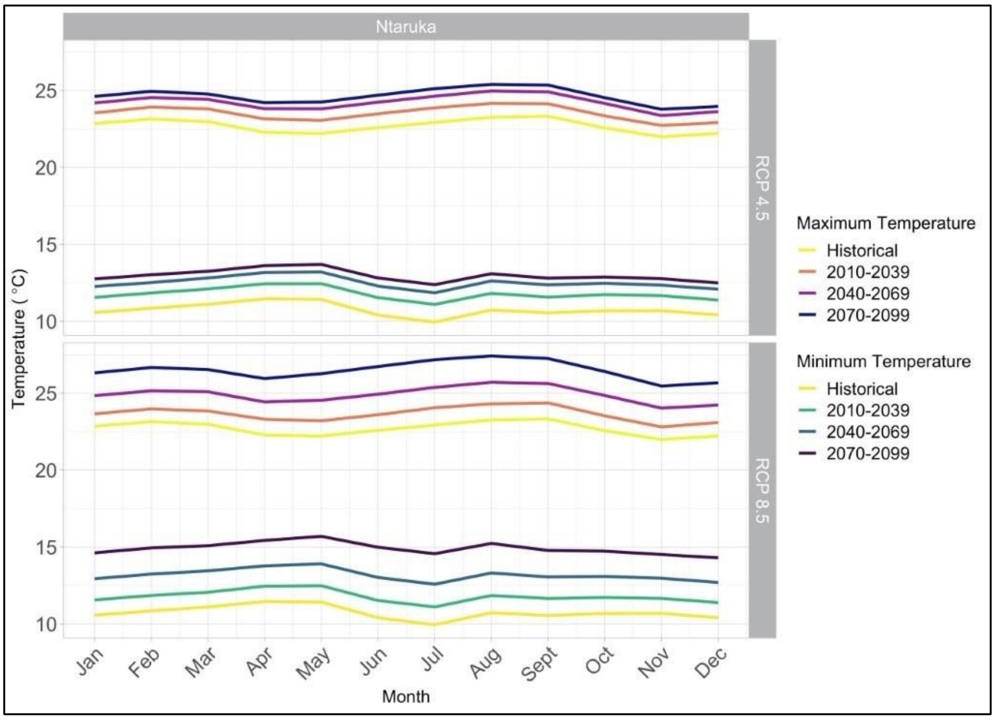


Figure 37: Changes in Minimum and Maximum Temperature (°C) for the Ntaruka Subbasin.

Average minimum temperature increases from 10.7 °C in the historical period to 13 °C under RCP 4.5 and 14.9 °C under RCP 8.5. Average maximum temperature increases from 22.7 °C

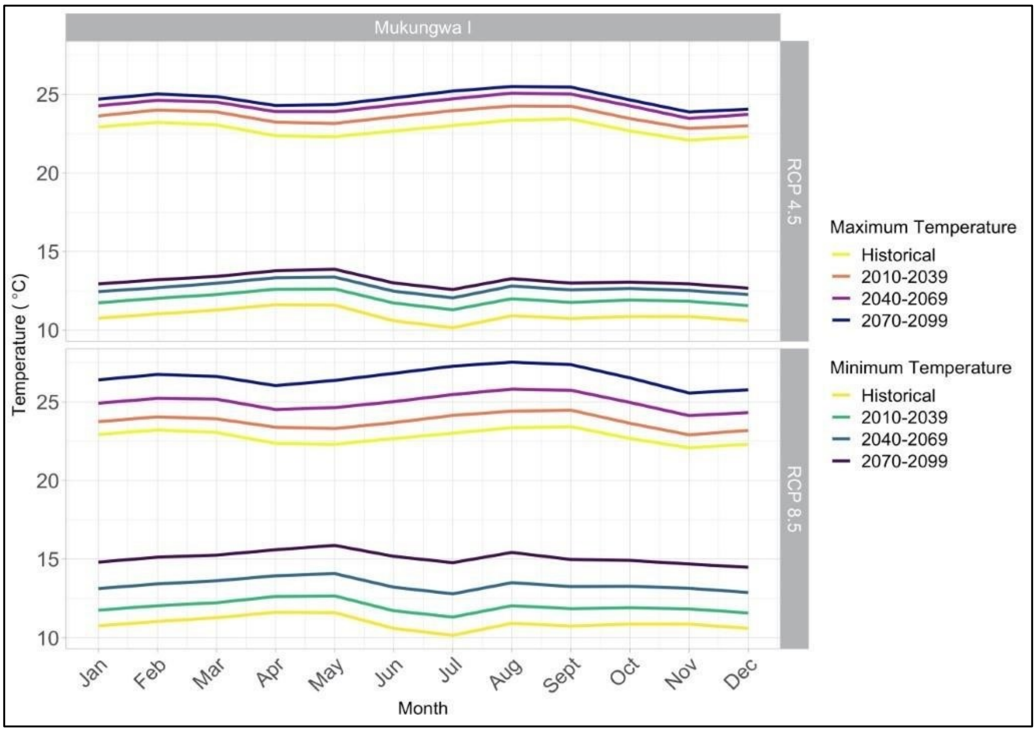


Figure 38: Changes in Minimum and Maximum Temperature (°C) for the Mukungwa I Sub-basin.

Average minimum temperature increases from 10.9 °C in the historical period to 13.1 °C under RCP 4.5 and 15.1 °C under RCP 8.5. Average maximum temperature increases from 22.

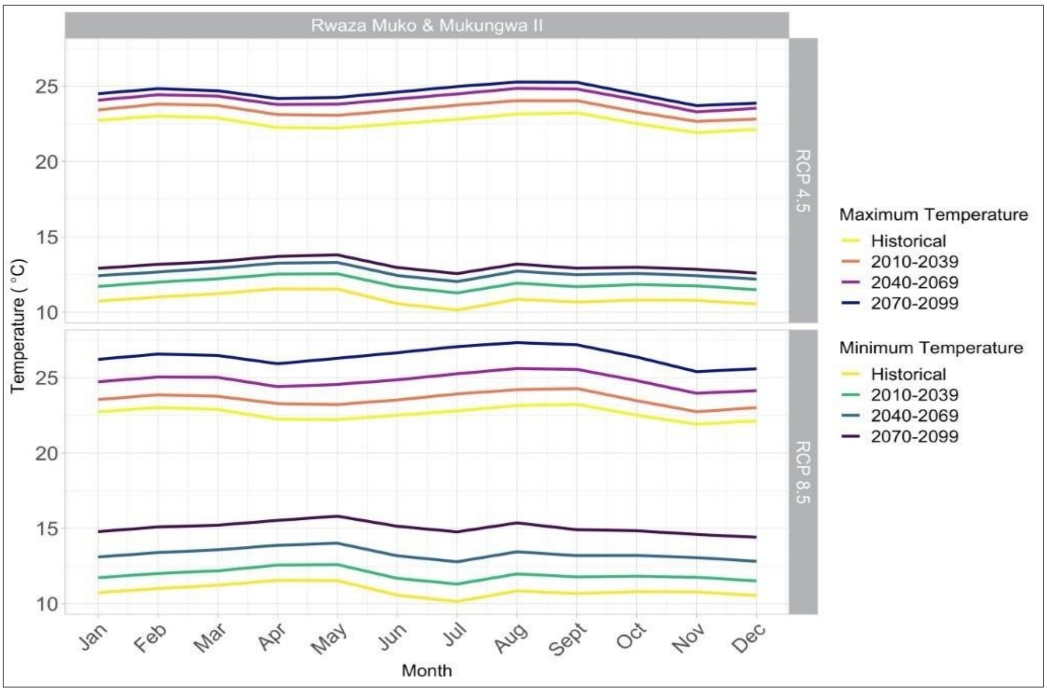


Figure 39: Changes in Minimum and Maximum Temperature (°C) for the Rwaza Muko/Mukungwa II Sub-basin.

Average minimum temperature increases from 10.9 °C in the historical period to 13.1 °C under RCP 4.5 and 15.0 °C under RCP 8.5.

