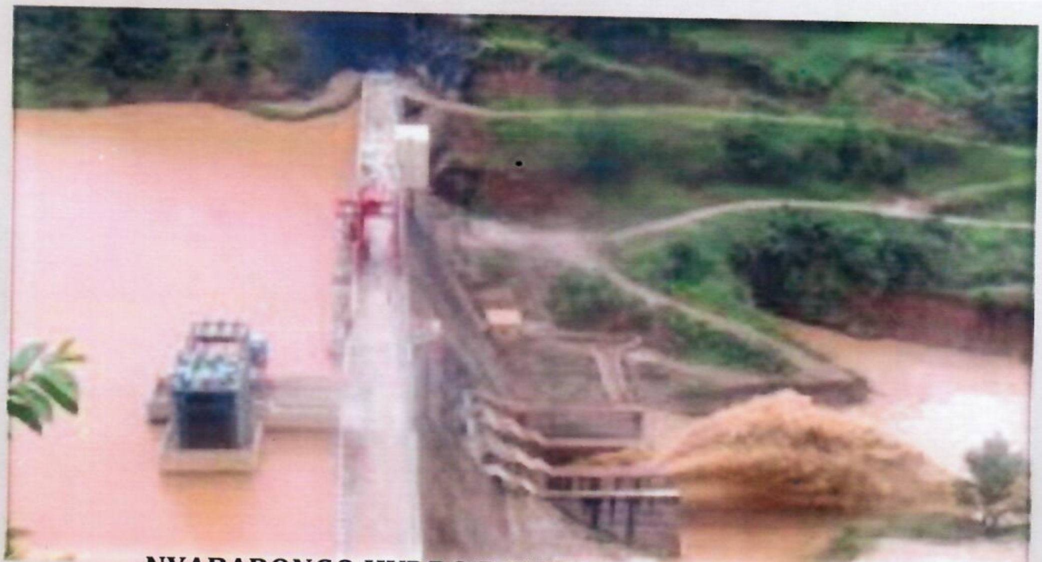
RWANDA: LEAST COST POWER DEVELOPMENT PLAN (LCPDP) 2023 – 2050

June 2023



NYABARONGO HYDRO POWER PLANT, RWANDA

KIVUWATT METHANE GAS POWER PLANT, RWANDA

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 so as to ensure that the tariff affordability objectives are being optimized.

The least cost study is segmented into two phases: _entry of committed projects_ (**2023 – 2028**) and _the long-term_ (**2028 - 2050**).

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

Rwanda at this time has limited generation resources especially during the dry season when many hydro power plants face water shortage problems. During this period, rental diesel generation is used to supply the peak demand, and this generation comes at a high cost. Efforts are underway however to ascertain the true quantity of existing resources within the country for electricity generation. 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 increases the possibility of increased electricity tariffs and consequent losses incurred by the national power utility, especially if the terms of the power purchase agreements (PPA's) do not match the interests of both parties. REG and the Government should therefore use as the least-cost entry dates, technologies and capacities of committed (signed PPA's) generation plants.

The Least-cost generation expansion results show the emergence of new technologies onto the grid under different development scenarios. These include utility scale solar PV with storage, consumer-sized battery storage services, and hydro pumped storage for higher forecasted domestic and export demand in the longer term. Further research into these new technologies should be carried out, as well as more information comes up, concerning an accurate bottom-up demand forecast and the amount of natural gas to be imported from the planned Tanzania-Rwanda pipeline connection.

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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)

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

MININFRA: Ministry of Infrastructure

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

NST1 : National Strategy for Transformation

OPEX : Operational Expenses

PET : Potential Evapotranspiration

PP : Power Plant

PPA : Power Purchase Agreement

RCP : Representative Concentration Pathways

REG : Rwanda Energy Group

RES : Rwanda Energy System

RES : Renewable Energy Share

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

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 satisfy the forecasted growing demand for electricity within the country while maintaining an acceptable 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.

Other objectives of the plan include:

i. Maximisation of the use of renewable energy within the country's energy mix.
ii. Optimisation of the availability of electricity supply to meet peak demand and avoid the possibility of generating excess capacity.
iii. Adherence to the Rwandan energy policy[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 following section (2) provides a brief overview of Rwanda's energy sector. Section 3 discusses the demand forecast, while sections 4 and 5 cover the existing and planned generation plants within Rwanda. Section 6 provides the least cost planning methodology, generation expansion scenarios and presents the software that was used, while section 7 shows the June 2023 updates. Section 8 outlines and provides a discussion of the least cost results obtained from the least cost modelling. Section 9 covers the recently concluded study on the impact of climate change on hydropower production of the main hydro power plants in the country. Conclusions, proposed actions and way forward are outlined in section 10.

2. Rwanda Energy Sector Overview

Rwanda is a land-locked country with a surface area of 26,338 km^2 and a growing population of 12.7 million[4]. It is densely populated with a 2020 GDP at 816 (current) USD/capita[5]. 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 NST1 period (2017-2024). Ensuring 100% access to affordable and modern sources of energy is essential to achieve this target.

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

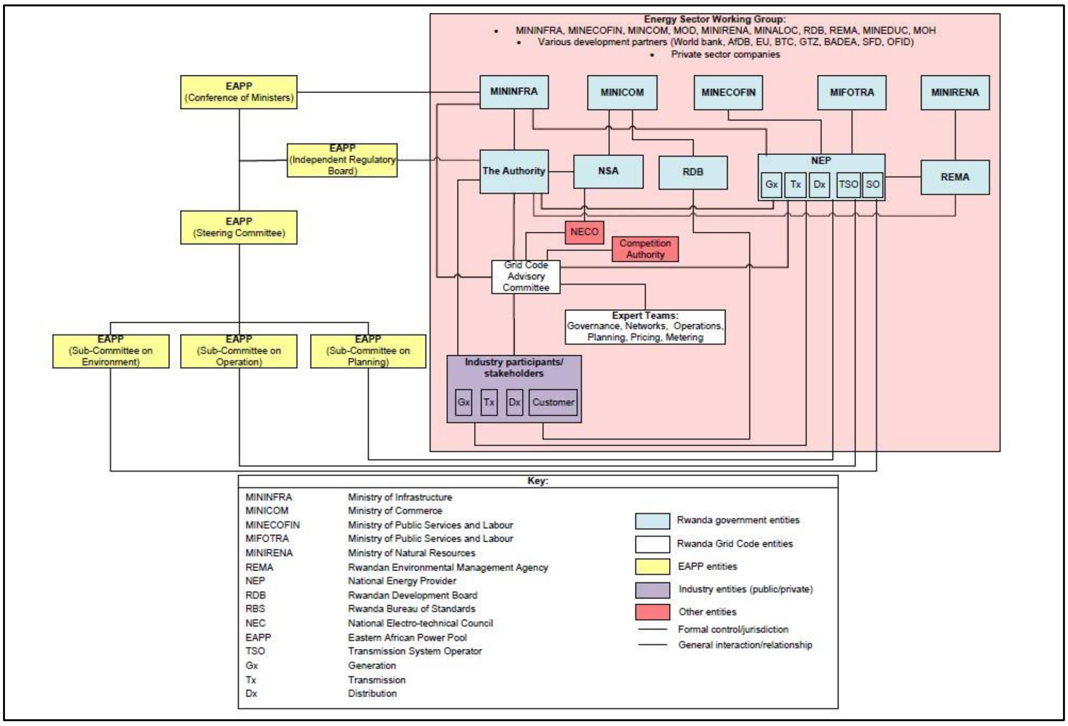

Figure 1: Rwanda's Current Energy Sector Structure

[4] NISR 2021 Statistical Yearbook. [5] NISR 2021 Statistical Yearbook.

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

3. Demand Forecast

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

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

i. Historical records of electricity sales by consumer category and geographical area.
ii. Chronological demand records over days, weeks, months and years are required to determine the relationship between electricity sales and the amount of generation capacity required. The load profile is used to determine what types of generating capacity are needed.
iii. Economic and demographic historical data on economic performance and population.
iv. Economic and demographic projections of either the power utility, an economic planning ministry or from some other governmental entity.
v. Energy end-use data, e.g. percentage of different consumer categories that use specific electric appliances and the amount of electricity used per customer per end use.

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

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

Econometric forecasting investigates statistically significant historical relationships between economic variables and electricity sales or peak demand. Variables used to develop econometric relationships may include household income, electricity prices (by consumer group), prices for other household necessities, employment rates (by sector and sub-sector), labor 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[5], which are widely available.

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

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

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

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

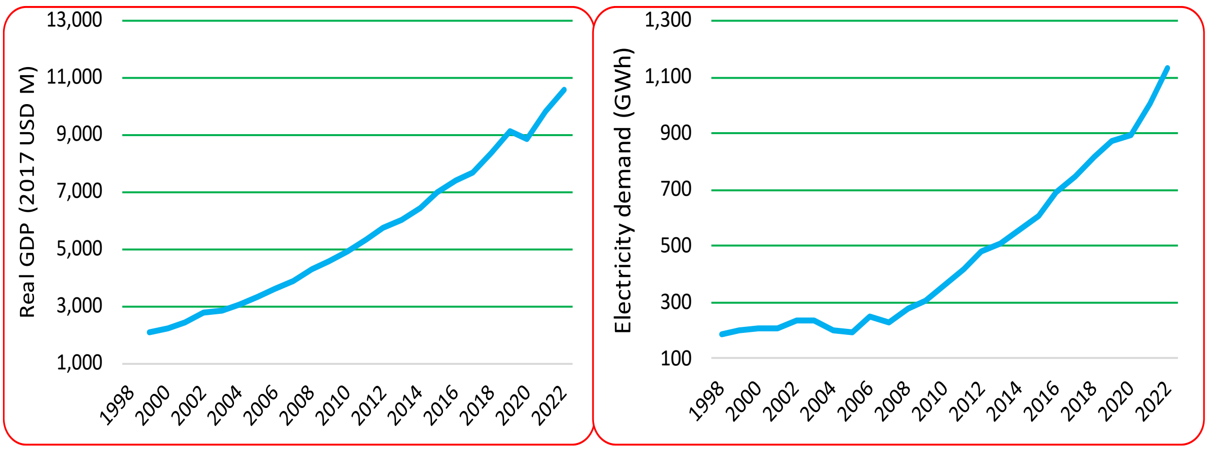

Figure 2: Rwanda Historical GDP and Electricity Consumption Data.

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. Electricity demand forecasts were then calculated in line with recent historical trends, using existing hourly load curves for the years 2017-2022. Peak and energy demand forecasts over the next 18 years were calculated as shown in *Table 1* below.

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

Year	Scenario: 8% growth		Scenario: 10% growth		Scenario: 12% growth		Scenario: 10%, 5% growth		Scenario: 8.6% till 2035, 5% after 2035	
	Peak demand (MW) (8% growth)	Total Electricity Demand (GWh) (8% growth)	Peak demand (MW) (10% growth)	Total Electricity Demand (GWh) (10% growth)	Peak demand (MW) (12% growth)	Total Electricity Demand (GWh) (12% growth)	Peak demand (MW) (5% after 2030)	Total Electricity Demand (GWh)* (5% after 2030)	Peak demand (MW) (5% after 2035)	Total Electricity Demand (GWh)* (5% after 2035)
2016	119	690.0	119	690.0	119	690.0	119	690.0	119	690.0
2017	134	750.0	134	750.0	134	750.0	134	750.0	134	750.0
2018	139	821.0	139	821.0	139	821.0	139	821.0	139	821.0
2019	147	876.0	147	876.0	147	876.0	147	876.0	147	876.0
2020	155	895.0	155	895.0	155	895.0	155	895.0	155	895.0
2021	171	1005.0	171	1005.0	171	1005.0	171	1005.0	171	1005.0
2022	185	1131	185	1131.0	185	1131.0	185	1131.0	185	1131.0
2023	200	1221	204	1244	207	1267	204	1244	201	1228
2024	216	1319	224	1368	232	1419	224	1368	218	1334
2025	233	1425	246	1505	260	1589	246	1505	237	1449
2026	252	1539	271	1656	291	1780	271	1656	257	1574
2027	272	1662	298	1822	326	1994	298	1822	279	1709
2028	294	1795	328	2004	365	2233	328	2004	303	1856
2029	318	1939	361	2204	409	2501	361	2204	329	2016
2030	343	2094	397	2424	458	2801	397	2424	357	2189
2031	370	2262	437	2666	513	3137	417	2545	388	2377
2032	400	2443	481	2933	575	3513	438	2672	421	2581
2033	432	2638	529	3226	644	3935	460	2806	457	2803
2034	467	2849	582	3549	721	4407	483	2946	496	3044
2035	504	3077	640	3904	808	4936	507	3093	539	3306
2036	544	3323	704	4294	905	5528	532	3248	566	3471
2037	588	3589	774	4723	1014	6191	559	3410	594	3645
2038	635	3876	851	5195	1136	6934	587	3581	624	3827
2039	686	4186	936	5715	1272	7766	616	3760	655	4018
2040	741	4521	1030	6287	1425	8698	647	3948	688	4219
2041	800	4883	1133	6916	1596	9742	679	4145	722	4430
2042	864	5274	1246	7608	1788	10911	713	4352	758	4652
2043	933	5696	1371	8369	2003	12220	749	4570	796	4885
2044	1008	6152	1508	9206	2243	13686	786	4799	836	5129
2045	1089	6644	1659	10127	2512	15328	825	5039	878	5385
2046	1176	7176	1825	11140	2813	17167	866	5291	922	5654
2047	1270	7750	2008	12254	3151	19227	909	5556	968	5937
2048	1372	8370	2209	13479	3529	21534	954	5834	1016	6234
2049	1482	9040	2430	14827	3952	24118	1002	6126	1067	6546
2050	1601	9763	2673	16310	4426	27012	1052	6432	1120	6873

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, 8.65% demand growth during 2017-2022, an 10% annual electricity demand growth rate is used for Rwanda's generation expansion scenario development and expansion planning with sensitivity analyses conducted on a bound between 5% and 10% annual demand growth since 2030 onwards as presented in section .

Figure 3 below illustrates the forecasted energy and peak demand growth.

