AFRICAN CENTRE OF EXCELLENCE
IN ENERGY FOR SUSTAINABLE DEVELOPMENT (ACE-ESD)
COLLEGE OF SCIENCE AND TECHNOLOGY, UNIVERSITY OF RWANDA

The study on an optimum development of Green and Least Cost Generation Expansion Plan in Rwanda

By

AMAHIRWE Jean Claude

Ref. No: 220006332

A dissertation submitted to the African Centre of Excellence in Energy for Sustainable Development (ACE-ESD)

College of Science and Technology, University of Rwanda In Partial Fulfilment of the Requirement for the Degree of Master of Science in Electrical Power Systems.

Supervisor: Dr BIKORIMANA Jean Marie Vianney

4th December 2023

Kigali-Rwanda

DECLARATION

This is to certify that the thesis entitled "**an optimum development of green and least cost generation expansion plan in Rwanda**", submitted in partial fulfilment of the requirements for the degree of master of science in electrical Power systems, is a record of original work carried out and has never been submitted to this or any other institution to get any other degree or certificate. The assistance and help I received during this study have been acknowledged.

Name of student: AMAHIRWE Jean Claude Signature:

Date of submission: 08/12/2013

This thesis work has been submitted for examination with my approval as a university advisor.

Thesis supervisor: Dr BIKORIMANA Jean Marie Vianney Signature

ACKNOWLEDGMENT

First and foremost, I want to thank God for enabling me to complete this work. I also want to express my sincere gratitude and appreciation to everyone who has helped me to multiply my efforts in order to finish this thesis. I would like to take this opportunity to warmly acknowledge the ongoing support, supervision, timely advice, and inspirational guidance provided by my supervisor, Dr. BIKORIMANA Jean Marie Vianney, for the successful completion of this thesis. I also want to thank the manager of Energy Utility Corporation Limited (EUCL) for granting me access to the data I needed for this research. Finally, I want to thank all department staff who are related to my work for patiently providing all kinds of help for finishing this ambitious project.

Finally, I would like to thank college of science and technology under university of Rwanda in cooperation with world bank for financial assistance that enabled me to complete all the lessons and my thesis.

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LIST OF ABBREVIATIONS

A-Si: Amorphous silicon solar cell

CDM: Clean development mechanism

CdTe: Cadmium telluride solar cell

CER: Certified emission reduction

CONGEN: Configuration generation

C-SI: Crystalline solar panels

DP: Dynamic programming

DYNPRO: Dynamic programming optimization

EPC: Engineering procurement and construction

FIXSYS: Fixed system description

GCM: Generation cost model

GDP : Gross domestic product

GEP: Generation expansion planning

GLCGEP: Green least cost generation expansion plan

IAEA: International atomic energy agency

IEA: International energy agency

IEEE: Institute of electrical and electronics engineering

LCPDP: Least cost power development plan

LOADSY: Load system description

LRMC: Long run marginal cost

Mono-SI: Monocrystalline solar panels

Multi-SI: Multi-crystalline solar panels

REG: Rwanda energy group

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ABSTRACT

One of the sources of CO_2 that contributes to climate change is the power generation industry. Diesel is gradually running out because it is getting more and more expensive over time. Although electric vehicles were developed to solve this problem, there is a possibility that this will lead to a significant increase in electricity consumption in the near future. In mitigating these issues, the study developed a green least cost generation expansion plan (GLCGEP) as a substitute of the least-cost power development plan (LCPDP) for Rwanda that was developed by REG in 2020.

The study's objectives were to identify the best GLCGEP based on the green candidate plants, find the national peak demand estimate for 2038, and establish a comparative analysis between the GLCGEP and LCPDP.

The electricity generation cost optimization was used for selecting the green candidate plants. Quadratic regression trend mathematical model was formulated to predict the demand forecast. With data collection from EUCL, the existing and committed plants were identified.

The Generation analysis planning (GAP) tool was used to simulate the chosen green candidate plants, the demand projection, the committed and existing plants, and the best GLCGEP was determined.