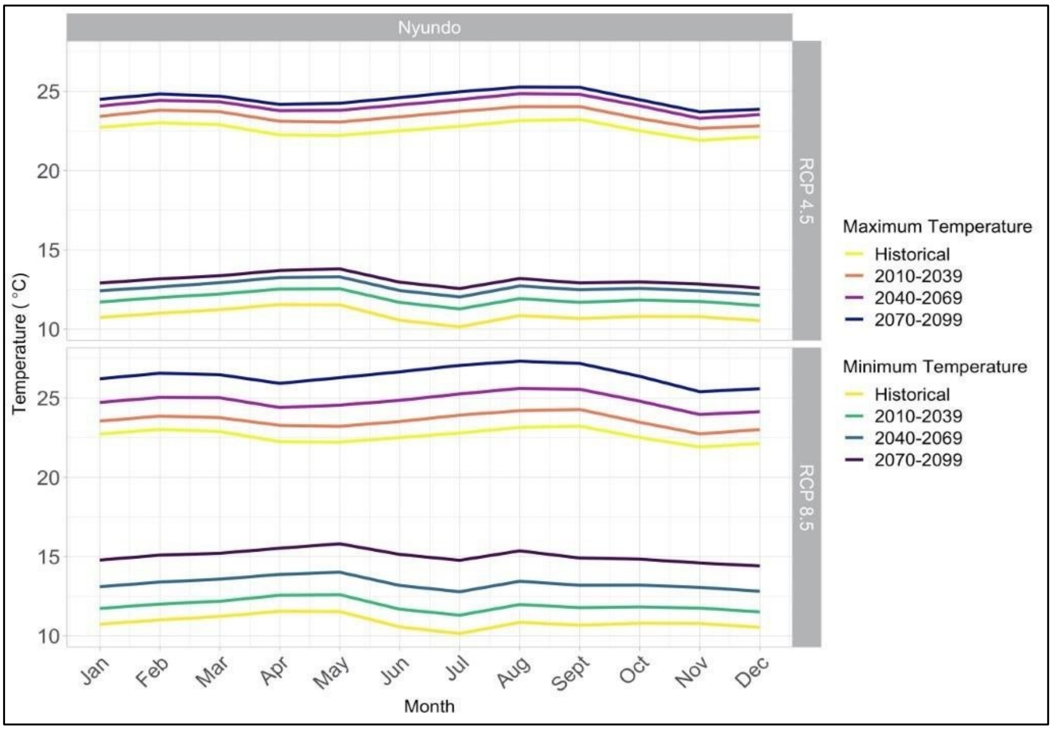


Figure 40: Changes in Minimum and Maximum Temperature (°C) for the Nyundo Subbasin.

Average minimum temperature increases from 10.9 °C in the historical period to 13.1 °C under RCP 4.5 and 15.0 °C under RCP 8.5. Average maximum temperature increases from 22.6 °C

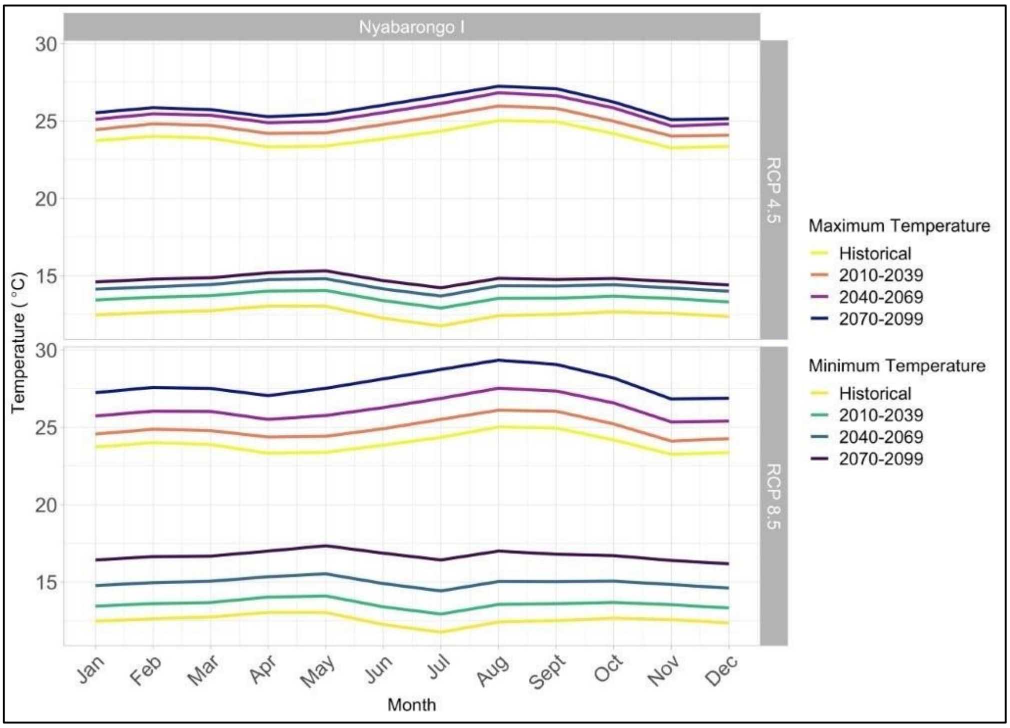


Figure 41: Changes in Minimum and Maximum Temperature (°C) for the Nyabarongo I Sub-basin.

Average minimum temperature increases from 12.5 °C in the historical period to 14.8 °C under RCP 4.5 and 16.7 °C under RCP 8.5.

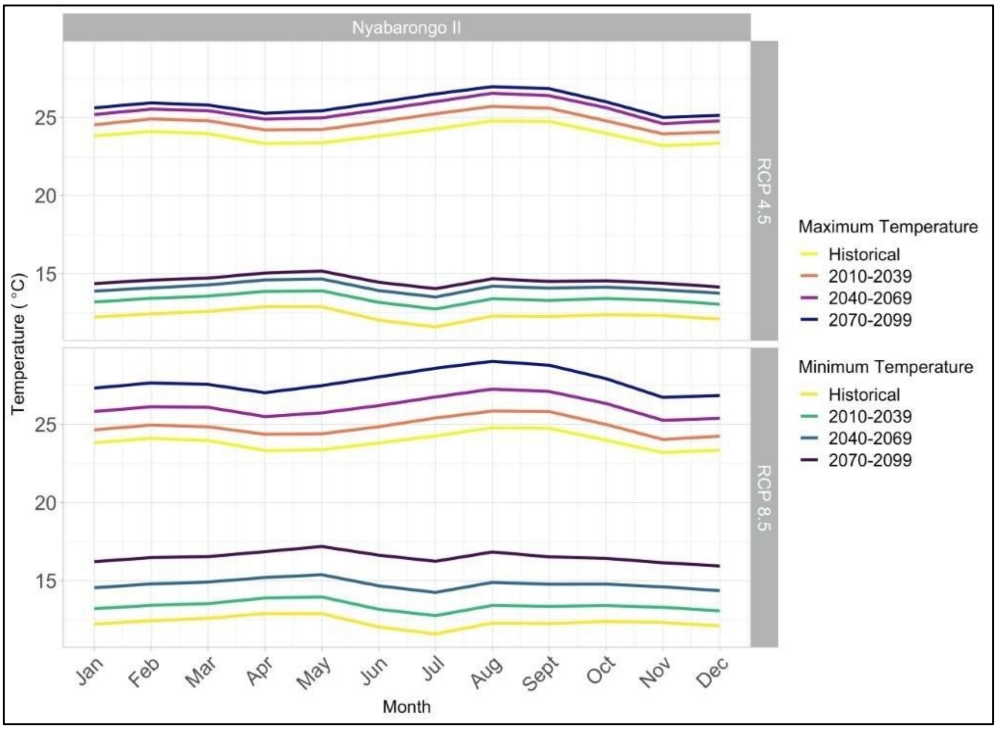


Figure 42: Changes in Minimum and Maximum Temperature (°C) for the Nyabarongo II Sub-basin.

Average minimum temperature increases from 12.3 °C in the historical period to 14.5 °C under RCP 4.5 and 16.5 °C under RCP 8.5.