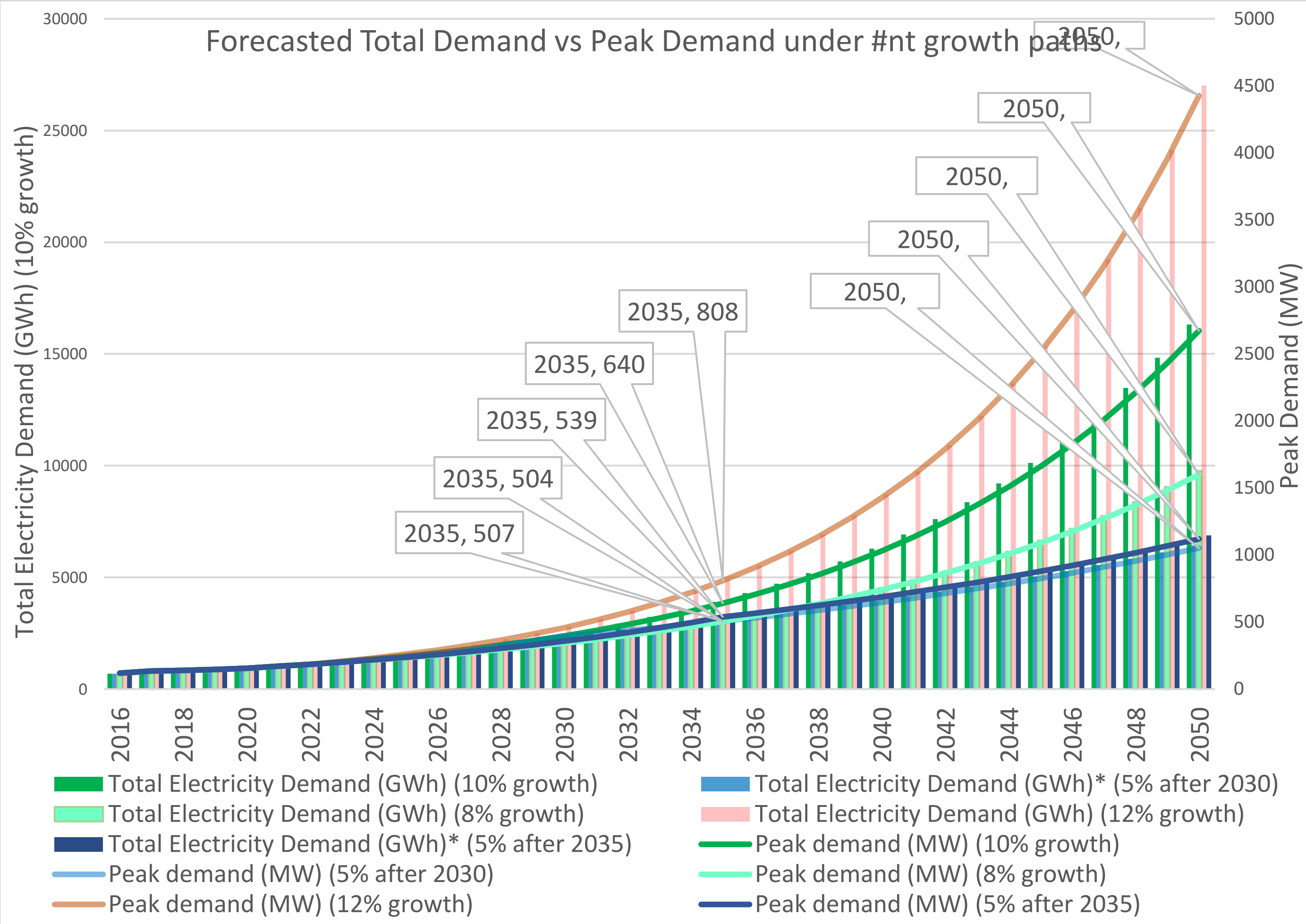

Figure 3: Forecasted Total Demand and Peak Demand

4. Existing Generation Plants

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

Table 2: Existing generation plants

No	Plant Name	Installed Capacity (MW)	Capacity Factor (%)	Available Capacity (MW)	Owner	COD	Type of Technology
1	Ntaruka	11.25	33.61	3.8	GoR	1959	Hydro
2	Mukungwa I	12	61.56	7.4	GoR	1982	Hydro
3	Nyabarongo I	28	68.54	19.2	GoR	2014	Hydro

No	Plant Name	Installed Capacity (MW)	Capacity Factor (%)	Available Capacity (MW)	Owner	COD	Type of Technology
4	Gisenyi	1.7	65	1.1	Prime Energy	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	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	2013	Hydro
25	Rukarara II	2.2	52.5	1.2	Prime Energy	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	Prime Energy 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
	S-total	**107.3**		**58.0**			
35	Jabana 1	7.8	95	7.4	GoR	2004	Diesel

No	Plant Name	Installed Capacity (MW)	Capacity Factor (%)	Available Capacity (MW)	Owner	COD	Type of Technology
36	Jabana 2	21	95	20.0	GoR	2009	HFO-Diesel
37	SO Energy	30	95	28.5	So Energy&SP	2017	Diesel
	S-total	**58.8**		**55.9**			
38	Gishoma	15	85	12.8	Gasmeth Energy Ltd	2016	Peat
39	Hakan	70	61.2	42.8	Hakan	2021	Peat
	S-total	**85**		**55.6**			
40	Kivuwatt Phase I	26.19	91.03	23.8	Contour Global	2016	Methane
41	KP1	3.6	0	0.0	GoR	2009	Methane
	S-total	**29.8**		**23.8**			
42	Jali	0.25	14.00	0.0	Mainz Stadwerke/Local Agency	2007	Solar
43	GigaWatt	8.5	17.08	1.5	Gigawatt Global	2013	Solar
44	Nasho Solar	3.3	16.08	0.5	GoR	2017	Solar
	S-total	**12.05**		**2.0**			
45	Mururu 1	4.1	100	4.1	SNEL Sarl	1957	Imports
46	Mururu II	12	100	12.0	SNEL Sarl	1957	Imports
47	Gatuna	2	100	2.0	UETCL	2016	Imports
	S-total	**18.1**		**18.1**			
	Grand Total	**311.1**		**213.4**			

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

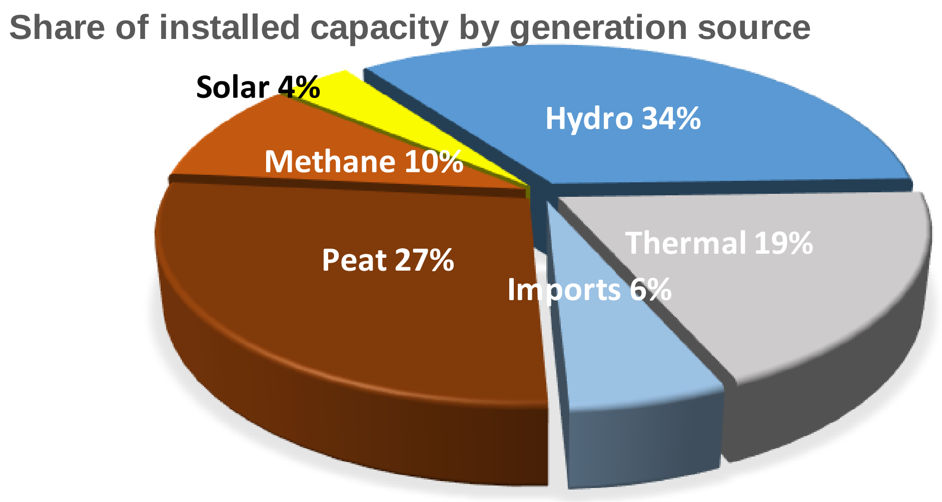

Figure 4: Current Energy Mix

5. Planned Generation Projects

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

Table 3: Planned Generation Projects (Committed)[6]

#	Power Station	Nominal Capacity (MW)	Planned COD
	Non-renewable power plants		
1	SPLK (_1)	28	2023
2	SPLK (_2)	28	2024
	Hydro Stations<=5MW		
3	Ntaruka A	2.1	2023
4	Kavumu MHPP	0.38	2023
5	Nyirahindwe 1	0.909	2024
6	Nyirahindwe 2	0.359	2024
7	Ngororero	2.7	2026
8	Nyundo	4.5	2027/8
9	Rwondo	2.3	2026
10	Base 1	2.9	2025
11	Base 2	2.9	2026
12	Kore	1.3	2024
13	Rucanzogera	1.9	TBD
14	Rukore	2	2023
15	Bihongore	4.22	TBD
	Hydro Stations>5MW		
16	Rukarara VI	9.76	2026
17	Nyabarongo II	43.5	2027
	Regional Projects (hydro)		
16	Rusumo	26.7	2023
17	Rusizi III	68	2029
18	Rusizi IV	95.9	TBD

Other committed & generic generation additions that are scenario-specific are presented in Table 6, section 8.1 of Installed Capacity and Peak Demand under the reference scenario.

In addition, the following installed capacity have recently been added to the grid.

#	Power Plant	Installed Capacity (MW)	Technology Type
1	Hakan Peat-to-Power (IPP)	35	Peat
2	Ntaruka A	2	Hydro
3	Kavumu-Mwange	0.33	Hydro

[6] TBD : To Be Determined.

#	Power Plant	Installed Capacity (MW)	Technology Type
4	Import (Mirama-Shango	40	Import
	TOTAL	**77.33**	

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 (Jabana II, Jabana I and 30 MW of SO Energy), as well as seasonal inputs from the big hydro storage power plants on the system. The use of diesel during these hours hikes up the generation cost, and consequently the electricity tariff.
- A power network analysis [7] 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 [8] was set to ensure alignment with global trends towards decarbonization of the energy sector. This was therefore an important factor

[7] 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.
[8] Energy Sector Strategic Plan (ESSP)

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 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:

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 the optimization of an objective function (in our case least-cost expansion: the discounted cost of energy supply from various sources) under defined constraints.

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

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

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

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.

$$\sum \text{Production} - \sum \text{Consumption} \geq 0 \text{ at all levels of energy supply in the network and must meet demand at all moments in time based on available supply (variable or otherwise) and demand.}$$

Equation 4: Balance Equation

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

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

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

MESSAGE has the unique ability of modelling seasonal (renewable) supply alternatives through the use of seasonal supply divisions[9], which suits the hydro dominant supply existing within Rwanda[10], as shown in *Figure 5*.

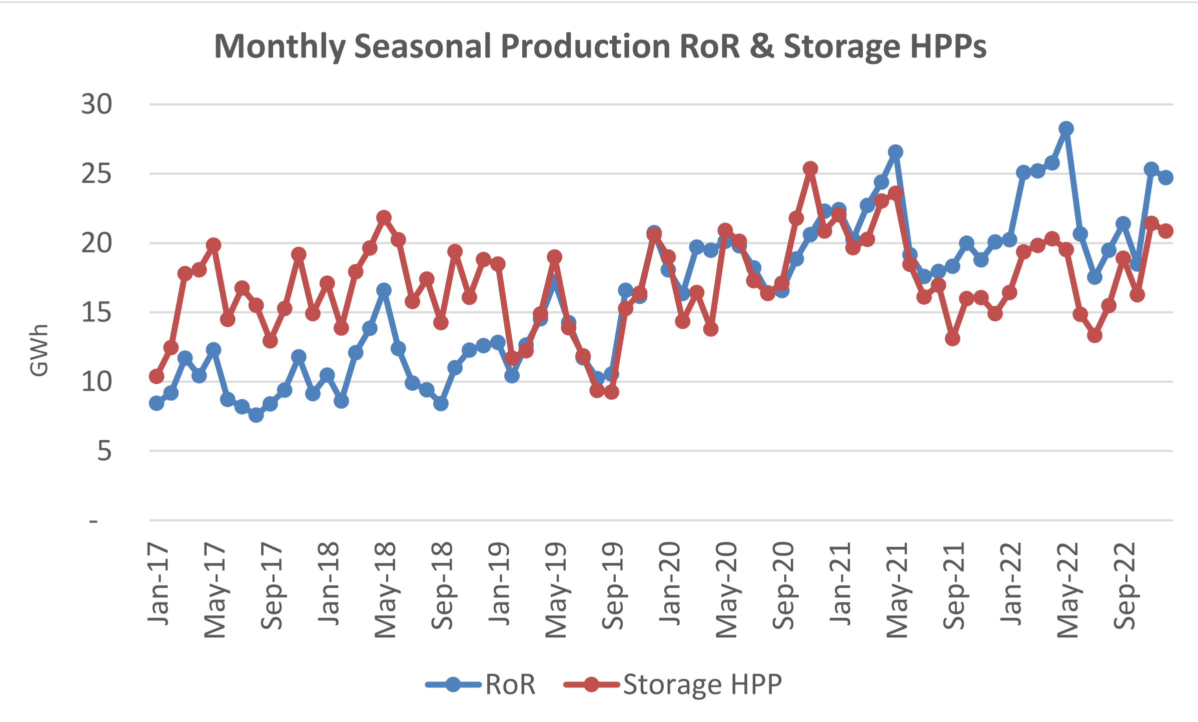

Figure 5: Hydro Power Plant Seasonal Variation

Hourly availability and production profiles of hydro and solar power plants were obtained, consolidated and the resulting operation regimes were fed into individual power plants such that their seasonal variation was captured in the most accurate way possible. The results were therefore not only based on plant design

[9] 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.
[10] See total installed capacity vs firm capacity difference in *Table 2*

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 50 MW. Upon completion, Hakan will be 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[11].

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

[11] Rwanda ESSP 2018.

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 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.

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.

Import/Export options: these are considered as alternative to supply peak demand which is usually supplied mostly by diesel-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 this resource at a relatively cheap cost for several purposes.

- **Sources of Energy**

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

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

Technical characteristics include:

i. **Inputs** (e.g., natural gas, nuclear fuel, electricity).

ii. **Outputs** (e.g., electricity, heat, etc.)

iii. **Conversion efficiency characteristics** (e.g., heat rate, efficiency, losses, etc.)

iv. **Conversion capacity parameters** (i.e., installed capacity).

v. **Any other technical aspects** and/or assumptions as deemed relevant by the modeller.[12]

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[13]** – 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.

[12] e.g. forced outage rates, load curves for seasonal output, maintenance periods, refueling periods, lifetime, degradation of technical characteristics during lifetime, rehabilitation plans, plant factor, operation time and lifetime.
[13] This was used to model the take-or-pay contracts PPA structure that exists within the Rwandan context.

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

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

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

i. Solar PV (grid-connected utility-storage[14], rooftop PV systems).
ii. Conventional Hydro
iii. Hydro Pumped Storage.
iv. Waste/Biomass Generation.
v. Battery Storage Systems.
v. Natural Gas Fired PPs[15].
vi. Methane Power Plants Capacity Addition[16].
vii. Peat Power Plant Capacity Addition[17].
viii. Nuclear Power Plant (especially in high demand growth scenarios).
ix. Green hydrogen.
x. Distributed wind generation.

6.1.3. Other user-specified data

Anything that is relevant to the objective of the supply alternative study. For the Rwandan context, these include additional equations such as import/export, policy targets for renewable energy penetration into the supply mix, base year, planning horizon, time resolution (e.g., annual analysis, five-year steps), currency, discount rate, reference year for costs, and other data (e.g., energy supply/take-or-pay contracts, etc.)

6.2. Options for data presentation in MESSAGE:

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

1. **Constant ©:** a constant value that is assumed to remain constant throughout the planning horizon.

[14] Use of identified high-yield solar zones in Rwanda from the International Renewable Energy Agency (IRENA). Highyield solar zones were best determined considering several factors, e.g. distance to transmission line/substations/load centres/roads, solar irradiation, population destiny, etc.
[15] 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.
[16] Exploitation of existing methane reserves in the country.
[17] Exploitation of existing peat within the country.

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.