In 2022 the national peak was 201.4 MW, by 2038 the peak was predicted to reach 750.1MW. The 42MW hydropower, 24MW peat, 30MW methane gas and 12 MW solar was determined as the optimal green candidate plants. The long run marginal cost for the electrical energy added on the system was 0.16$/kWh as the base price. The energy supply mix has risen from 1995.1 GWh in 2023 to 5006.2 GWh in 2038. The significant increase in energy will occur in 2038 with an increment of 404.6 GWh.

CHAPTER ONE. INTRODUCTION

1.1 Background of the study

Rwanda has considerable natural energy resources, including hydropower, solar, peat, thermal power, and methane gas. Today, Rwanda has the total installed capacity of 353.4MW including off grid capacity. It is from different power plants where hydropower contributes 31% of the total installed capacity, thermal sources contribute 16.6 %, solar sources contributes 3.4% , peat contributes 24.1% , 8.4% from methane gas and the remaining part is from import and shared power. This was accomplished by allowing private energy investors known as independent power producers (IPPs) to participate in raising the installed capacity of the country. The growth of the total installed power plants was shown by Rwanda Energy Group (REG) in figure1.

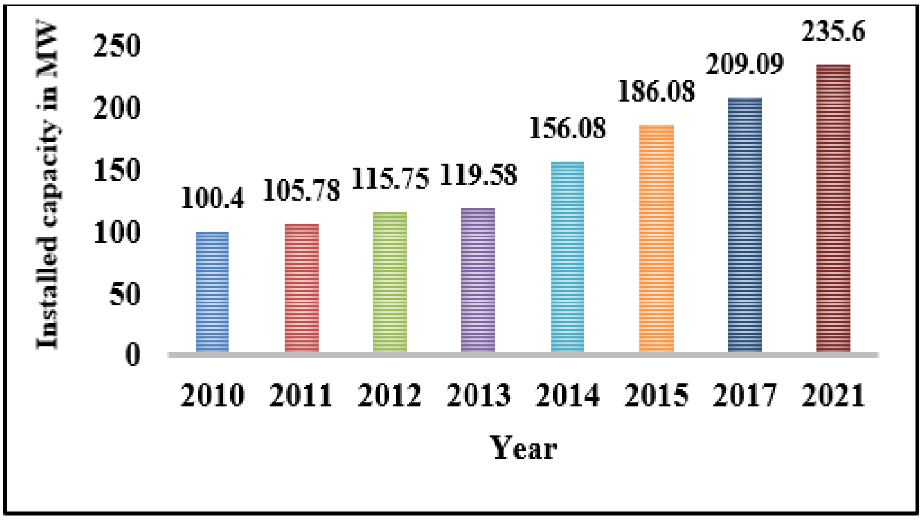

Figure 1: Evolution of power installed capacity in Rwanda from 2010 to 2021[1]

Electrical power development and reliability is a critical input for economic, social and political development of a country. Therefore, it is crucial that a nation have a sufficient and consistent supply of power to suit its needs, mostly depending on the available resources.

The creation of a least-cost generating development plan offers a practical roadmap for how power demand can be fulfilled in the medium and long terms at the lowest possible cost. Rwanda generating master plan's primary goal is to meet the nation's anticipated rising demand for power while preserving a respectable operating reserve margin.

Currently, Rwanda has limited resources available for generating electricity, particularly during the dry season when many hydro power facilities experience water shortage issues. In that case, diesel generating power stations are employed to meet the peak demand [1], however this generation is expensive.

The increase of Rwanda's generation is based on both government-funded projects and contracts with private companies. The need for government direct investment can be greatly reduced by accelerating the expansion of privately funded generation. This process of meeting the electrical energy demand should be done in organized and planned manner.

1.2. Statement of the problem

Currently the energy mix in Rwanda shows that there is a significant contribution of thermal energy sources (diesel, peat and methane gas) which presents around 50% of the total installed capacity. The studies show that thermal power plants emit more green house gas especially carbon dioxide. That carbon-intensive capacity increases the CO2 emissions in contradiction to the national and global climate change mitigation strategies.