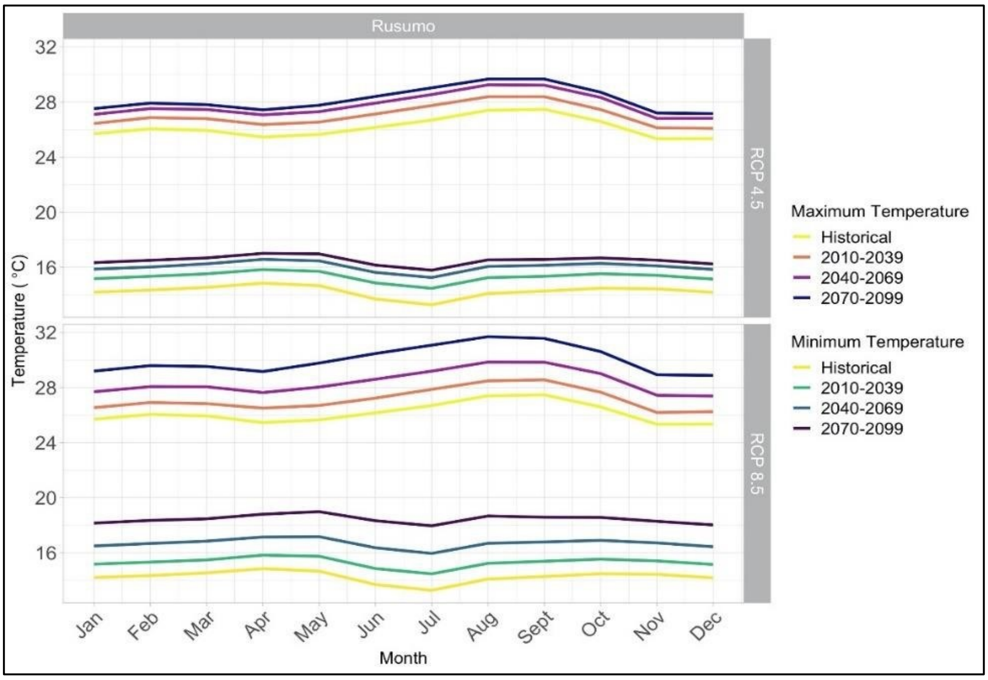


Figure 43: Changes in Minimum and Maximum Temperature (°C) for the Rusumo Subbasin.

Average minimum temperature increases from 14.3 °C in the historical period to 16.5 °C under RCP 4.5 and 18.4 °C under RCP 8.5. Average maximum temperature increases from 26.1 °C

Finally, *Figure 26* presents the changes in Potential Evapotranspiration (PET) for all basins. The values - calculated with the Hargreaves method - increases from 1470 mm annually to 1540 mm by the end of the century under RCP 4.5 and 1620 mm under RCP 8.5.

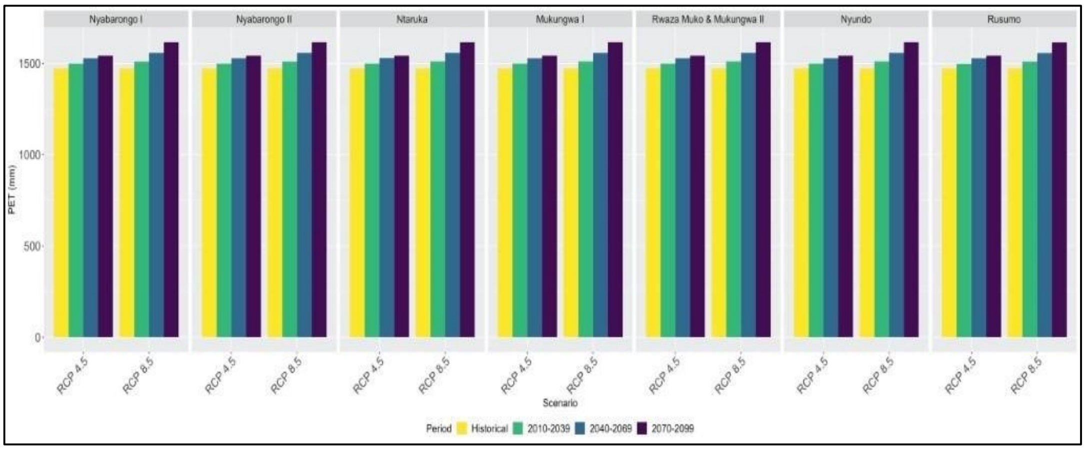


Figure 44: Changes in Potential Evapotranspiration (Hargreaves Method).

Historical PET was on average 1470 mm for all sub-basins and it increases by the end of the century to 1540 mm under RCP 4.5 and 1620 under RCP 8.5.

Overall, all basins are becoming hotter and wetter as the century progresses under both climate scenarios and the multi-model ensemble.

These figures collectively also underscore that climate change can significantly impact hydropower potential through shifts in rainfall patterns, streamflow regimes, and temperature. For Rwanda's Least Cost Power Development Plan, incorporating these climate projections ensures that capacity expansions and technology choices (e.g., adding solar, battery storage, or flexible thermal plants) remain cost-effective and reliable over the long term. By capturing a range of possible futures, the study can propose adaptation strategies that maintain energy security while supporting national goals for sustainable development.

9.3. Streamflow & Available Capacity[29]

Projections for future power plant available capacity (available MW of hydropower considering electricity maximization) were run under the two emission scenarios and the 21 GCMs.

Each future run was divided into 3 time frames for the purpose of the analysis; the near future (2010-2039), the mid-century (2040-2069), and the end of the century (2070-2099).

Even though the end of the century projections might not be as relevant for present-day planning decisions, it is important to include them and to understand the potential shifts in trends. Additionally, infrastructure typically outlasts its planned life and therefore power plants and reservoirs built nowadays might still be operating by the end of the century with the proper retrofits.

To be able to understand the trends under the two different scenarios of climate change, projections are compared to a historical experiment run. The historical experiment (1970-2005) is conducted using the outputs for the retrospective run of the GCMs. This comparison is performed using this historical experiment to keep the biases of the GCMs constant and to be able to understand the trends of climate change into the century.

All sub-basins are compared, even if the power plants have not been constructed yet. The ability to compare changes between what could have been generated in the past and the future allows us to understand the impact of climate change on hydropower in Rwanda.

The results section is divided into **two** parts:

I. A streamflow analysis which includes monthly average naturalized streamflow and an analysis of the 10th percentile (*low flow*), the 50th percentile (*median flow*), and the 90th percentile (*high flow*) streamflow.

II. A second analysis of simulated normalized available capacity considering power plants operate with all available streamflow as run-of-river or reservoir every month of the analysis period. Three seasons were analysed: *Rainy Season 1 (January - May)*, *Dry Season (June - September)*, and *Rainy Season 2 (October - December)*.

9.3.1. Streamflow Analysis

The following section presents the results obtained for streamflow under the two scenarios, and three different time frames: near future (*2010-2039*), mid-future (*2040-2069*) and end-of-century (*2070-2099*). *Figures 45 - 51* present the average monthly results from the multi-model ensemble.

Overall, there are increases in streamflow for all sub-basins which can be seen in greater detail in *Tables 15, 16, and 17.* These tables presents results for the low streamflow (10th

29 Available capacity is defined as the maximum monthly capacity in MW, constrained by the power plant's installed capacity, the simulated streamflow can maintain for a specific time frame

percentile), median streamflow (50th percentile), and high streamflow (90th percentile). The changes in projected flow encompass all the results from the 21 GCMs.

Tables 15, 16, and 17[30] present the results for the three cases respectively: *low flow*, *median flow* and *high flow*.

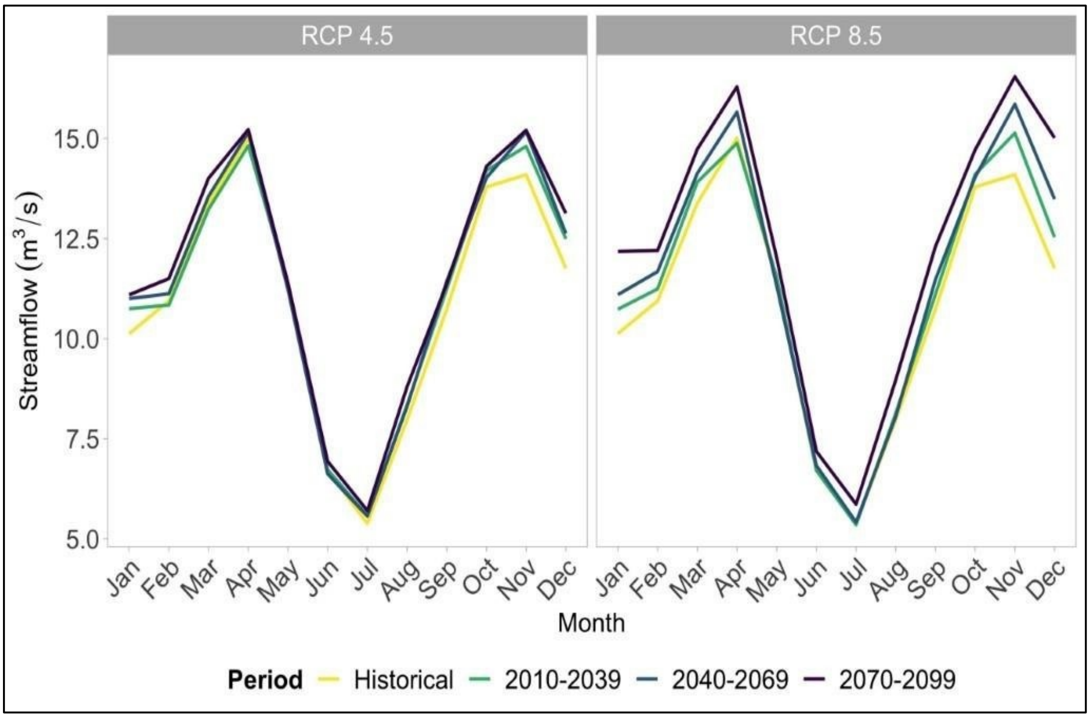


Figure 45: Average monthly streamflow from the multi-model ensemble for the Ntaruka subbasin