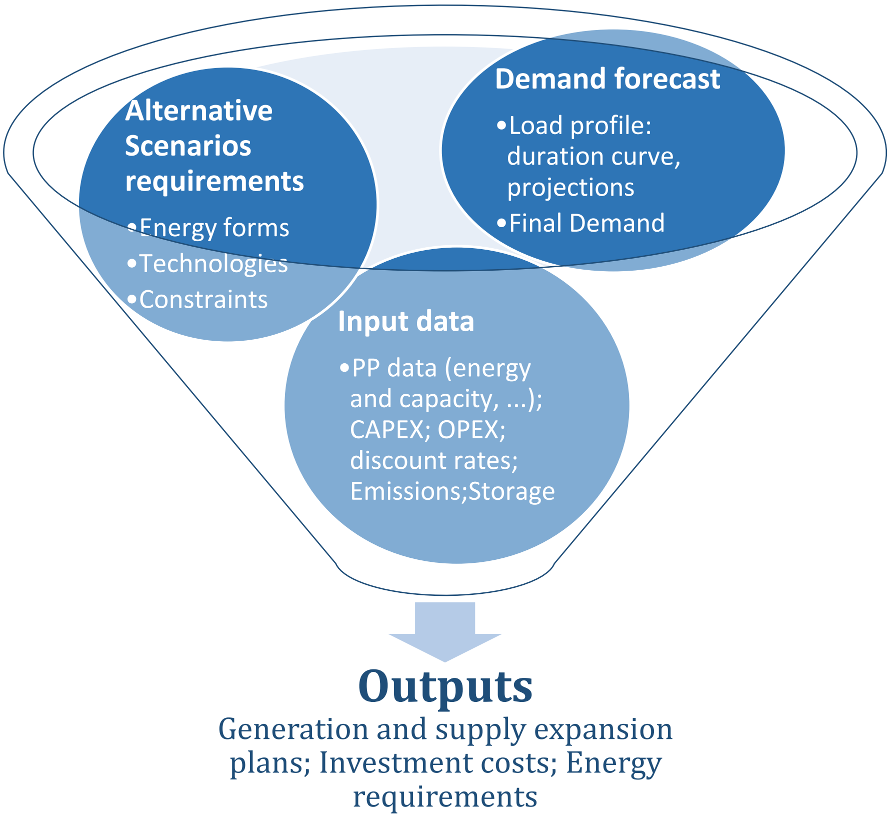

Figure 6: Processes in MESSAGE

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 4 and 5 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 4: Summary description of studied scenarios

ID	SCENARIO NAME	KEY SUPPLY CONSIDERATIONS/MAIN FEATURES
1	Reference Scenario (Business As Usual)	• Demand growth: 8.6% annually till 2035, and 5% afterwards • All existing PPAs and commitments by the GoR on upcoming PP, and projects in the pipeline • Solar PV integrating storage, Imports & Exports are restricted imports to 75 MW (including 58.1 MW currently), and exports to 30 MW throughout 2050 respectively
2	Domestic Generation	• Demand growth: 10% annually by 2030, and 5% afterwards. • All existing PPAs and commitments by the GoR on upcoming PP, and projects in the pipeline. • Domestic production, restricting Imports & Exports.
3	Power Trade & Interconnections	• Demand growth: 10% annually by 2030, and 5% afterwards. • 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.
4	Renewables	• Demand growth: 10% annually by 2030, and 5% afterwards. • All existing PPAs and commitments by the GoR on upcoming PP, and projects in the pipeline. • Supply restricted to Renewable technologies for upcoming PPs and projects in the pipeline.

For each supply-side scenario presented above, sensitivity is conducted with a high demand growth scenario of 10% annual growth throughout the horizon is modelled and tested (Scenarios 5-8) and the key results are presented in table 5.

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. We use the *High Demand Growth* case to study the requirements of an accelerated growing demand on electricity supply generation, especially after 2030.

Table 5 below presents a summary comparison of different scenarios for selected key metrics to guide the understanding of the implications of different expansion paths.

Table 5: Summary comparison of various studied scenarios[18]

Metric/Indicator		Reference Scenario (Business As Usual)		Domestic Generation		Power Trade & Interconnections		Renewables	
		Δ (10%, 5% after 2030)	10% Δ throughout	Δ (10%, 5% after 2030)	10% Δ throughout	Δ (10%, 5% after 2030)	10% Δ throughout	Δ (10%, 5% after 2030)	10% Δ throughout
Installed Capacity (MW)	2030	547	562	560	557	553	547	585	547
	2050	1494	3270	1539	3093	1518	3250	1331	3194
Total Demand (GWh)	2030	2,489	2,186	2,477	2,300	2,477	2,312	2,602	2,312
	2050	6,540	16,627	6,797	16,822	6,539	15,897	6,977	14,953
Imports (GWh)	2030	197	32	0	0	6	197	6	197
	2050	460	547	0	0	388	1678	6	197
Renewable energy share (%)	2030	72.7%	78.4%	70.0%	75.0%	69.1%	74.1%	71.1%	78.5%
	2050	63.2%	64.7%	61.4%	61.1%	84.5%	67.8%	73.1%	71.4%
Exports (GWh)	2030	17.89	9.13	0	0	17.89	17.89	0.37	17.89
	2050	17.89	9.13	0	0	35.41	44.17	0.37	44.17
Total Discounted Cost of Energy Supply (USD M)	2050	4,030.4	4,768.4	3,982.5	4,775.7	3,980.9	4,759.5	4,081.3	4,807.7
Expansion scenario costs relative to the Ref. scenario and the least cost scenario (USD M)		N/A 49.52	737.92 787.44	-47.94 1.58	745.2 794.74	-49.52 0	729.07 778.59	50.89 100.41	777.26 826.78
Peak Demand (MW)	2030	397	397	397	397	397	397	397	397
	2050	1053	2670	1053	2670	1053	2670	1053	2670

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.

[18] 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. June 2023 Assumptions & Updates

7.1. Assumptions:

Reference scenario key features:

I. Demand forecast: 10% throughout 2030, and 5% afterwards.

II. Power trade/Interconnection throughout 2050:
   a. Electricity import of up to 75 MW
   b. Export of up to 30 MW.

III. Introduction of renewable technologies 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. Wind generation.

IV. Phasing off thermal (diesel fired PPs) based on BAS (national decarbonisation pathways, and economic dispatching), but retaining ≤ 30 MW for emergency use.

7.2. Updates:

- Update and realignment of CODs of power plants[19]
- Model base year revised to 2022, with projections throughout 2050
- Updated demand assumptions/inputs (informed by Demand Analysis, (MAED, 2022) inputs and 5th RPHC Census key results)
- Consideration for utility-scale battery energy storages systems.
- Solar PV systems integrating storage.
- Integration of Generation Resource Assessment
    a. 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.
    b. Generic distributed wind generation
- Generic green hydrogen generation technology

[19] Nyabarongo_2 (CoD to 2027), Rusizi III (CoD to 2029), Nyirahindwe I & II (2024), Nyundo (2027/8), Base I (2025), Base II (2026), Rwondo & Ngororero (2026). This includes also addition of recently secured 40 MW imports through The Northern Interconnector: 220kV line Mirama (Uganda)-Shango (Rwanda).

8. Results

8.1. Installed Capacity and Peak Demand under Reference scenario

2023 – 2028

Figure 7 shows the total installed capacity over the next 5 years.

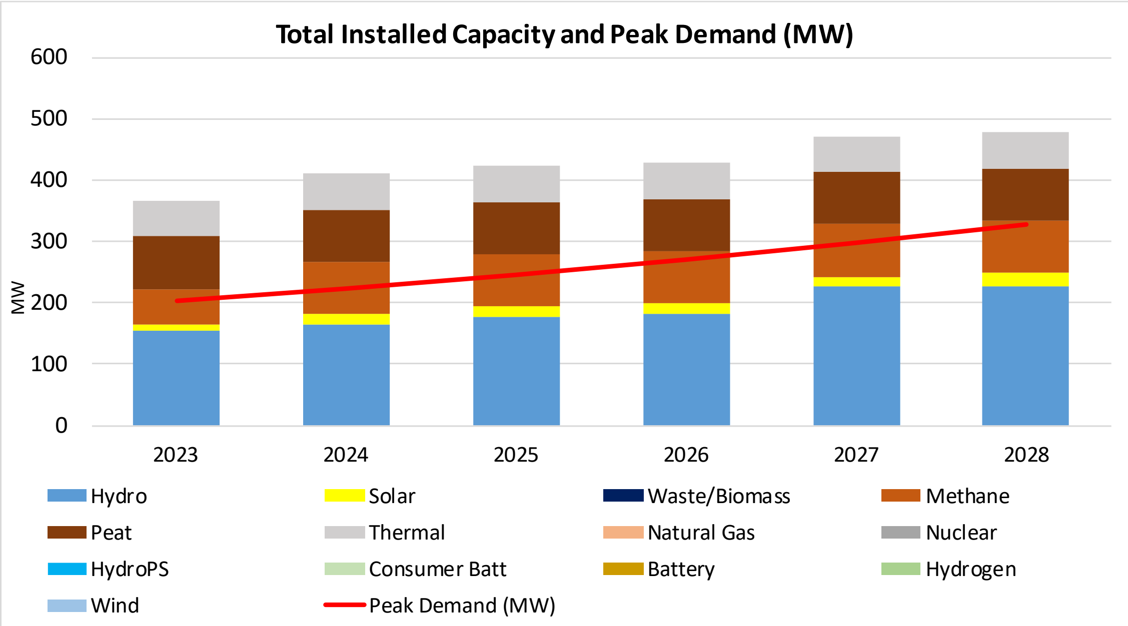

Figure 7: Total installed capacity (MW) in the near term 2023-2028

- The installed capacity and committed generation projects in the short term 2023-2028 is enough to satisfy the annual growing demand and reserve margin requirement.
- No additional imports beyond this year, as there is more than enough domestic capacity to satisfy the existing national demand, but wheeling through regional interconnection might change this pattern.
- Total installed capacity of thermal (diesel) powered plants remains at 28.80 MW[20] throughout the planning horizon.
- Excess capacity of about 30 MW exists that can be used for battery charge/discharge or for export adds to domestic demand and significantly increases potential company earnings.

2028 – 2050

Figure 8 shows the evolution of total installed capacity of generation supply technologies on the Rwandan grid.

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

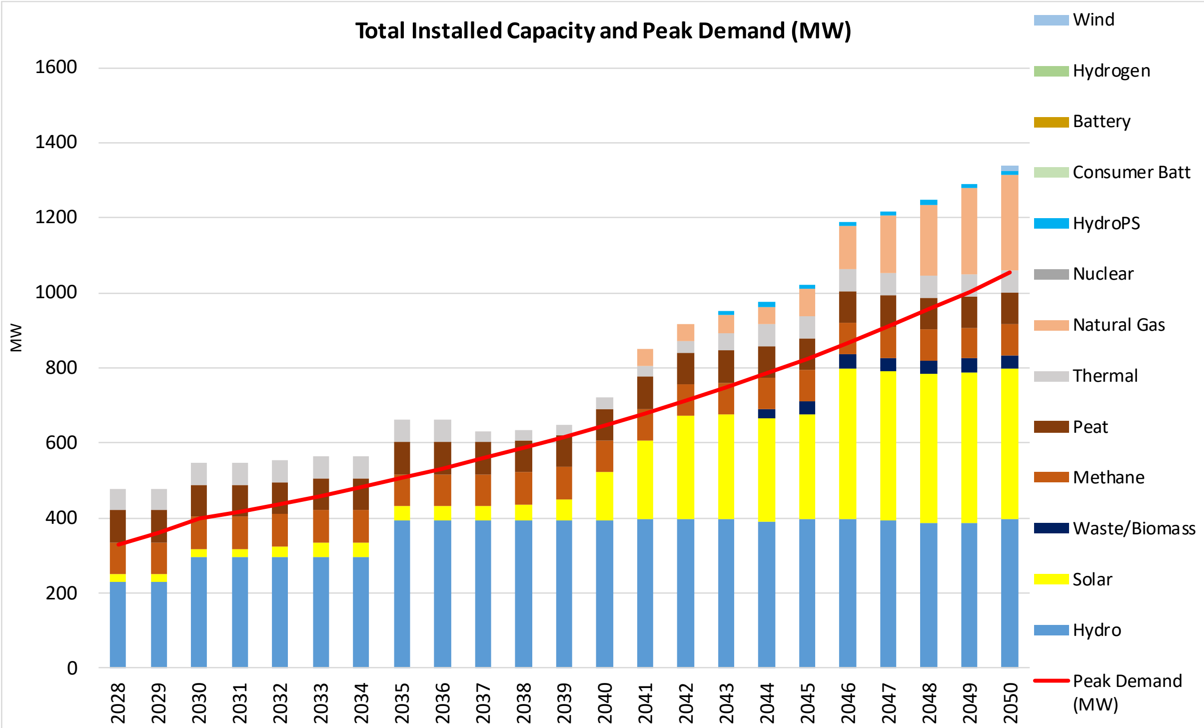

Figure 8: Total Installed Capacity (MW) in the longer term 2028 - 2050

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

i. Addition of 209 MW of natural gas installed capacity by 2050.
ii. Addition of 11 MW of hydro pumped storage by 2050.
iii. Addition of 408 MW of Solar PV.
iv. Addition of 37.8 MW of Waste to Power
v. Addition of 294.4 MW of Conventional Hydro Power
vi. Addition of 15 MW of wind to power.

Annual addition of installed capacity per technology is shown in *Table 6* below.

In addition to committer projects presented in Table 3, below we present technology specific additions in line with the least cost scenario.

Table 6: Annual Added Capacity (MW) per Technology Type

Year	POWER PLANT(S)	TECHNOLOGY ADDED	TOTAL CAPACITY ADDED (MW)
2027	Nyabarongo II (43.5 MW)	Hydro	43.5
2028	Committed Utility-Scale Solar PV (6 MW)	Solar	6
2029	Rusizi III (68 MW)	Hydro	68
2032	Generic Utility-Scale Solar PV (18 MW)	Solar	18
2035	Rusizi IV (95.9 MW)	Hydro	95.9
2038	Generic Utility-Scale Solar PV (28 MW)	Solar	28
2039	Generic Solar PV (120 MW)	Solar	120

Year	POWER PLANT(S)	TECHNOLOGY ADDED	TOTAL CAPACITY ADDED (MW)
2040	Generic Utility-Scale Solar PV (69 MW)	Solar	69
2041	Generic Utility-Scale Solar PV (83 MW)	Solar	83
2042	Generic Utility-Scale Solar PV (71 MW)	Solar	71
2043	Hydro pumped storage (11.16 MW) New Generic Thermal (37.8 MW)	Hydro PS Thermal	48
2044	Generic Waste to Power PP (37 MW)	Waste	37
2045	Generic Natural gas fired PP (70 MW)	Natural Gas	70
2046	Generic Utility-Scale Solar PV (124 MW)	Solar	124
2047	Generic Natural gas fired PP (73 MW)	Natural Gas	73
2048	Generic Utility-Scale Solar PV (9 MW)	Solar	9
2049	Generic Natural gas fired PP (66 MW)	Natural Gas	66
2050	Generic Wind to Power (15 MW)	Wind	15

8.2. Electricity Production & Demand:

Figure 9 and *Table 7* provide a 5-year time step of the annual production profiles of each technology type during this planning horizon.