The cost of diesel is highly increasing with time which means the diesel is exhausting little by little. To overcome this problem the electric vehicles was introduced however, It might increase significantly the electricity consumption in near future.

In view of this, a least cost generation energy planning (GEP) based on CO2 emission reduction strategy is an urgent concern for energy planners.

1.3. Objectives

1.3.1. Main objective

Making a green and least-cost generation expansion plan (GLCGEP) is the primary goal of the study, which aims to enhance REG's least-cost power development plan done in 2022.

1.3.2. Specific objectives

The following are the specific goals:

- To identify Rwanda's green and least cost candidate power plants for generation expansion planning.
- To determine the anticipated national peak demand in 2038.
- To calculate Rwanda's ideal GLCGEP based on green candidate power plants.
- To compare the techno-economic features of the least cost power development plan completed by REG in 2022 with the GLCGEP.

1.4. Research questions

1.4.1 Main research question

Is it possible to replace the 2022–2040 LCPDP with the GLCGEP case study? was the study's primary research question.

1.4.2 Specific research questions

The following were the specific research questions:

1. Which green candidate power plants are Rwanda's best options for generation expansion?
2. Considering the green candidate power plants, which GLCGEP is the optimal for Rwanda?

1.5. Scope of the research

The scope of the study was limited to 15 years planning from 2023 to 2038. GAP was used for simulation. The Selection for green candidate generation plants for GLCGEP will be limited to hydropower, solar, peat, methane gas and geothermal electrical energy sources. Other sources like wind and biomass are found not applicable so far in Rwanda.

1.6. Significance of the study

Growing economies are directly linked to higher energy demand, as indicated by GDP (gross domestic product). This relationship requires accurate annual capacity additions in addition to other predetermined conditions in order to meet the increasing demand at the lowest feasible cost. [2]. Consequently, GEP is an essential component of strategic development for every nation.

As the primary source of CO2 emissions are from fossil-fuel power plants, the worldwide generation industry has been under the focus in the 21st century due to worries about climate change. There is a lot of pressure on the global generation sector to reduce CO2 emissions. [3] Currently, the best environmental protection strategy to slow down the rising rates of emissions is to expand green-based generation. [4]

In Rwanda, as the population grows, the electrical energy consumption also increases with time. For instance the study made for 2015-2050 showed that the population increased from 12M to 33M while the energy consumption had grown from 600 to 1700GWh [26]

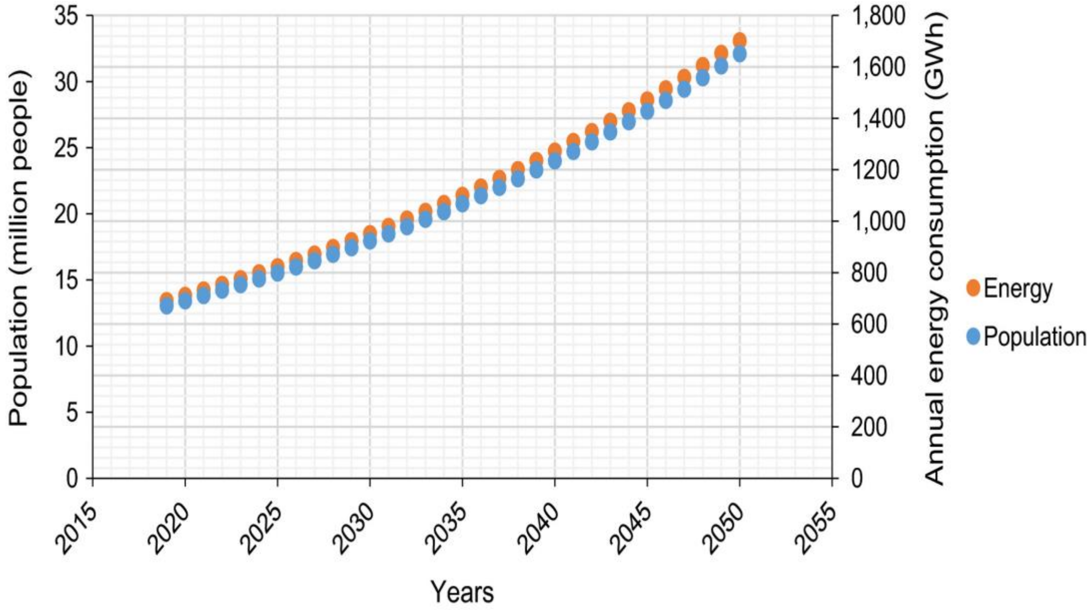

Figure 2: Population growth with energy consumption [26]