30 These results present naturalized streamflow without considering water demand within the basin.

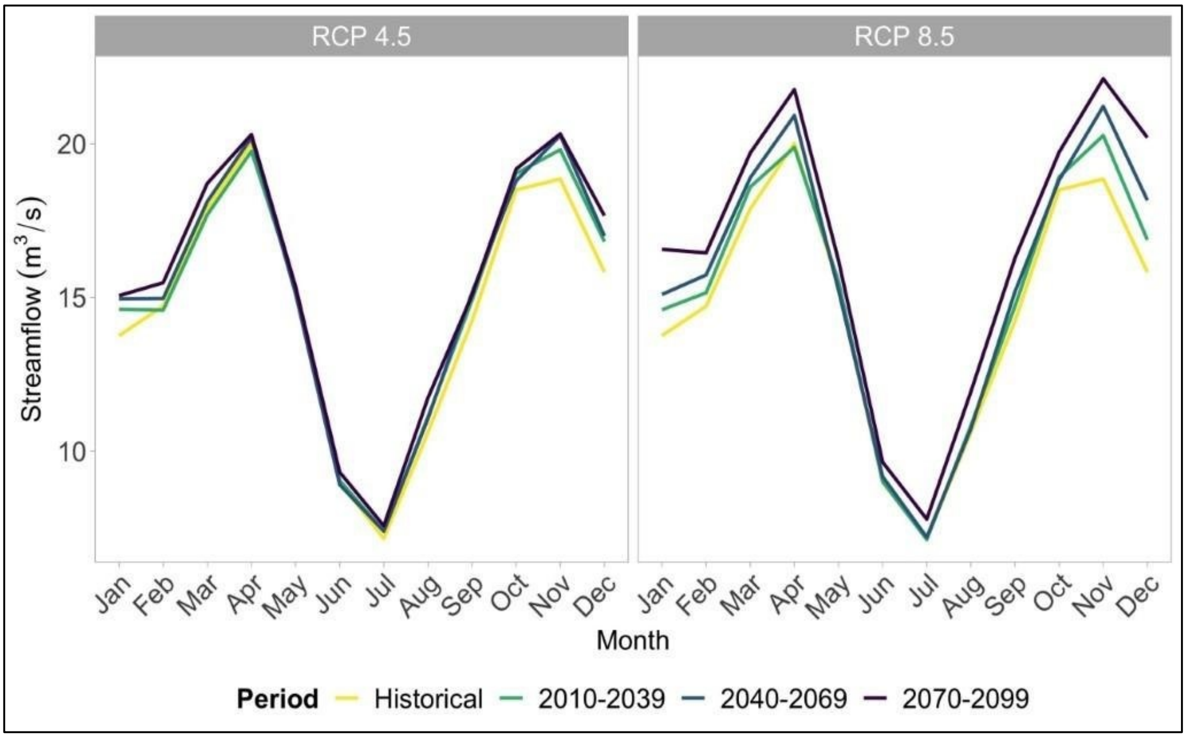


Figure 46: Average monthly streamflow from the multi-model ensemble for the Mukungwa I sub-basin

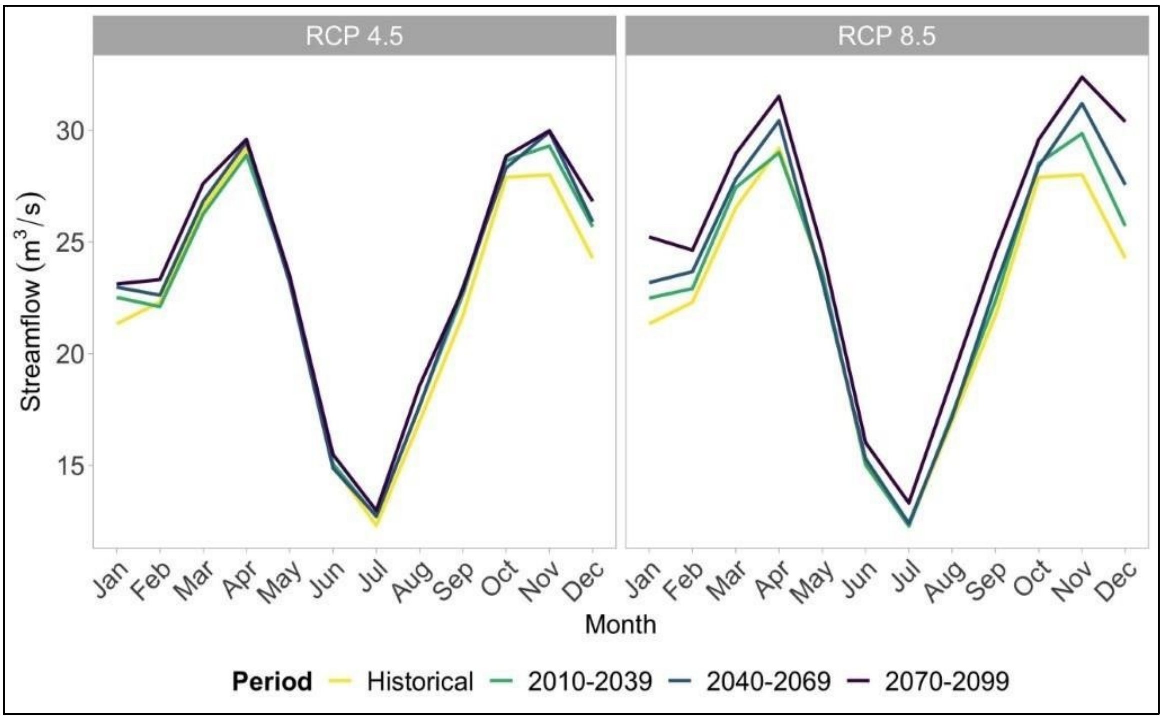


Figure 47: Average monthly streamflow from the multi-model ensemble for the Rwaza-Muko/Mukungwa II sub-basin