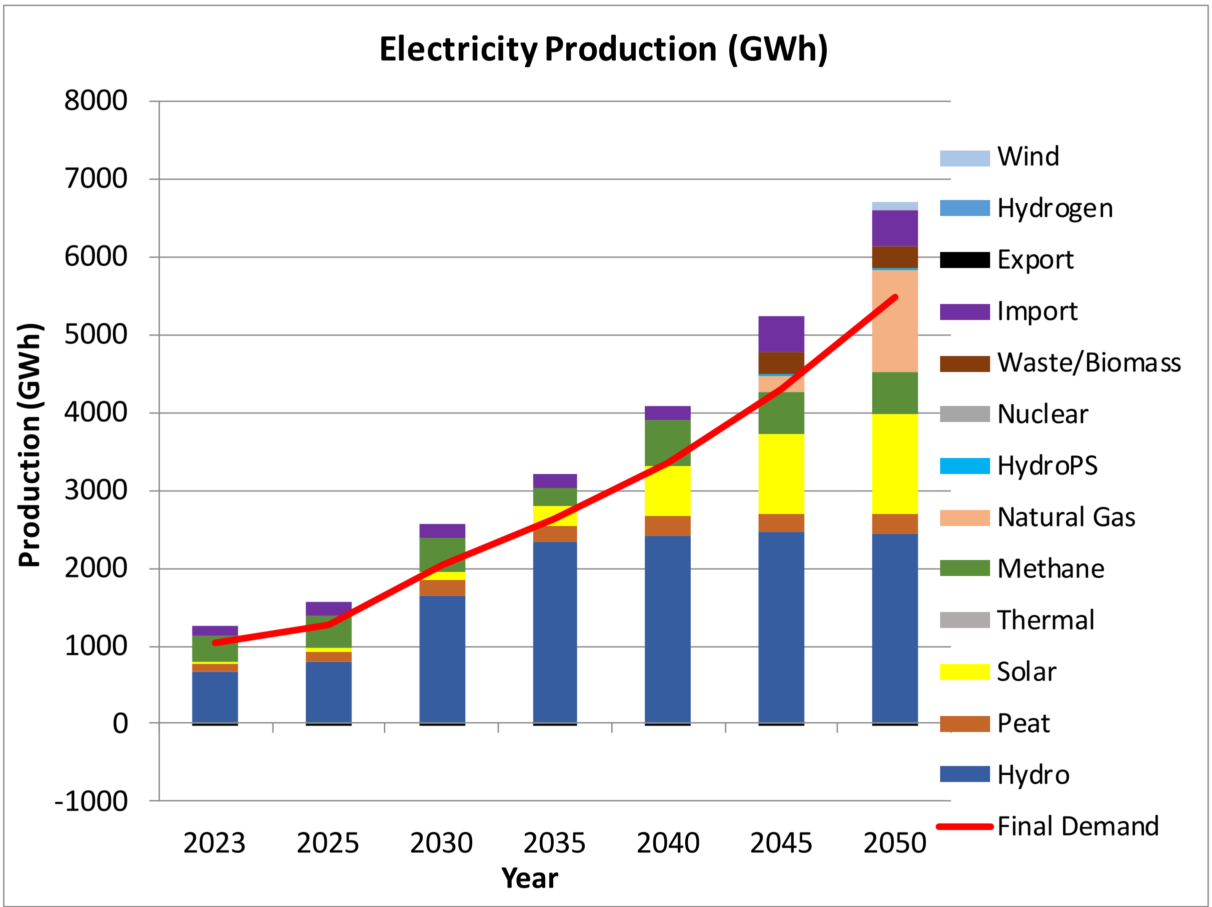

Figure 9: Production per Technology Type (GWh)

It is clear that hydro dominance persists throughout the planning horizon. Peat production also increases to satisfy the domestic demand. In addition, thermal requirements are eliminated. This is due to the least-cost selection of supply from imports within this time period. Production from hydro pumped storage begins and starts to contribute in the longer term, as installed capacity increases.

Table 7: Production (GWh) per Technology Type

Year	2023	2025	2030	2035	2040	2045	2050
Domestic Production	**1118.4**	**1390.4**	**2380.1**	**3026.7**	**3893.1**	**4772.2**	**6253.8**
Hydro	664.6	800.9	1,634.8	2,326.9	2,410.9	2,456.3	2,447.6
Solar	18.3	56.1	99.9	254.4	658.2	1,020.9	1,276.0
Waste/Biomass	-	-	-	-	-	278.6	278.6
Methane	330.6	410.5	435.8	235.6	573.5	546.7	546.7
Peat	104.9	122.8	209.7	209.7	250.4	250.4	250.4
Thermal	-	-	-	-	-	-	-
Natural Gas	-	-	-	-	-	194.8	1,324.8
Nuclear	-	-	-	-	-	-	-
HydroPS	-	-	-	-	-	24.4	24.4
Consumer Batt	-	-	-	-	-	-	-
Battery	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	105.1
Import/Export	**129.2**	**168.6**	**179.5**	**179.5**	**179.5**	**442.3**	**442.3**
Import	138.4	187.1	197.4	197.4	197.4	460.2	460.2
Export	(9.1)	(18.4)	(17.9)	(17.9)	(17.9)	(17.9)	(17.9)
Total Supply	**1247.7**	**1559.0**	**2559.7**	**3206.2**	**4072.6**	**5214.5**	**6696.1**
Grid Losses	**212.7**	**261.8**	**439.9**	**508.4**	**637.1**	**813.3**	**1040.5**
Transmission Losses	38.2	47.1	75.4	94.8	120.8	154.1	197.0
Distribution Losses	174.5	214.7	364.5	413.6	516.2	659.2	843.6
Final Demand	**1028.9**	**1266.0**	**2049.4**	**2627.5**	**3365.3**	**4297.2**	**5499.0**
Total Demand	**1241.6**	**1527.8**	**2489.3**	**3135.9**	**4002.3**	**5110.5**	**6539.5**

8.3. Renewable Energy Share (RES) in Total Power Production

Figure 10 below shows the renewable energy share (RES) in power production throughout the planning horizon. The ESSP targets set were met during this time horizon.

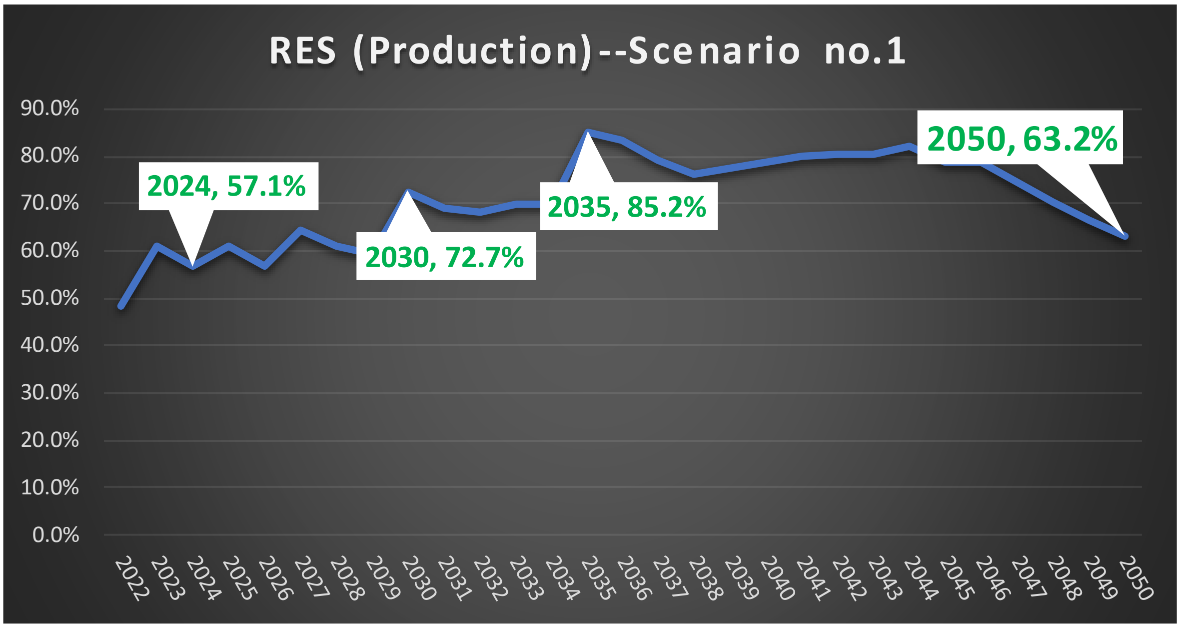

Figure 10: RES in Power Production (%)

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. This is taken into account in the planning stage as the proposed expansion is selective based on cleaner sources of power, some of which are not renewable.

9. Climate Change & Impact on Hydropower Production[21]

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.

[21] 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.

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 8* 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)[22], which is planned to begin operations towards the end of 2023, and the Nyundo Hydropower Plant (4.5 MW) which is scheduled for commissioning in 2027/8.

Figure 11 presents a map with the eight power plants and their corresponding sub-basins which have been calculated using ArcGIS and its hydrology tools.

Table 8: 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
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	Planned	2023

[22] 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.

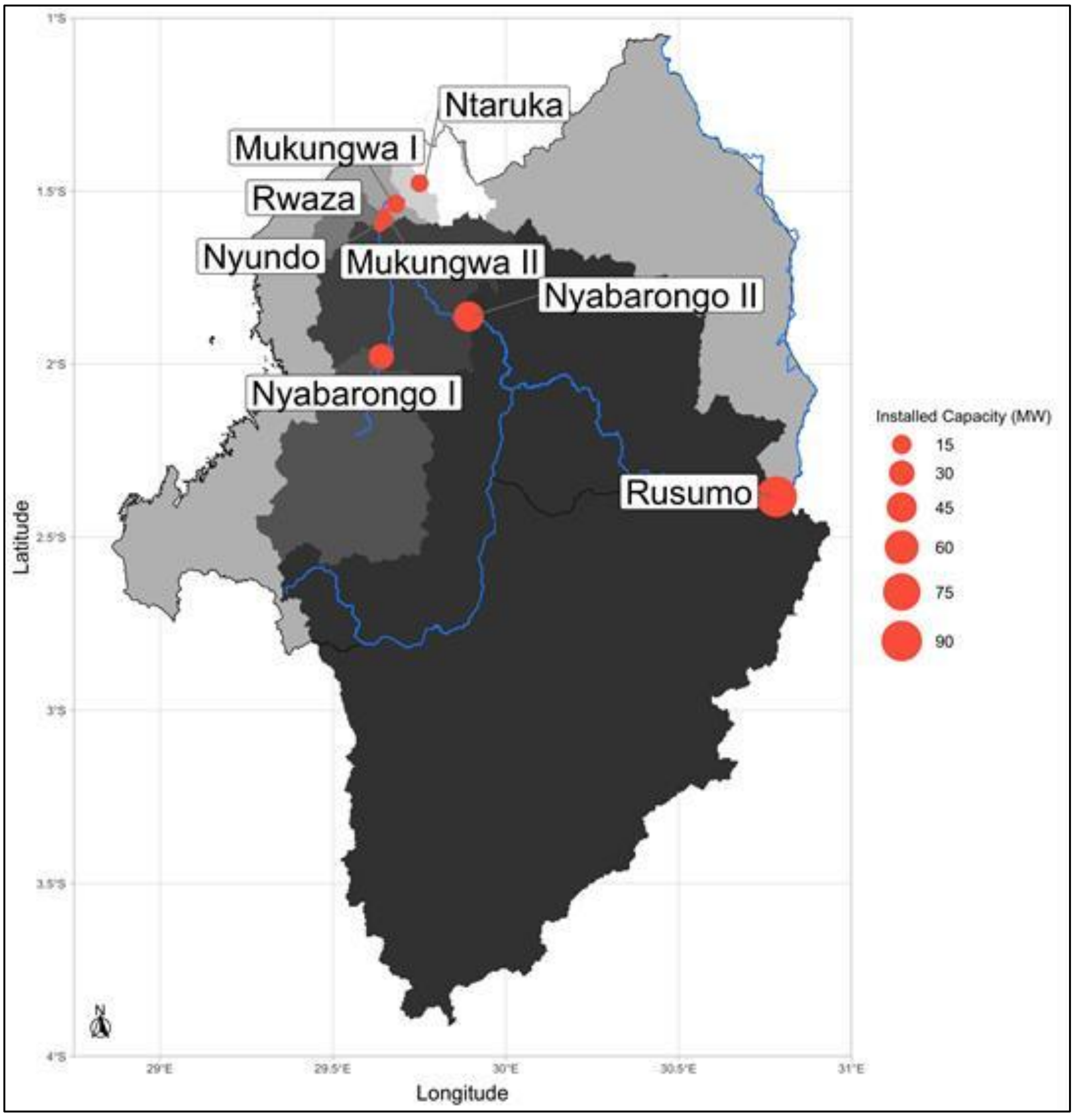

Figure 11: HPPs in Rwanda under analysis (different Climate Models and Climate Scenarios)

For all of these power plants climate projections and historical experiments have been obtained from the NASA's Earth Exchange Global Daily Downscaled Projections Dataset (NEX-GDDP). The initial analysis was performed using the inputs from 21 general circulation models (GCMs) under two different emission scenarios. *Table 9* presents the list with the names of the 21 GCMs used.

The emission scenarios analysed include representative concentration pathways (RCPs) 4.5 and 8.5. RCP 4.5 represents a mid-emissions scenario, in which greenhouse gas concentrations in the atmosphere peak around 2040 and decline after that. On the other hand, RCP 8.5 presents a business-as-usual scenario, in which greenhouse gas atmospheric concentrations continue to increase throughout the century. The calibration of the model was performed using the GRUN dataset, which provides a reconstruction of global runoff from 1902 to 2014.

Table 9: General Circulation Models (GCM) obtained from NASA's NEX-GDDP dataset and Used for Streamflow analysis

Global Climate Models
INCM4.0
BCC-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[23]. 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:

$$Q_t = S_{t-1} + P_t - AET_t - S_t$$

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.

[23] 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

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[24] 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 we were able 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 12-18 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.

[24] 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.

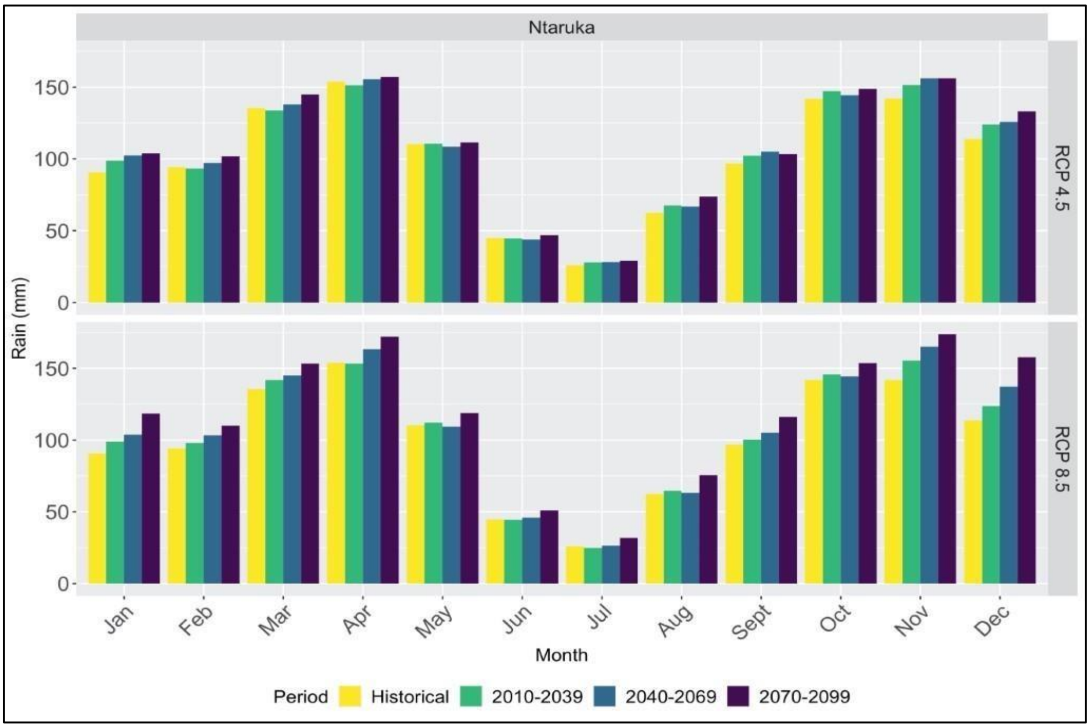

Figure 12: Average Multi-Model Precipitation (mm) for the Ntaruka Sub-basin.

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.

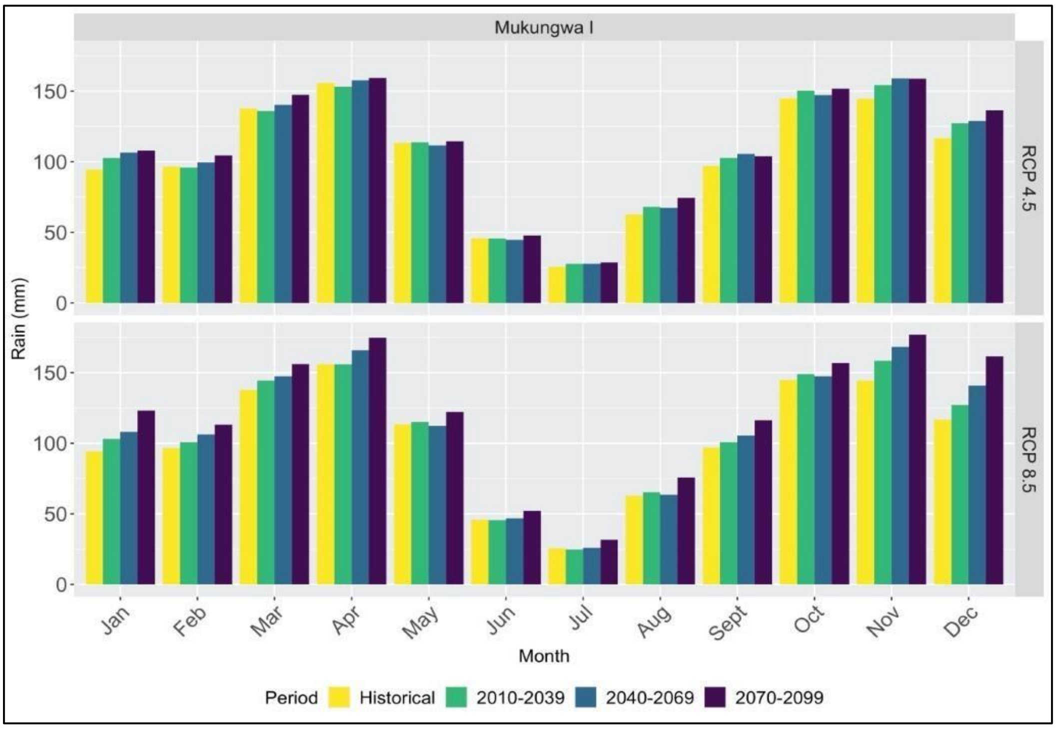

Figure 13: Average Multi-Model Precipitation (mm) for the Mukungwa I Sub-basin.

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.

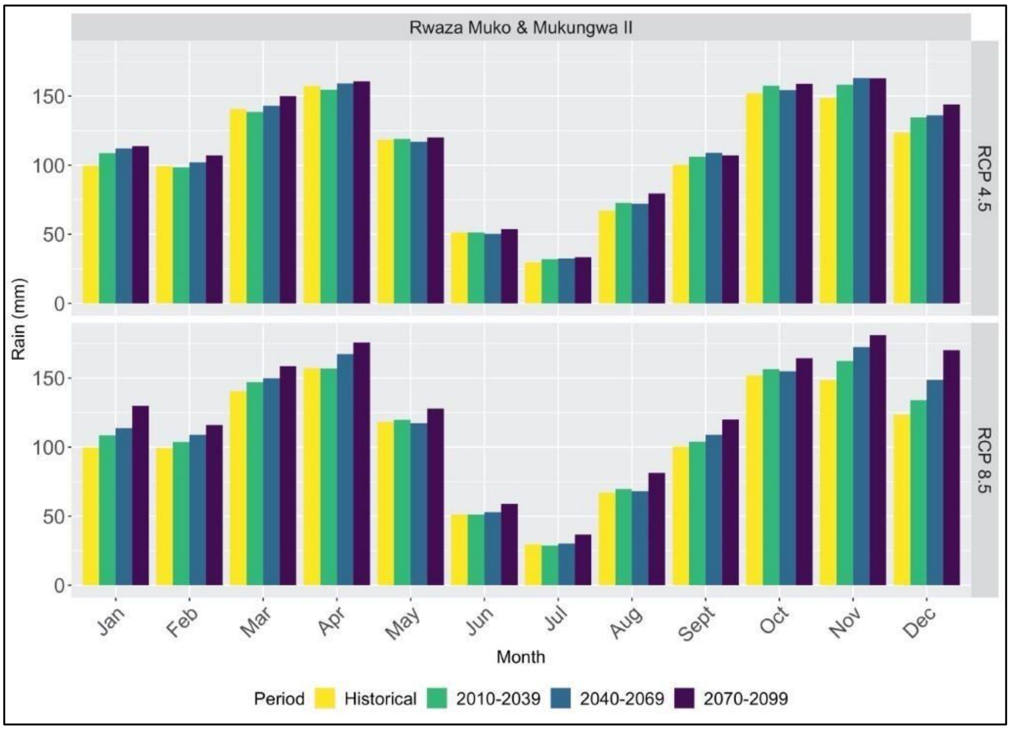

Figure 14: Average Multi-Model Precipitation (mm) for the Rwaza-Muko/Mukungwa II Sub-basin.

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.

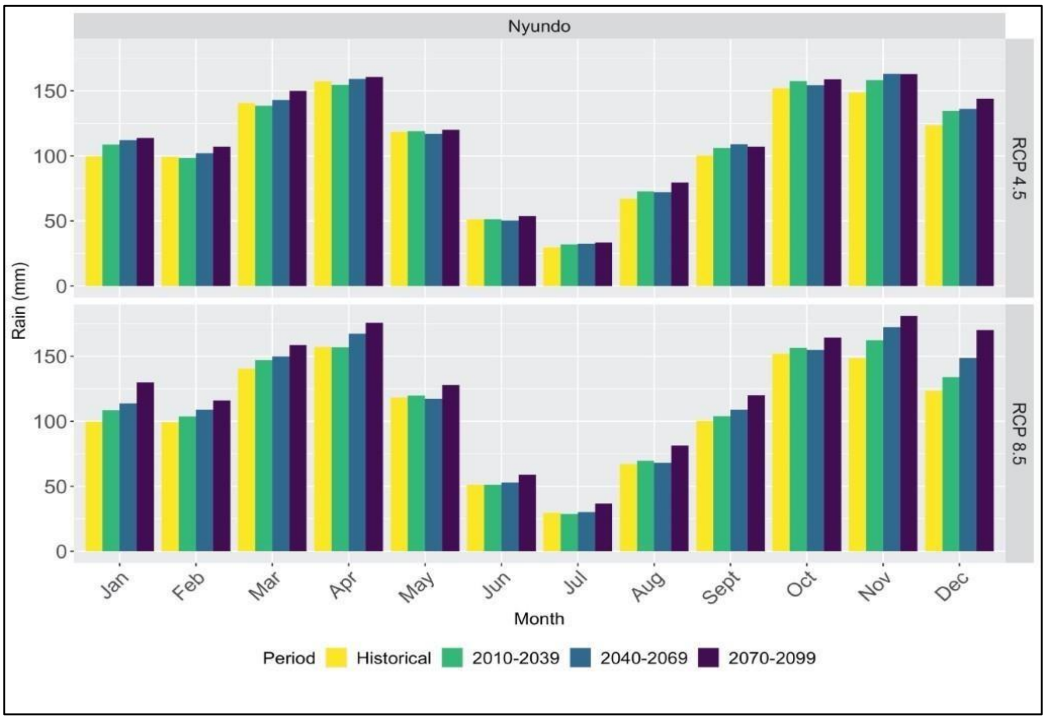

Figure 15: Average Multi-Model Precipitation (mm) for the Nyundo Sub-basin.

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.

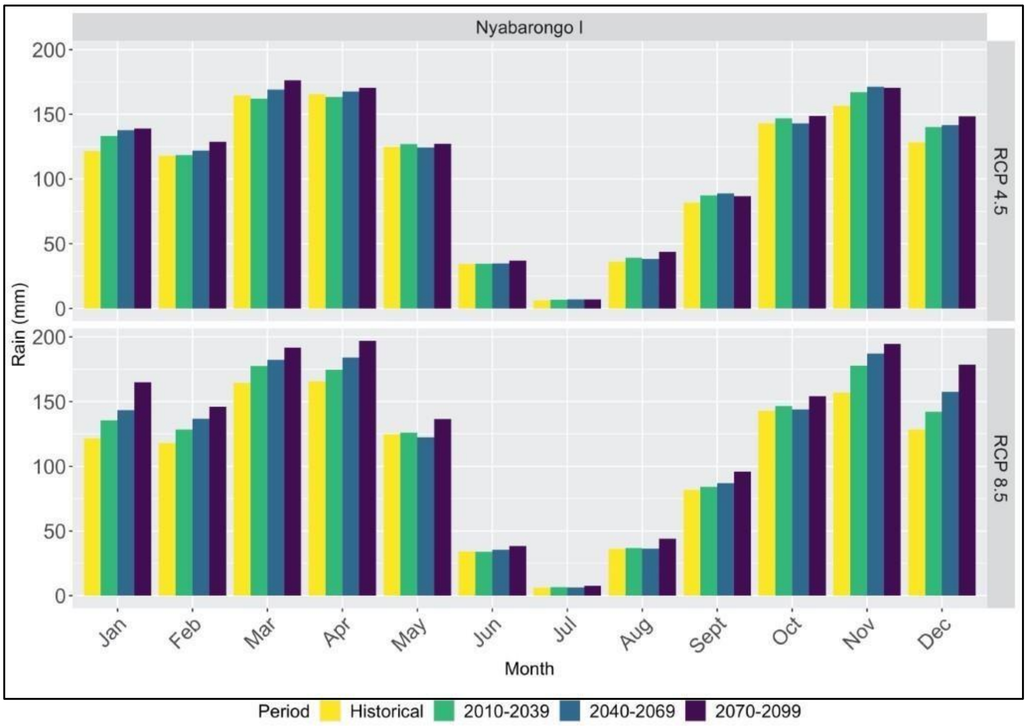

Figure 16: Average Multi-Model Precipitation (mm) for the Nyabarongo I Sub-basin.

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.

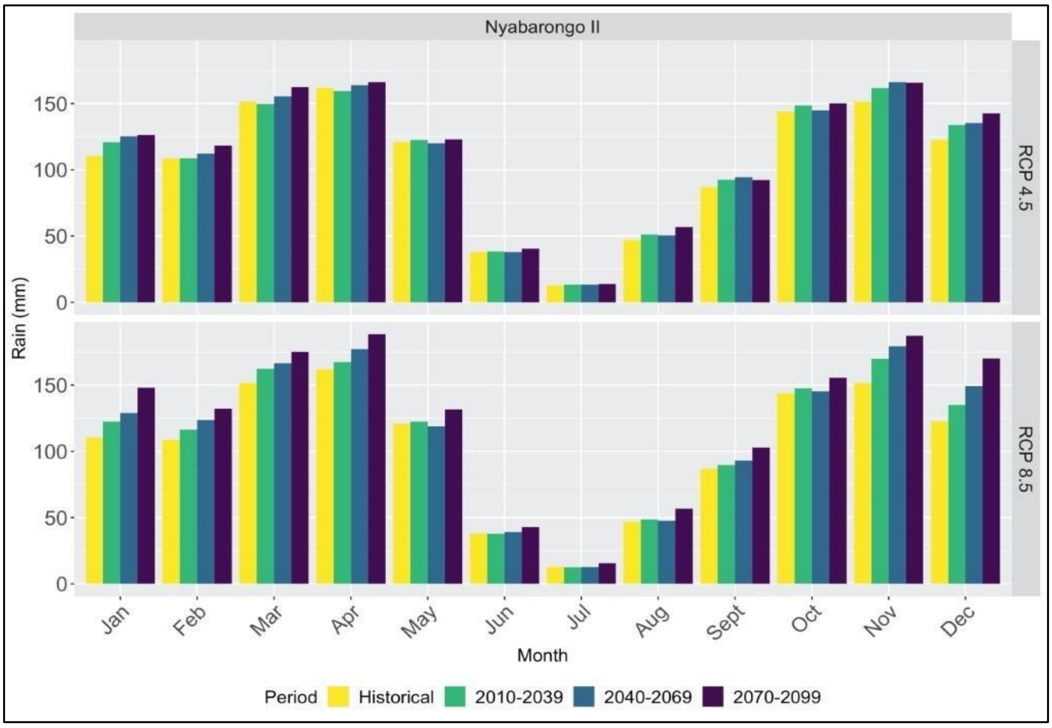

Figure 17: Average Multi-Model Precipitation (mm) for the Nyabarongo II Sub-basin.

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.

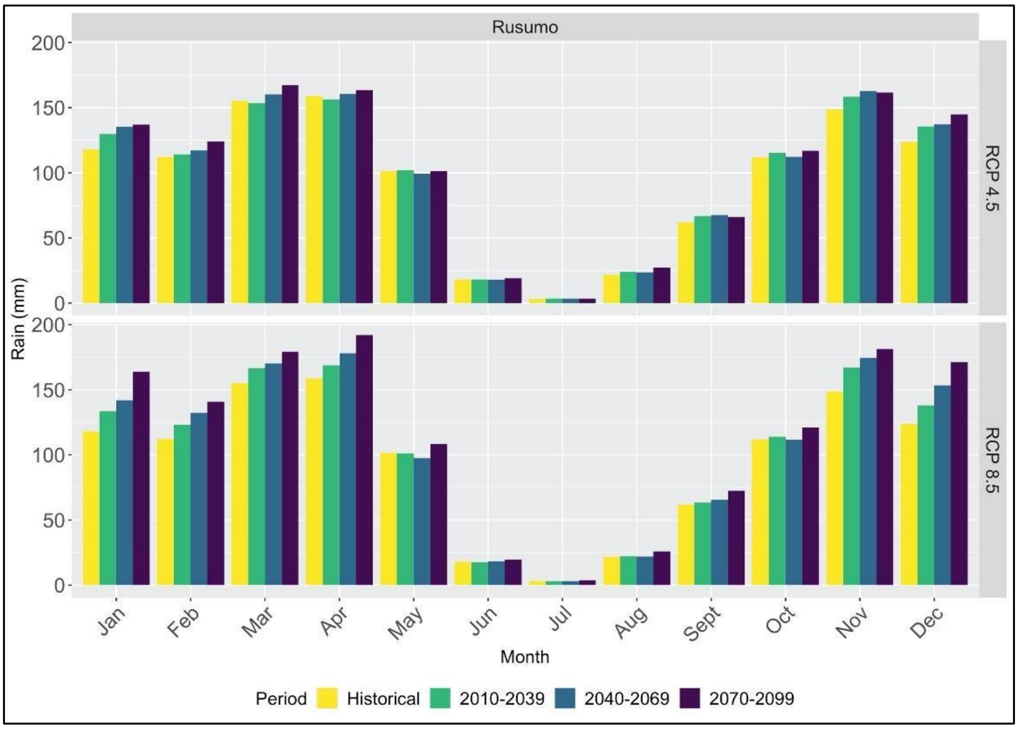

Figure 18: Average Multi-Model Precipitation (mm) for the Rusumo Sub-basin.

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 19 - 25 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.