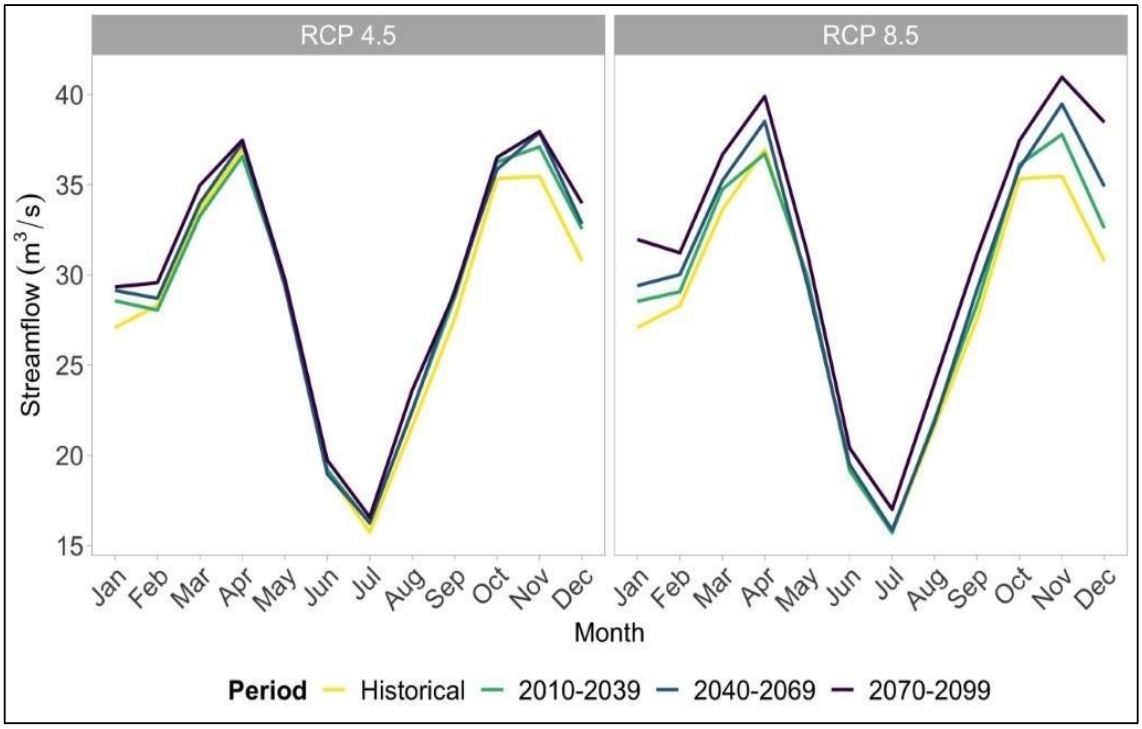


Figure 48: Average monthly streamflow from the multi-model ensemble for the Nyundo sub-basin.

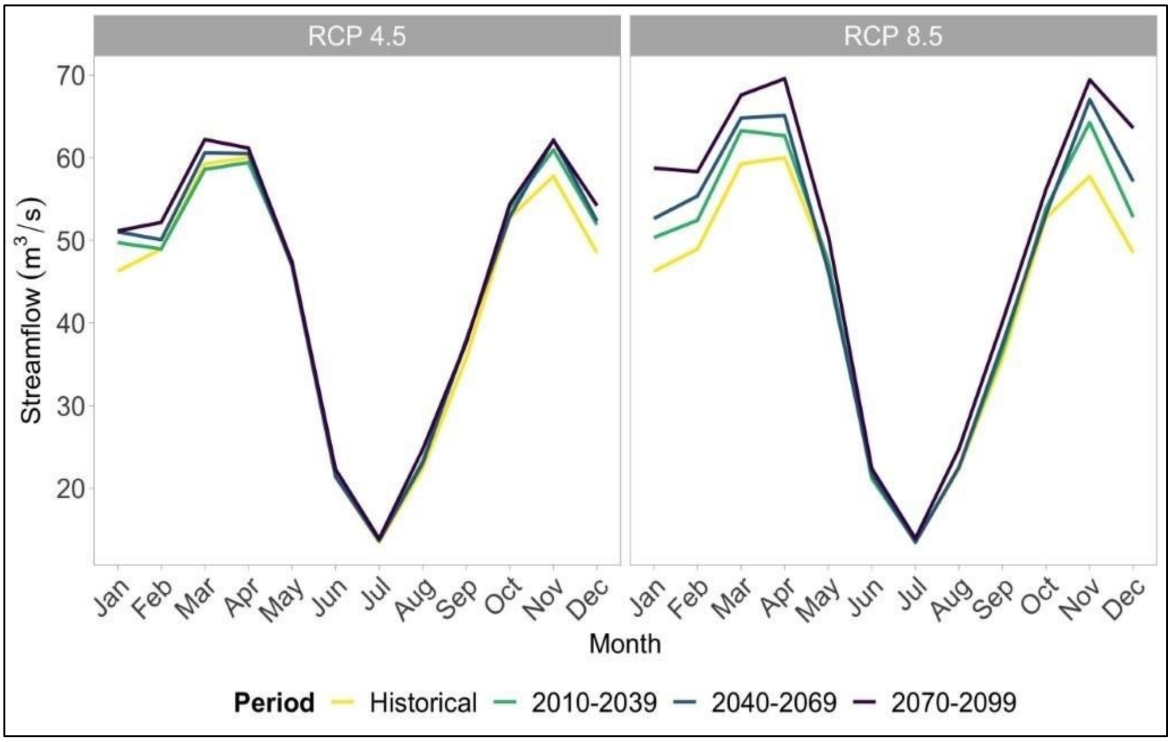


Figure 49: Average monthly streamflow from the multi-model ensemble for the Nyabarongo I sub-basin.

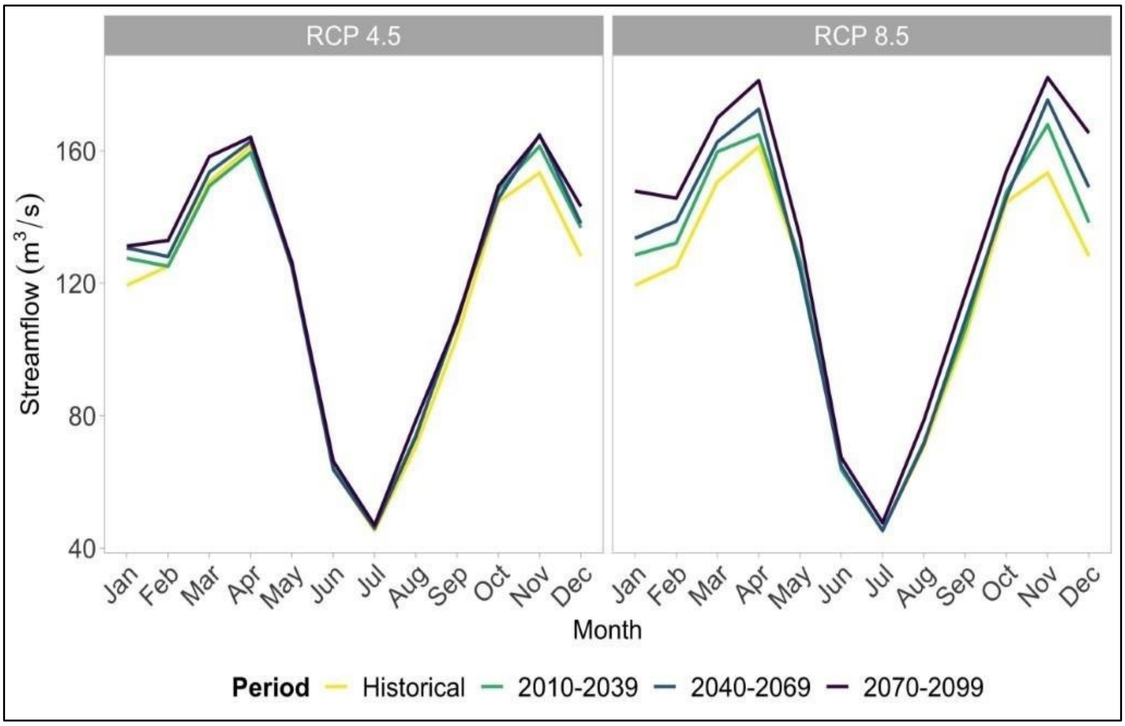


Figure 50: Average monthly streamflow from the multi-model ensemble for the Nyabarongo II sub-basin.