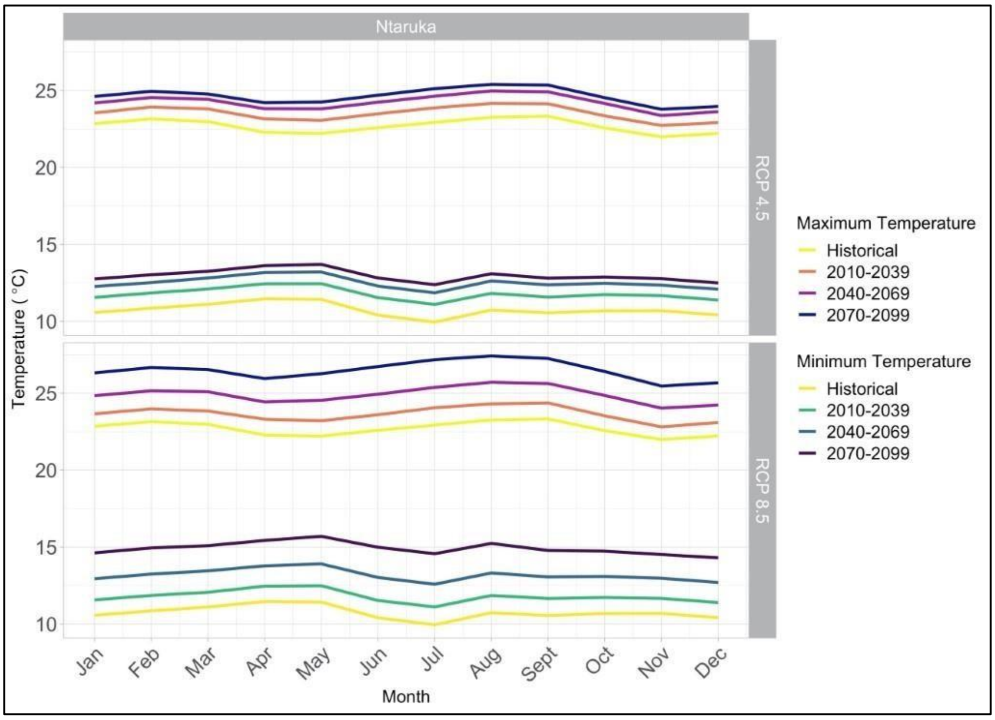

Figure 19: Changes in Minimum and Maximum Temperature (°C) for the Ntaruka Subbasin.

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

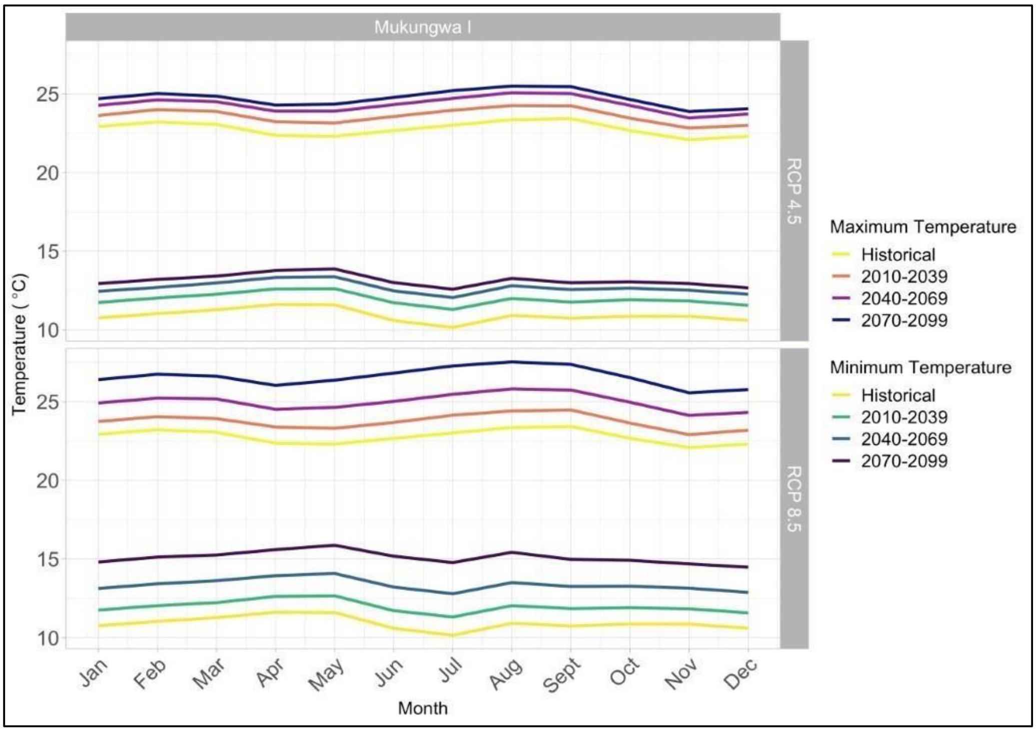

Figure 20: Changes in Minimum and Maximum Temperature (°C) for the Mukungwa I Sub-basin.

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.

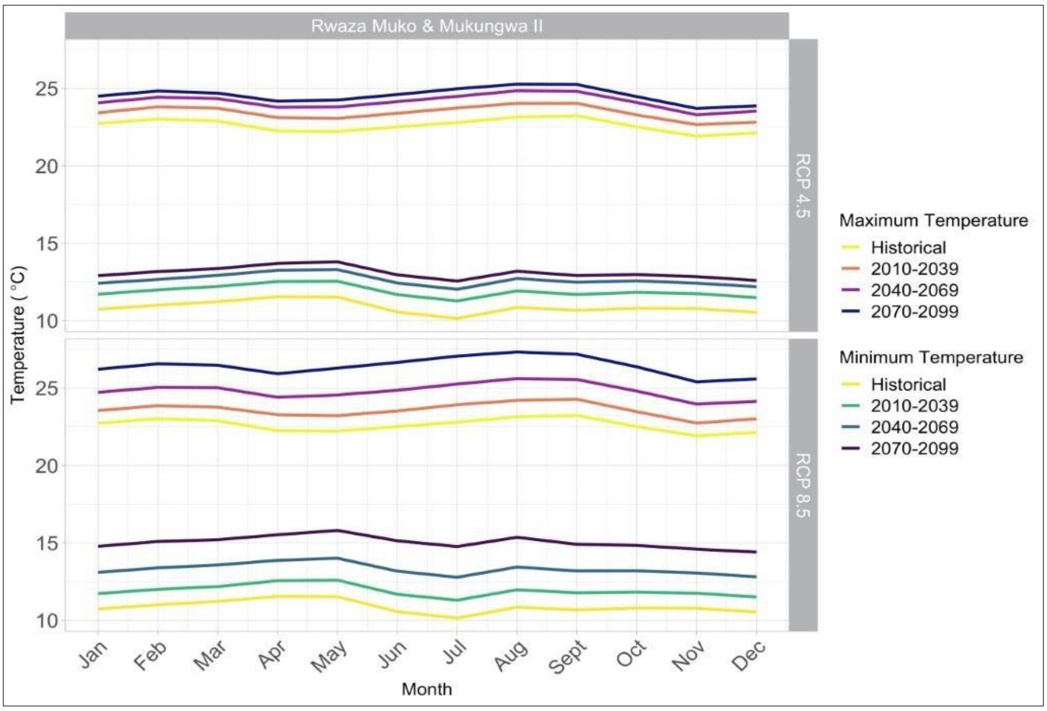

Figure 21: Changes in Minimum and Maximum Temperature (°C) for the Rwaza Muko/Mukungwa II Sub-basin.

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.

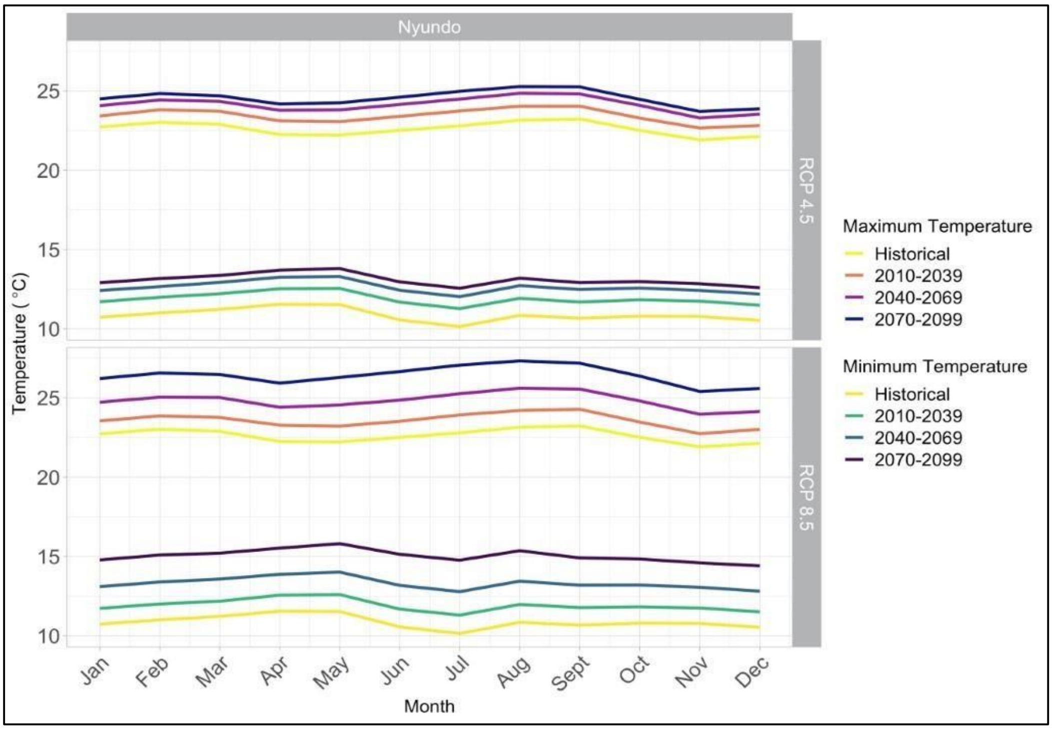

Figure 22: Changes in Minimum and Maximum Temperature (°C) for the Nyundo Subbasin.

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

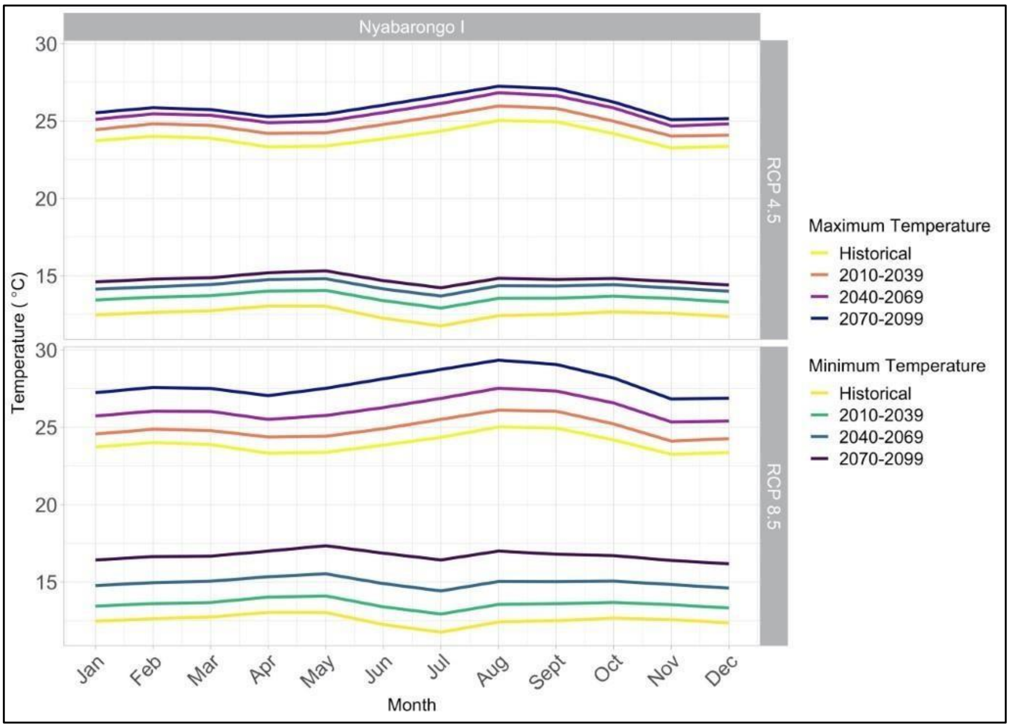

Figure 23: Changes in Minimum and Maximum Temperature (°C) for the Nyabarongo I Sub-basin.

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.

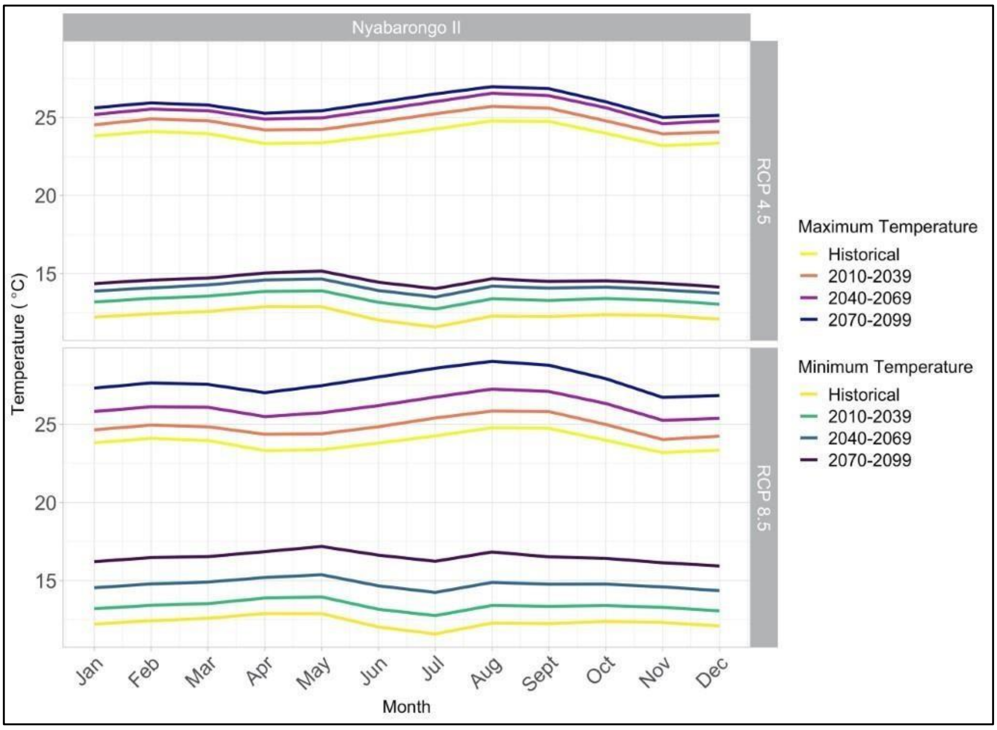

Figure 24: Changes in Minimum and Maximum Temperature (°C) for the Nyabarongo II Sub-basin.

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.

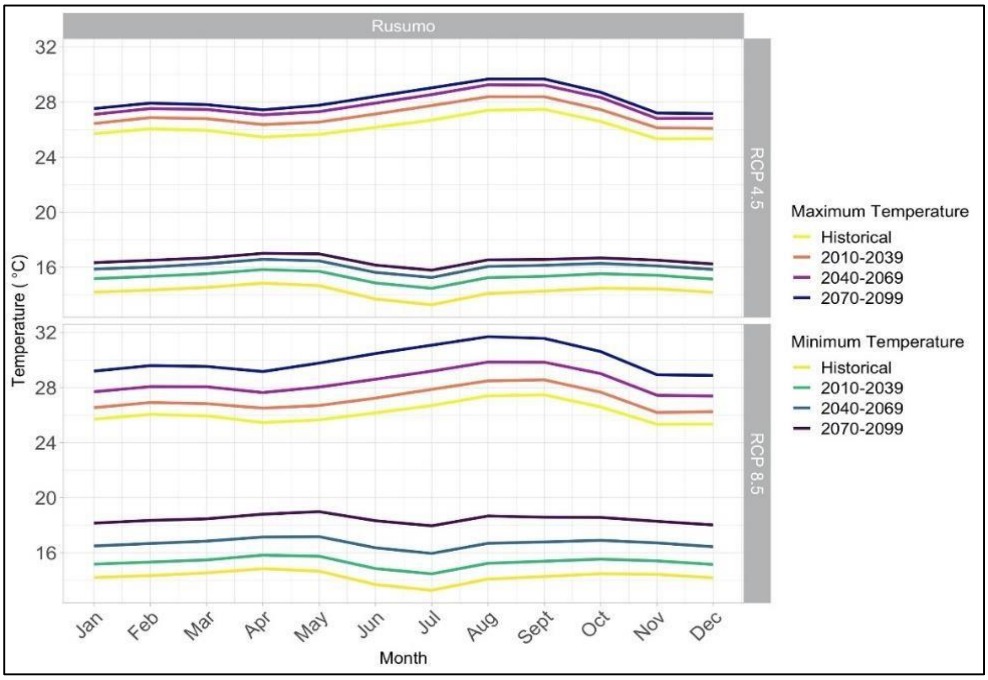

Figure 25: Changes in Minimum and Maximum Temperature (°C) for the Rusumo Subbasin.

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.

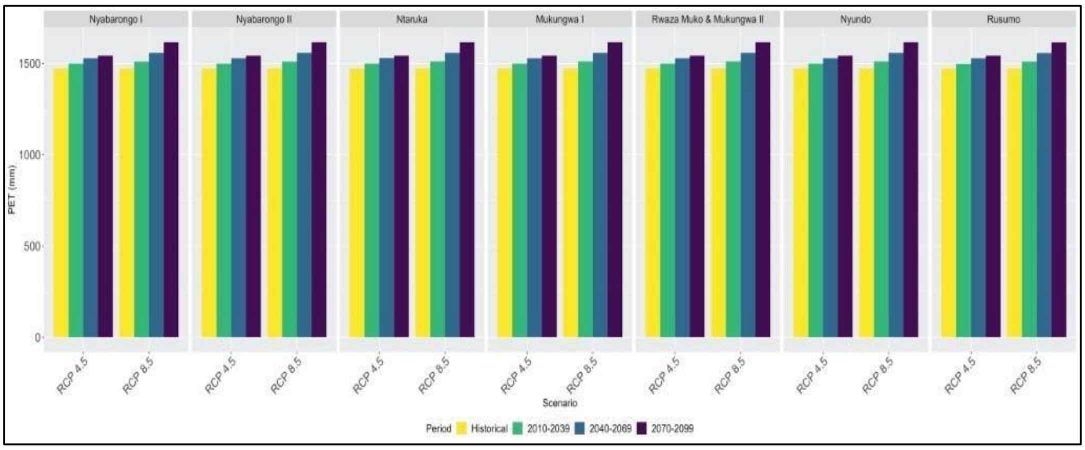

Figure 26: Changes in Potential Evapotranspiration (Hargreaves Method).

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.

9.3. Streamflow & Available Capacity[25]

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 27 - 33* present the average monthly results from the multi-model ensemble.

[25] 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

Overall, there are increases in streamflow for all sub-basins which can be seen in greater detail in *Tables 10, 11*, and *12*. These tables presents results for the low streamflow (10^{th} percentile), median streamflow (50^{th} percentile), and high streamflow (90^{th} percentile). The changes in projected flow encompass all the results from the 21 GCMs.

Tables 10, 11, and *12*[26] present the results for the three cases respectively: *low flow*, *median flow* and *high flow*.

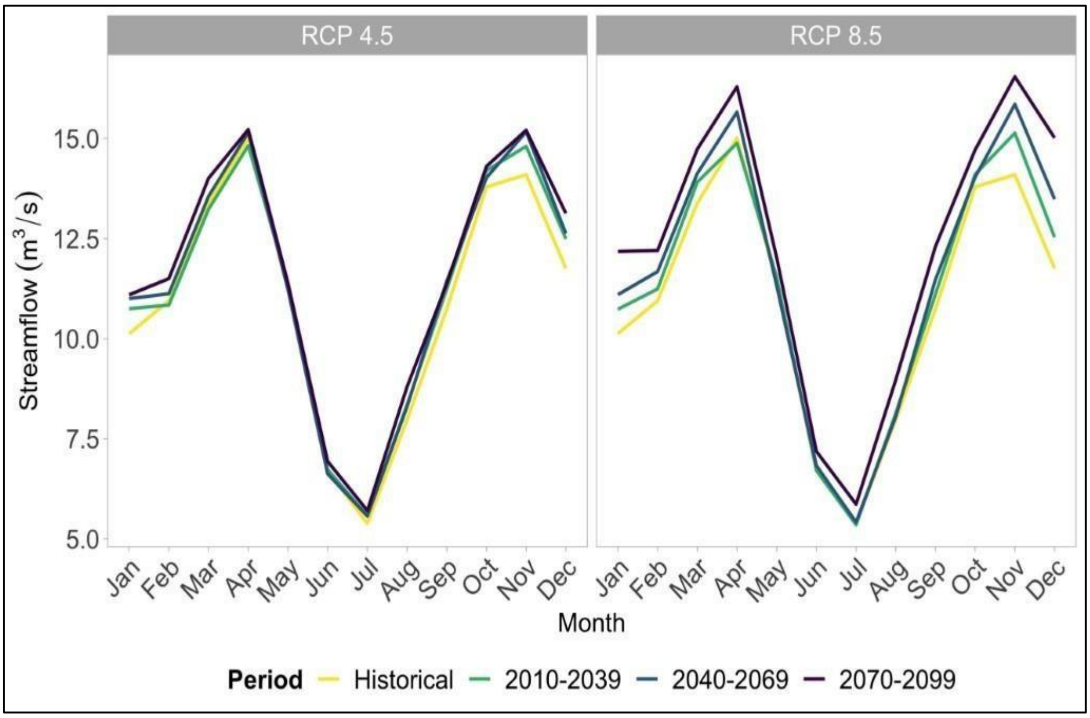

Figure 27: Average monthly streamflow from the multi-model ensemble for the Ntaruka subbasin

[26] These results present naturalized streamflow without considering water demand within the basin.

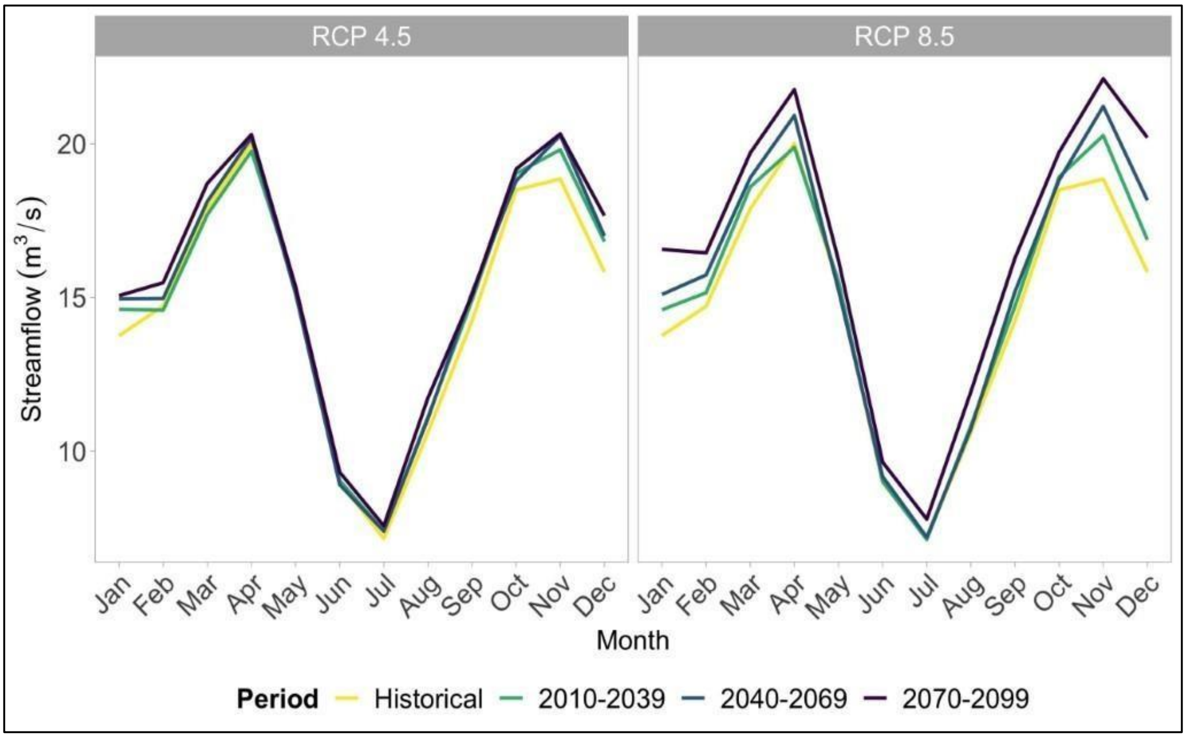

Figure 28: Average monthly streamflow from the multi-model ensemble for the Mukungwa I sub-basin

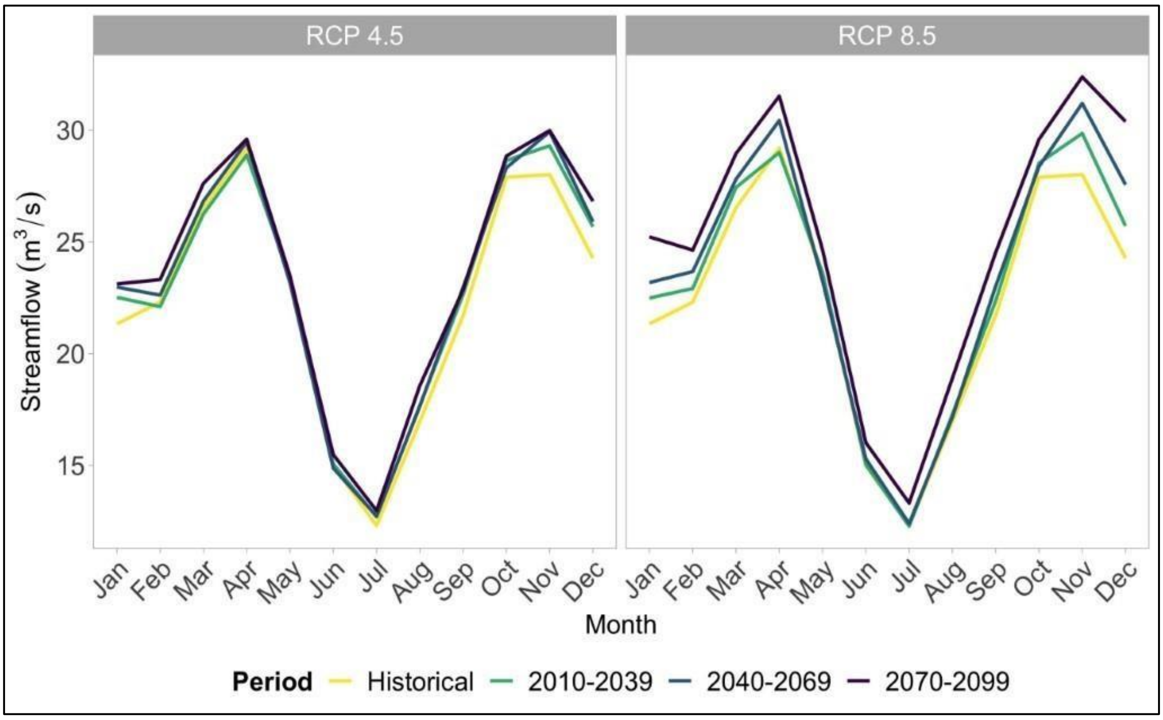

Figure 29: Average monthly streamflow from the multi-model ensemble for the Rwaza-Muko/Mukungwa II sub-basin

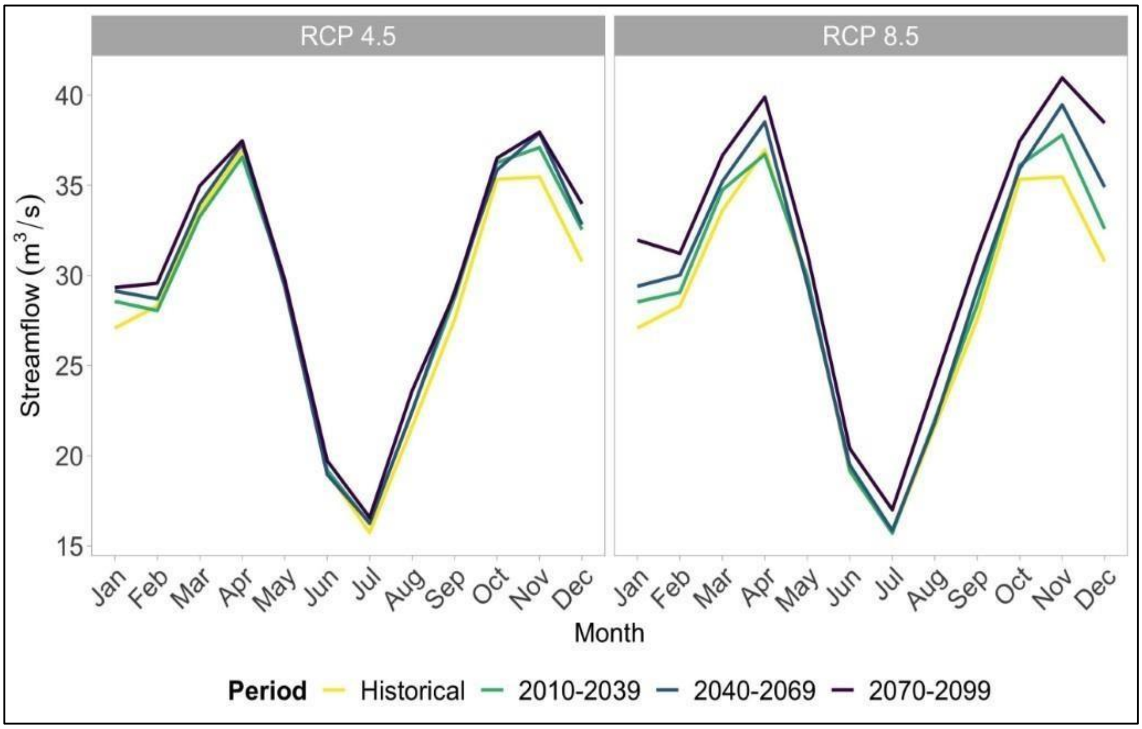

Figure 30: Average monthly streamflow from the multi-model ensemble for the Nyundo sub-basin.