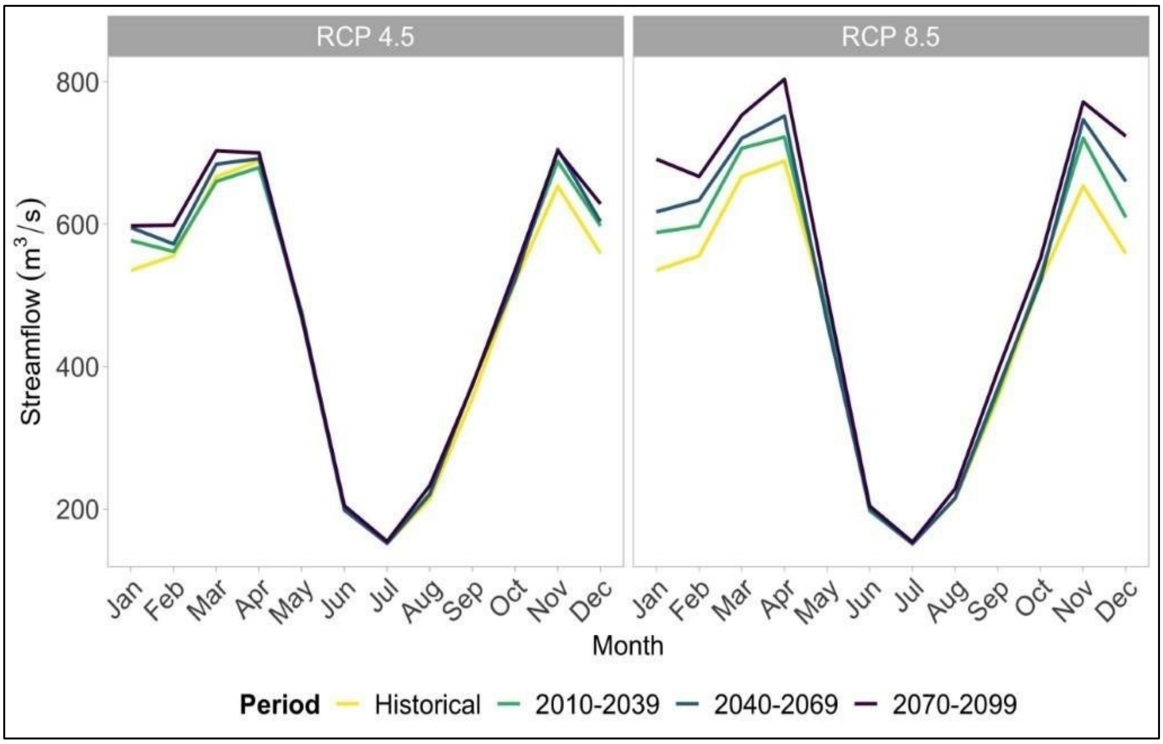


Figure 51: Average monthly streamflow from the multi-model ensemble for the Rusumo sub-basin

Table 15: Projected Changes in 10th Percentile Naturalized Streamflow

Sub-basin	***Change in Projected 10th Percentile Flows***

	RCP 4.5			RCP 8.5		
	2010-2039	2040-2069	2070-2099	2010-2039	2040-2069	2070-2099
Nyabarongo I	1.5%	-7.1%	-1.4%	-4.3%	-8.1%	1.9%
Ntaruka	0.3%	-4.0%	-0.8%	-7.4%	-7.5%	7.4%
Mukungwa I	-1.2%	-5.0%	-1.5%	-8.8%	-8.6%	7.0%
Rwaza & Mukungwa II	-0.8%	-5.5%	-1.3%	-8.9%	-8.9%	5.3%
Nyundo	-0.7%	-5.3%	-1.2%	-8.8%	-8.8%	5.4%
Nyabarongo II	2.7%	-3.1%	1.6%	-4.2%	-6.5%	8.2%
Rusumo Regional HPP	2.4%	-4.2%	-0.4%	-2.6%	-7.0%	2.7%

Table 16: Projected Changes in Median (50th Percentile) Naturalized Streamflow

Sub-basin	***Change in Projected 50th Percentile Flows***					
	RCP 4.5			RCP 8.5		
	2010-2039	2040-2069	2070-2099	2010-2039	2040-2069	2070-2099
Nyabarongo I	3.8%	3.9%	6.2%	4.4%	6.7%	14.8%
Ntaruka	3.1%	5.1%	7.1%	3.4%	7.1%	15.7%
Mukungwa I	3.1%	5.1%	7.0%	3.9%	6.9%	14.9%
Rwaza & Mukungwa II	3.3%	4.9%	7.0%	3.8%	7.1%	15.6%
Nyundo	3.3%	4.8%	7.1%	3.8%	7.1%	15.5%
Nyabarongo II	4.3%	5.2%	6.8%	4.3%	8.1%	15.2%
Rusumo Regional HPP	3.5%	4.6%	6.3%	4.5%	6.5%	14.5%

Table 17: Projected Changes in 90th Percentile t Streamflow

Sub-basin	***Change in Projected 90th Percentile Flows***					
	RCP 4.5			RCP 8.5		
	2010-2039	2040-2069	2070-2099	2010-2039	2040-2069	2070-2099
Nyabarongo I	4.7%	8.6%	12.0%	12.3%	20.9%	31.0%
Ntaruka	5.2%	8.3%	10.8%	7.4%	13.9%	24.8%
Mukungwa I	5.1%	8.5%	11.1%	7.5%	14.6%	24.8%

Sub-basin	Change in Projected 90th Percentile Flows					
	RCP 4.5			RCP 8.5		
	2010-2039	2040-2069	2070-2099	2010-2039	2040-2069	2070-2099
Rwaza & Mukungwa II	5.1%	8.5%	11.5%	7.2%	13.6%	24.2%
Nyundo	5.1%	8.5%	11.5%	7.2%	13.6%	24.2%
Nyabarongo II	4.5%	7.4%	10.7%	7.0%	13.6%	24.9%
Rusumo Regional HPP	4.6%	7.5%	11.5%	9.1%	15.7%	27.4%

The results show a trend of increasing streamflow for the median and the high flow. The increases vary depending on the period analysed but consistently progressing as the horizon is extended further into the century.

The highest increases are projected for the high flows under RCP 8.5 (24.2%-31.0%). These increases will potentially translate to increased generation, only constrained by the power plant design characteristics.

On the other hand, the 10th percentile flows show a mix of both decreases and increases. Decreases are mostly projected for the near-future and the mid-century. These decreases are larger under RCP 8.5.

The effect of these decreases in available capacity will be discussed in the following sections. It might not necessarily affect generation overall. Additionally, adjacent reservoirs might help buffer some of the effects of decreased streamflow.

9.3.2. Normalized Available Capacity

Figures 52 and 53 show the projected changes in normalized available capacity. Additionally, *changes in available capacity (MW) are analysed for each month of the system considered between the projection runs and the control run*.

Three different seasons are portrayed: *rainy season 1*, *dry season*, and *rainy season 2*.

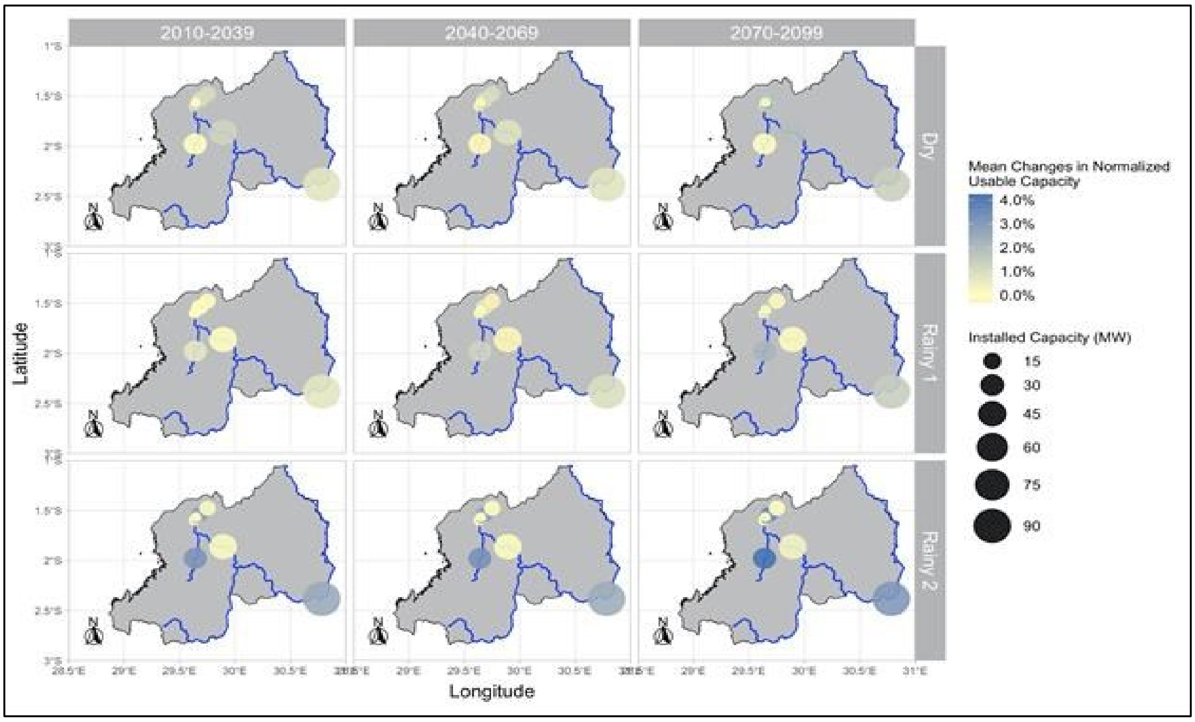


Figure 52: Rwanda's mean relative changes in normalized available capacity for RCP 4.5.