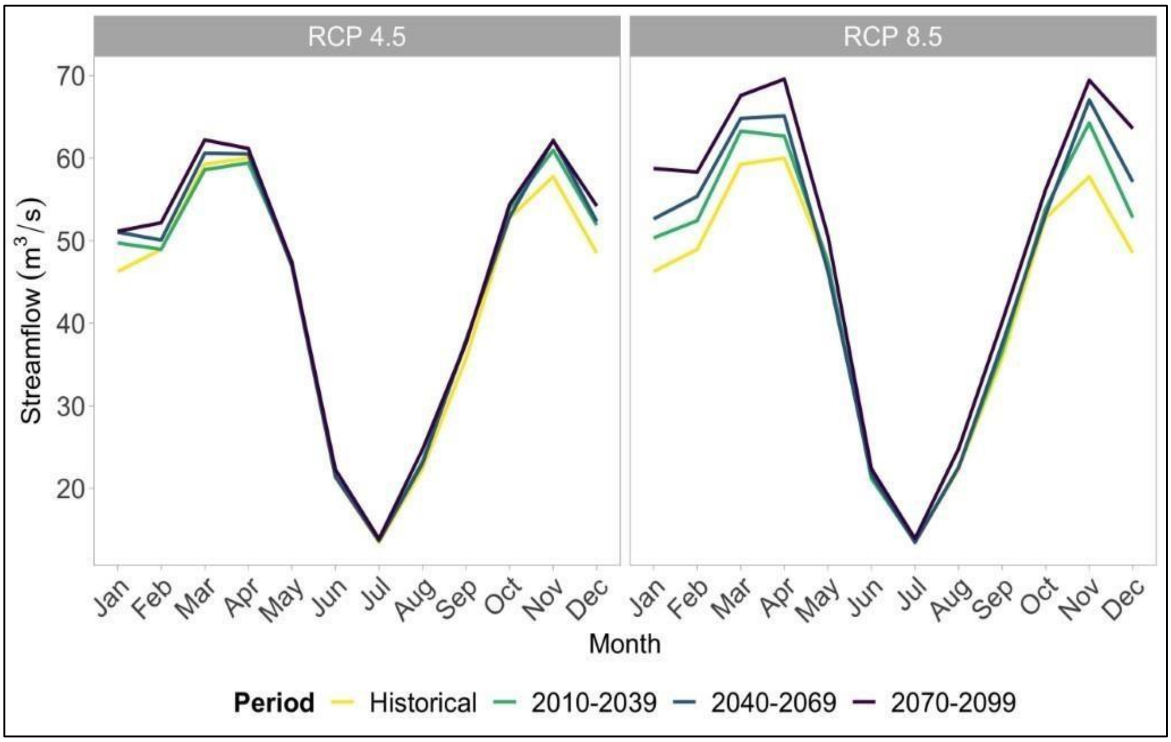

Figure 31: Average monthly streamflow from the multi-model ensemble for the Nyabarongo I sub-basin.

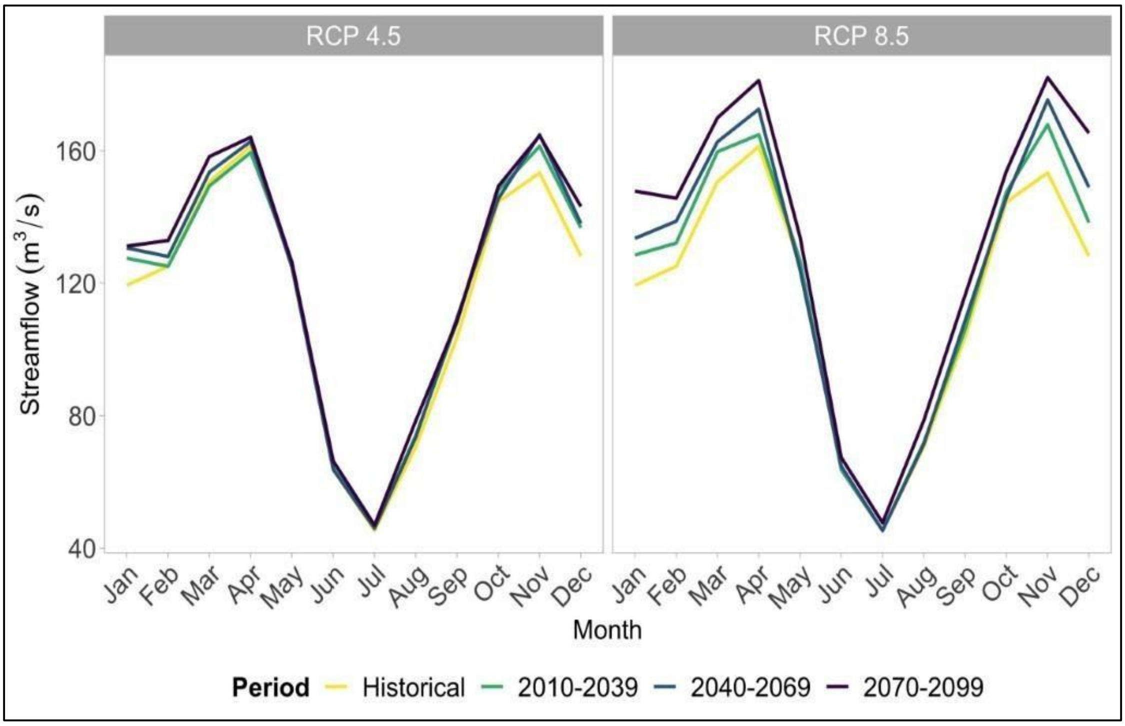

Figure 32: Average monthly streamflow from the multi-model ensemble for the Nyabarongo II sub-basin.

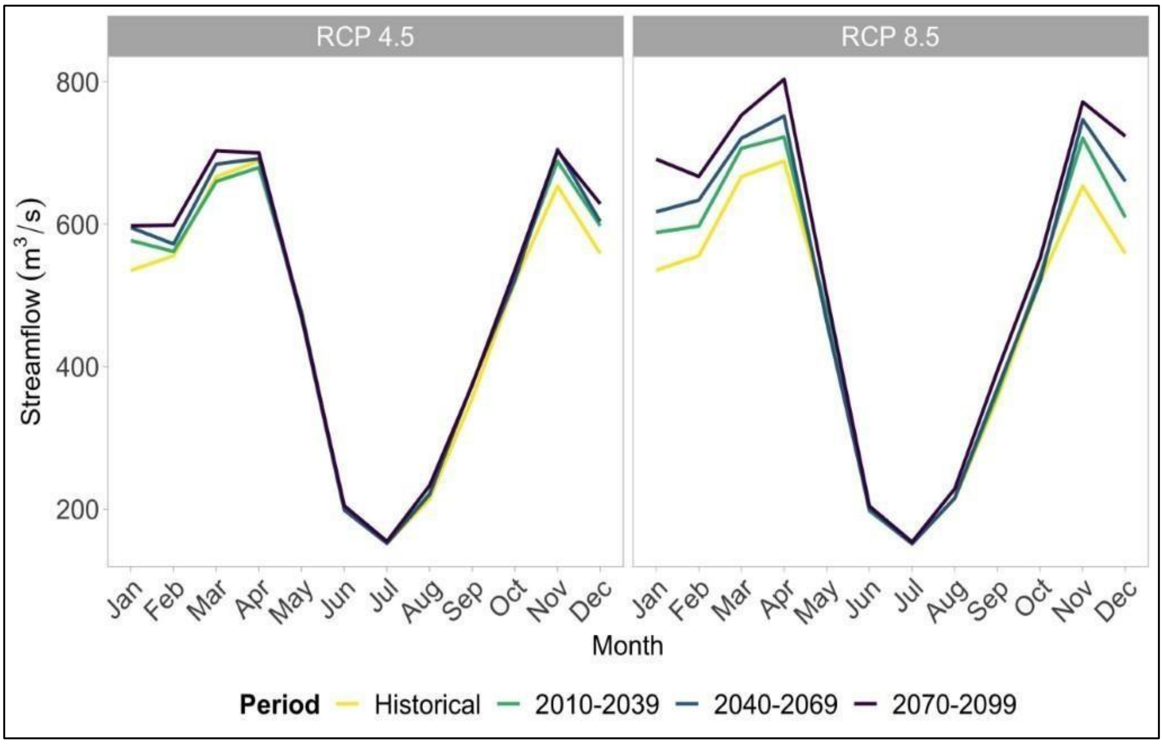

Figure 33: Average monthly streamflow from the multi-model ensemble for the Rusumo sub-basin

Table 10: 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 11: 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 12: 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 we go 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 34 and 35 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*.

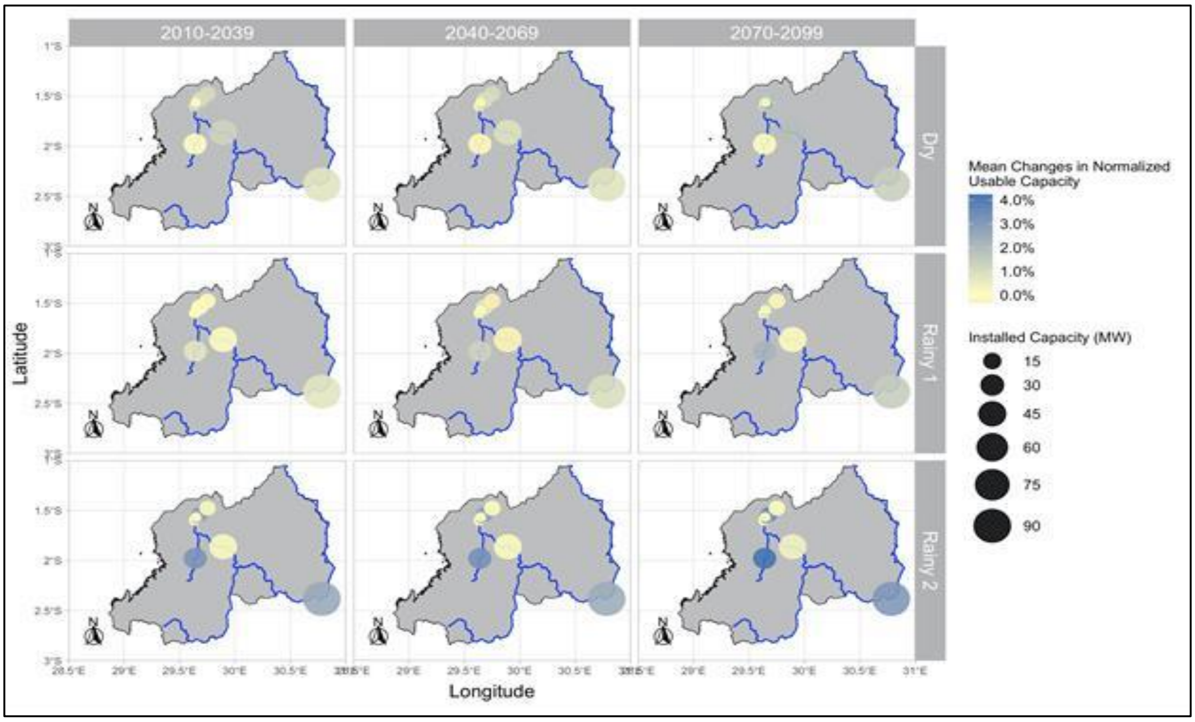

Figure 34: Rwanda's mean relative changes in normalized available capacity for RCP 4.5.

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).

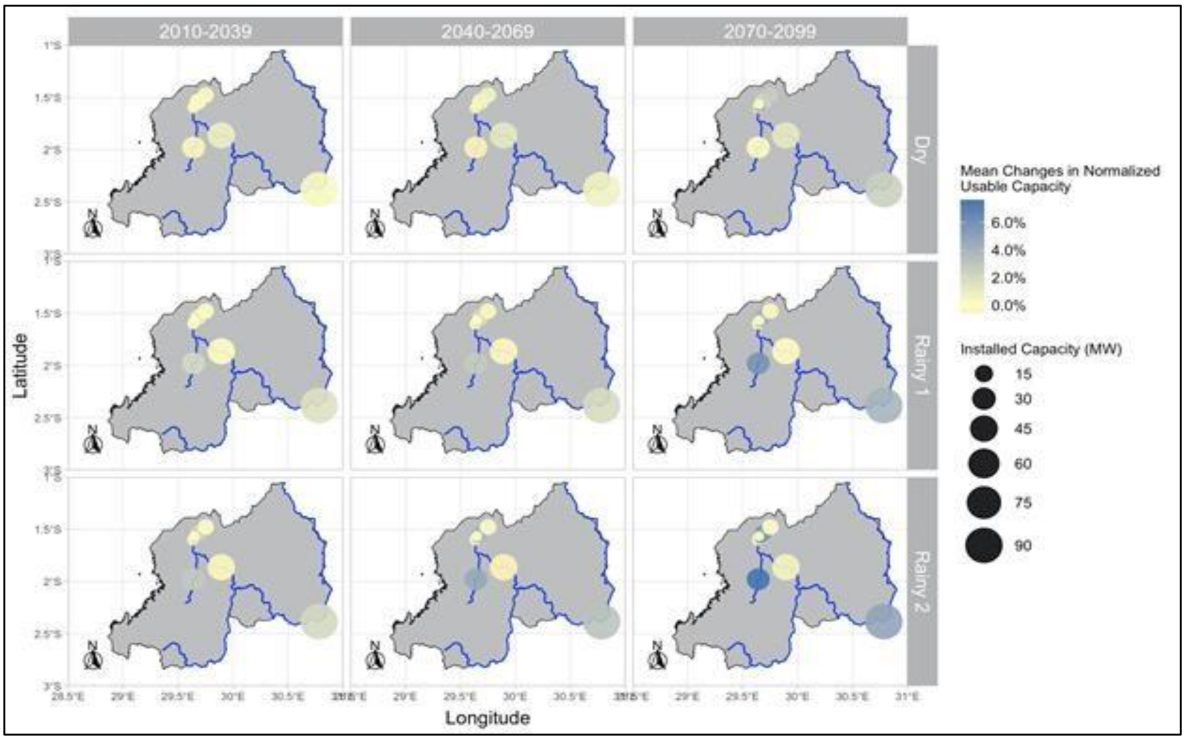

Figure 35: Rwanda's mean relative changes in normalized available capacity for RCP 8.5.

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 of 10% annual growth, this is in part due to the effect of Covid-19 that saw 2.2% growth in the year 2020, but prospects of recovery are slowly coming in sight with 12.3% and 12.5% growth realised in 2021 and 2022 respectively, and a forecast growth of 8.9-10% in 2023[27]. Demand growth in the years ahead is also contingent to the timely materialization of flagship 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 export contract (***10 years or longer***) to neighbouring countries.

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.

[27] This is to be confirmed in the December 2023 update.

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 green electricity generation, 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 feasibility study for integration of the following technologies in the Rwanda Energy System:

   a. Utility Scale Solar PV (with storage).
   b. Hydro-pumped storage.
   c. Generic consumer-sized battery storage.
   d. Utility Scale Solar PV.

vi. Demand growth inducing policies need to be improved to stimulate electricity demand in line with development aspirations as set forth in NST1, Vision 2050.

vii. 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 peak and off-peak demand.

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

10.3. Way forward

NO	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/MINECOFIN)
		Demand forecasting to be updated regularly based on more realistic plans and assumptions aligned to the future planning cycle.
		Accelerate priority identified feasibility studies for: • Utility-scale Solar PV with storage • Hydro-pump storage • Grid-scale Battery Energy Storage Systems • Green Hydrogen

NO	CHALLENGE	RECOMMENDATION(S)
2.	Ascertaining the exact amount of lake methane that can be exploited for electricity production in an economical and sustainable way.	An updated and comprehensive resource study has been conducted to ascertain the existing resources in Rwanda. These resources include solar, hydro (including 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 to policy targets of 12% and above. Especially, to catch up form unrealized growth in the previous years, i.e., 2018-2022.
		Required infrastructure for industrial parks to be in place and the need to accelerate implementation of flagship projects of the Rwanda Vision 2050.
		Introduce more commercial and industrial demand and provide incentives for consumption in off-peak (Introduction of reduced tariffs for consumers during off-peak periods to promote load shifting).
4.	System Stability	Installed capacity of new power plants should not exceed a multiple of 10% of Rwanda grid capacity (peak demand) at the time of CoD. 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	There is a 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 reliability of the system.
		There is also a need to develop peaking power plants and/or storage embedded systems to absorb excess off-peak capacity and efficient load balancing.
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

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