The analysis spans between the historical reference (1970-2005), the near future (2010-2039), the mid-century (2040-2069), and the end-of-the-century (2070-2099).

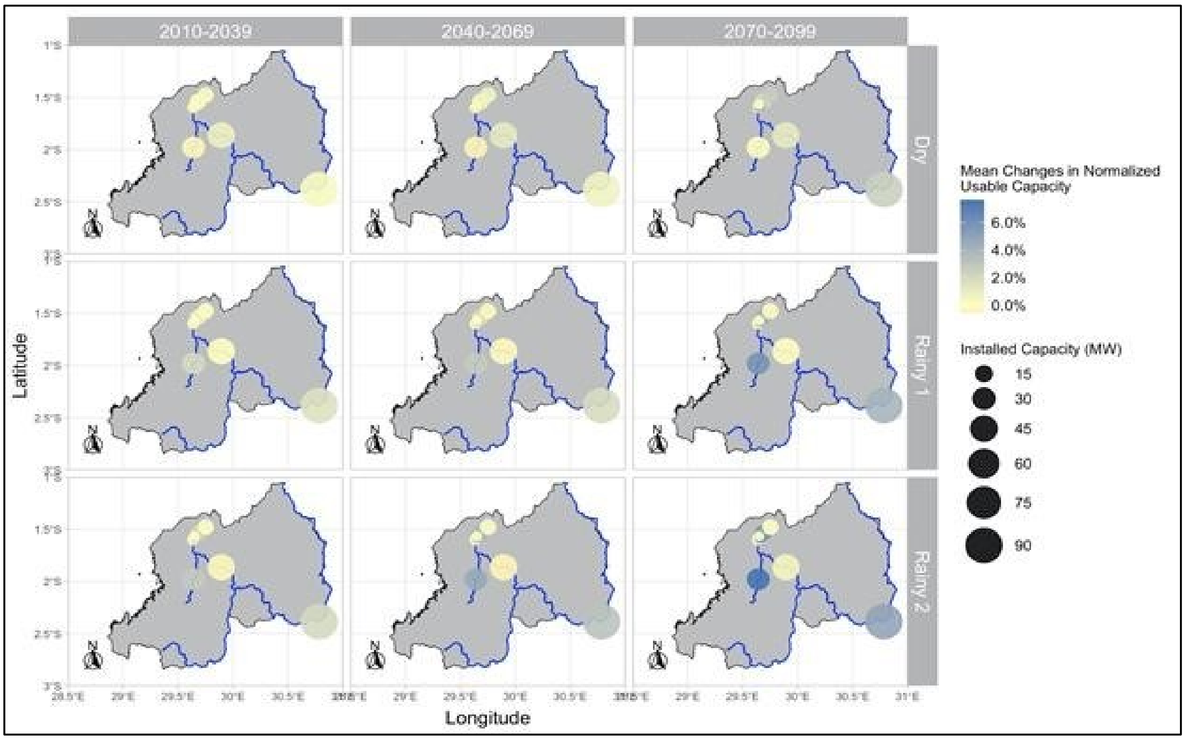


Figure 53: Rwanda's mean relative changes in normalized available capacity for RCP 8.5.

The analysis spans between the historical reference (1970-2005), the near future (2010-2039), the mid-century (2040-2069), and the end-of-the-century (2070-2099).

Rusumo Hydropower Project, which is currently under construction, would seem to experience increases in capacity factor throughout the century under all scenarios, especially during the rainy seasons (both) and the end of the century.

Smaller power plants like the Nyundo (4.5 MW) and Rwaza (2.6 MW) have less variability during the year of available capacity. These power plants should be able to operate at full capacity during the rainy seasons, given their lower design flow. During the drier months both power plants experience increased variability. Given the size of the power plants however, this should not be problematic for the operations of the system.

Other power plants exhibit increased monthly available capacities. This would be beneficial, given that all increases in streamflow can be utilized for power output and do not seem to pose any danger to their structures.

An increase in streamflow, and consequently available capacity is projected for the seven Rwandan hydropower plants analysed through the 21st century. These changes vary in magnitude depending on the power plant.

10. Conclusion & Proposed actions

10.1. Conclusions

i. Generation resources continue to be dominated by Hydro power in the near term, with the penetration of methane, and peat. In the longer planning horizon, the emergence of new technologies is found to be of value in most scenarios (natural gas, solar, hydro pumped storage, waste).

ii. The registered demand growth over the past 5 years fell short relative to the initial expansion scenarios, this is in part due to the Covid-19 effect that saw 2% growth in the year 2020, but prospects of recovery are already in sight with 12.5% growth realised and sustained since 2021, and a forecast growth of 15% in 2025[31]. Demand growth in the years ahead is also contingent to the timely materialization of key projects of Vision 2050 as captured in the demand forecasts.

iii. The resource assessment analysis has improved the perspective on generation resources; this will continue to be included in subsequent LCPDP updates for broader expansion paths.

iv. From the climate change impact study on hydropower availability, an increase in streamflow - and consequently available capacity is projected for the seven Rwandan hydropower plants analysed through the 21st century. These changes vary in magnitude, depending on power plant design characteristics.

10.2. Proposed Actions

i. Analysis of potential for power trade: imports and export contracts (2-*10 years or longer*) to neighbouring countries to leverage the potential in having completed interconnections and the countries location and membership to both the CAPP & EAPP.

ii. Due to their technical operational considerations and high-level development aspirations, the expansion of VRE should ensure that all Solar technologies in the future should not be signed PPAs unless they embed storage. It is recommended to consider energy storage systems (reservoirs, pumped storage, batteries and others) as strategic resources as part of adaptation measures for grid stability and for climate change.

iii. As the grid expands, the Government of Rwanda should consider investments in generation expansion, especially for non-market services such as: frequency and voltage control; black start; grid congestion relief; transmission & distribution deferral; transmission forecasting error correction. These services would require be highly priced if outsourced from private developers.

iv. There is also an emergent need to upgrade the grid code to align with necessary ancillary services required to continuously provide reliable electricity.

v. To consolidate efforts towards realization of cleaner and greener electricity generation building on the foundation laid down from the Rwanda Electricity Generation Resource Assessment Study towards meeting various national

31 The optimism of demand growth is raised in December 2023 update.

decarbonisation agenda (NDCs, Rwanda SE4All Action Agenda, COP Presidential pledges, etc..), feasibility studies are proposed to be undertaken for generic projects that can serve as peaking power plants and help in functions/ancillary services. These include, in order of priority the following studies:

a. Feasibility study for a solar park with BESS (180 MW).
b. Feasibility study for Utility-scale Battery Energy Storage Systems (30 MW).
c. Feasibility study for Conversion of thermal PPs to gas-fired plant (natural gas pipeline).
d. Updating of studies for Nyabarongo-2 downstream pumped storage.

This would enable to increase the share of Government-owned PPs, not to mention proposed action (iii) above.

vi. In addition, to further diversify power generation sources towards renewable energy, there is a need to:

a. Carry out exploratory studies for further methane-fired power generation potential
b. Revive explorations in Geothermal resource potential.
c. Conduct a baseline study for Green Hydrogen.
d. Initiate feasibility study exploring the potential for natural gas pipeline to harness regional south-south cooperation.

vii. Furthermore, to meet energy requirements to meet national development aspirations of the Rwanda Vision 2050 (mid-term 2035-target-objectives), it is imperative to fast-track studies and preliminaries for nuclear power generation & the corresponding enabling power trade.

viii. Accelerate further demand growth inducing policies to continue electricity demand stimulation in line with development aspirations as set forth in the NST2, and Rwanda Vision 2050.

ix. In line with upcoming generation, emerging trends in energy intensities such as in electric mobility, the potential embedded generation, and as part of the loss reduction efforts, it is important to plan different tariff regimes that are business boosting, while optimizing system peak and off-peak demand.

x. To renegotiate PPAs of projects not yet started for an optimal integration schedule depending on demand evolution.

10.3. Way forward

	CHALLENGE	RECOMMENDATION(S)
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) • Demand forecasting to be updated regularly based on more realistic plans and assumptions aligned to the future planning cycle.
2.	Ascertaining the exact amount of lake methane that can be	• An updated and comprehensive resource study has been conducted to ascertain the existing resources in Rwanda. These resources include solar, hydro (including

	CHALLENGE	RECOMMENDATION(S)
	exploited for electricity production in an economical and sustainable way.	pumped storage), wind, geothermal, waste to power, peat and lake Kivu methane. There is need to conduct feasibility studies in identified resource locations to ascertain the exact amounts of reserves.
3.	Demand Growth Inducing policies to be expanded	• GOR policy decision to be taken to stimulate demand growth of over 10%. Especially to catch up form unrealized growth in the previous years • Required infrastructure for industrial parks to be in place and the need to accelerate implementation of flagship Vision 2050 • Introduce more commercial and industrial demand and provide incentives for consumption during system off-peak. • (Introduction of reduced tariffs for consumers during off-peak periods to promote load shifting).
4.	System Stability	• Installed capacity of new power plants should not exceed a multiple of 15% of Rwanda grid capacity (peak demand) at the time of CoD. This is to avoid high spinning reserves, grid instability and resulting high costs involved in case of disturbances caused by the new plant.
5.	Grid modernization	• Need to direct more investments to non-market services (Voltage Control; Black Start; Grid Congestion Relief; T&D Deferral; etc…) that are important to maintaining reliable electric system. • There is also a need to develop peaking power plants and/or battery storage systems to absorb excess off-peak capacity and load shedding.
6.	Climate change	• Consider energy storage (reservoirs, pumped storage, batteries storage systems, electrolysers, and others) as peaking generation resources as part of adaptation measures to meet climate change goals (decarbonization).
7.	Emissions factors and compatibility with Rwanda's NDC	• More emission scenario analysis is planned to be included in future updates for mitigation and adaptation purposes, on the adverse impacts of climate change in the electricity sector

References

1. African Union Development Agency (AUDA-NEPAD), Modelling Continental Masterplan (2nd Phase): Integrated Continental Demand Forecasts-Scenario Analysis. June 2022.
2. African Union Development Agency (AUDA-NEPAD), Modelling Continental Masterplan (2nd Phase): Resource Assessment and Techno-economic Data and Assumptions Report. June 2022.
3. East Africa Energy Program (EAEP), Rwanda Resource Study for Electricity Generation Sources. May 2022. Kigali, Rwanda.
4. East African Power Pool (EAPP), East African Power Pool Power Balance Statement 2021 Edition. March 2023. Addis Ababa, Ethiopia.
5. Ministry of Finance and Economic Planning (MINECOFIN), Economic Development and Poverty Reduction Strategy II 2013-2018. Republic of Rwanda, 2013. Kigali, Rwanda.
6. Ministry of Finance and Economic Planning (MINECOFIN), National Strategy for Transformation (NST1) 2017–2024. Republic of Rwanda. 2018 Kigali, Rwanda.
7. Integrated Planning Review. Main Report.
8. Energy Investment Forum, Methane, Peat and Waste-to-Power Projects in Rwanda: Opportunities for Investment in Rwanda. February 29, 2012. Kigali, Rwanda.
9. Ministry of Infrastructure (MININFRA), Rwanda Energy Policy. March 2015. Republic of Rwanda. Kigali, Rwanda.
10. Ministry of Infrastructure (MININFRA), Energy Sector Strategic Plan. 2013/14-2017/18. Republic of Rwanda. March 2015. Kigali, Rwanda.
11. Ministry of Infrastructure (MININFRA), Energy Sector Forward Looking JSR for FY 2015/16 Report,. Republic of Rwanda. June 2015. Kigali, Rwanda.
12. Ministry of Infrastructure (MININFRA), Energy Sector Performance Report/Backward Looking JSR for FY 2014/15, November 2015. Republic of Rwanda. Kigali, Rwanda.
13. Ministry of Infrastructure (MININFRA), Rural Electrification Strategy. Republic of Rwanda. June 2016. Kigali, Rwanda.
14. Ministry of Infrastructure (MININFRA), Energy Sector Strategic Plan, 2018/19 - 2023/24. Republic of Rwanda, September 2018. Kigali, Rwanda.
15. National Institute of Statistics of Rwanda (NISR), The Third Integrated Household Living Conditions Survey (EICV3). Main Indicators Report.
16. National Institute of Statistics of Rwanda (NISR), Ministry of Finance and Economic Planning (MINECOFIN) [Rwanda], 2012. Fourth Rwanda Population and Housing Census. Thematic Report: Population Projections
17. National Institute of Statistics of Rwanda (NISR), Integrated Household Living Conditions Survey (EICV), Economic Activity Thematic Report. March 2016.
18. National Institute of Statistics of Rwanda (NISR), Fifth Rwanda Population and Housing Census. Thematic Report: Population Projections, July 2023.
19. National Institute of Statistics of Rwanda (NISR); Fifth Rwanda Population and Housing Census, Main Indicators Report, February 2023.

20. National Institute of Statistics of Rwanda (NISR), Fifth Rwanda Population and Housing Census, Thematic Report: Population size, structure, and spatial distribution, July 2023.
21. National Institute of Statistics of Rwanda (NISR), Fifth Rwanda Population and Housing Census, Thematic Report: Housing & Household Characteristics, July 2023.
22. National Institute of Statistics of Rwanda (NISR), Gross Domestic Product and its Structure 2023, March 2024.
23. NELSAP - Consultancy Services for Power Network Analysis of the Interconnection of Electric Grids of NEL countries.
24. Rwanda Utility Regulatory Agency (RURA), Strategic Plan 2013-2018. June 2013. Kigali, Rwanda.
25. The project preparation of electricity development plan for sustainable geothermal energy development in Rwanda. (Book 1 of 4). Summary & Introduction. Final report. March 2015. Republic of Rwanda. Ministry of Infrastructure. Rwanda Energy Group. Japan International Cooperation Agency (JICA)
26. The International Renewable Energy Agency (IRENA) and Lawrence Berkeley National Laboratory, Renewable Energy Zones for the Africa Clean Energy Corridor: Multi-criteria Analysis for Planning Renewable Energy. October 2015.
27. Climate Change & Hydropower Generation in Rwanda: Assessment of Current & Future Power Plants (Ph.D. Candidate, Department of Engineering and Public Policy Department of Civil and Environmental Engineering, Carnegie Mellon University).

Abbreviations & Acronyms

BAS : Business as Usual

CAPEX: Capital Expenditure

CF : Capacity Factor

CIF : Cost, Insurance & Freight

CNSE : Cost of Non-Served Energy

CoD : Commercial Operation Date

EDCL : Energy Development Corporation Limited

EDPRS: Economic Development & Poverty Reduction Strategy

EICV : Integrated Household Living Conditions Survey (Enquête Intégrale sur les Conditions de Vie des Ménages)

EPD : Energy Private Developers

ESSP : Energy Sector Strategic Plan

EUCL : Energy Utility Corporation Limited

GCM : General Circulation Models

GDP : Gross Domestic Product

GHG : Green House Gas

HPP : Hydro Power Plant

IAEA : International Atomic Energy Agency

IPP : Independent Power Producer

IRENA: International Renewable Energy Agency

ITCZ : Inter-Tropical Convergence Zone

km : Kilometre

KW : Kilowatt

kWh : Kilowatt hour

LCPDP: Least Cost Power Development Plan

MESSAGE: Model for Energy System Supply Alternatives & their Environmental Impact

MINECOFIN: Ministry of Finance and Economic Planning

MININFRA: Ministry of Infrastructure

MoE : Ministry of Environment

MW : Megawatt

MWh : Megawatt Hours

NASA : National Aeronautics and Space Administration Agency

NEL : Nile Equatorial Lakes

NELSAP: Nile Equatorial Lakes Subsidiary Action Programme

NEX-GDDP: NASA Earth Exchange Global Daily Downscaled Projections

NISR : National Institute of Statistics of Rwanda

NOx : Nitrogen Oxides

NST : National Strategy for Transformation (with its various iterations NST-1, NST-2)

OPEX : Operational Expenses

PET : Potential Evapotranspiration

PP : Power Plant

PPA : Power Purchase Agreement

RAEB : Rwanda Atomic Energy Board

RCP : Representative Concentration Pathways

RDB : Rwanda Development Board

REG : Rwanda Energy Group

RES : Rwanda Energy System

RES : Renewable Energy Share

RURA : Rwanda Utility Regulatory Authority

SCE : Shuffled Complex Evolution algorithm

SOx : Sulphur Oxides

SSA : Sub-Saharan Africa

T&D : Transmission & Distribution

TBD : To Be Determined

tCO2 eq: Tonnes of carbon dioxide equivalent

TWh : Terawatts hour

USD : US Dollar