The current energy mix shows that around 60% of the total electrical power generated is from non renewable energy sources. These sources include peat, thermal(diesel) and methane gas. The study shows that peat, diesel and methane gas can produce the following CO2 emissions per KWh, 900,700 and 350 gCO2 respectively. [5]

Due to the unpredictability of estimates, Israel Electric Company undertook an other study that took into account various yearly growth rates of 8% (low growth), 10% (base scenario), and 12% (high growth). Forecasts for electricity consumption were then created using the hourly load curves that were in place for the years 2015–2016 and taking into account recent historical trends. Considering the base scenario (10% growth rate), the study shows that the energy consumption growth is estimated to reach 6000GWh in 2040 [1]. Therefore social economic growth implies the growth of electrical energy consumption. As the need in electrical energy increases also the electrical power should be supplied accordingly to meet the demand. And this should be done with a careful study that minimise the electrical power generation cost and green house gas emissions.

This is the justification for establishing the GLCGEP for Rwanda in order to encourage the production of clean energy and sustainable development.

1.7. Thesis outline

The outline of this project consists of five chapters.

- The first chapter is Introduction, which provides a brief overview of the study's background and motivation, problem statement, objectives, research questions, scope, and project outline.
- The second chapter is the theoretical background and literature review, which includes related work done by other researchers on this topic, as well as theoretical concepts and fundamental definitions used in this research project.
- The third chapter describes the research methodology and tools used in the project's implementation as well as modelling and simulation of the system utilized to solve the stated problem.
- The fourth chapter presents a discussion and results analysis of the project research findings in relation to the project objectives.
- The fifth chapter discusses the research findings' conclusion and recommendations.

CHAPTER TWO: LITERATURE REVIEW ON GREEN AND LEAST COST GENERATION

2.1 Introduction

An overview of least cost generation, green generation, and generation expansion planning will be addressed in this chapter. It also goes over the methods for load forecasting using the case study as a guide. This chapter also covers an overview of relevant literature on green-based GEP, carbon emission trading, green jobs for the low-carbon world, and technical issues related to renewable energy power generation.

2.2 Green generation

Green generation is the production of electrical power from renewable resources. Six primary renewable energy technologies are currently in use worldwide: solar photovoltaic (SPV), wind, solar thermal, geothermal, biomass, and hydroelectric power. There are several configurations that correspond to permutations, combinations, and hybrid arrangements of the constituent technologies under each of these major categories.

2.2.1 Solar photovoltaic power systems

Materials based on semiconductors are used in solar PV systems to directly convert solar energy into electrical power. Since its development in the 1950s, SPV technology has steadily decreased in cost and gained popularity for a variety of uses, most notably meeting the need for remote power for lighting, pumps, and telecommunications. Numerous appealing characteristics of SPV systems include their modularity, lack of fuel requirements, noise reduction, zero direct emissions, and grid connection independence.

Three main applications are used to categorize SPV systems: stand-alone solar devices, such as water pumps and home power systems; small solar power plants intended to supply electricity to villages; and grid-connected solar photovoltaic power plants.

The technology used in solar photovoltaic power systems is not truly emission free. According to the study, the primary indirect emissions associated with this technology come from the production of its components. According to the results, the emissions intensities for SPV technology range from 1 g CO_2-eq/kWh at low to 218 g CO_2-eq/kWh at high [6].

The study done by Rupert Lloyd Hough in 2022 shows that cadmium telluride solar cell emit much CO_2 than other type of solar PV. The figure 2 shows the quantity of CO_2 emission with respect to the type of solar PV.

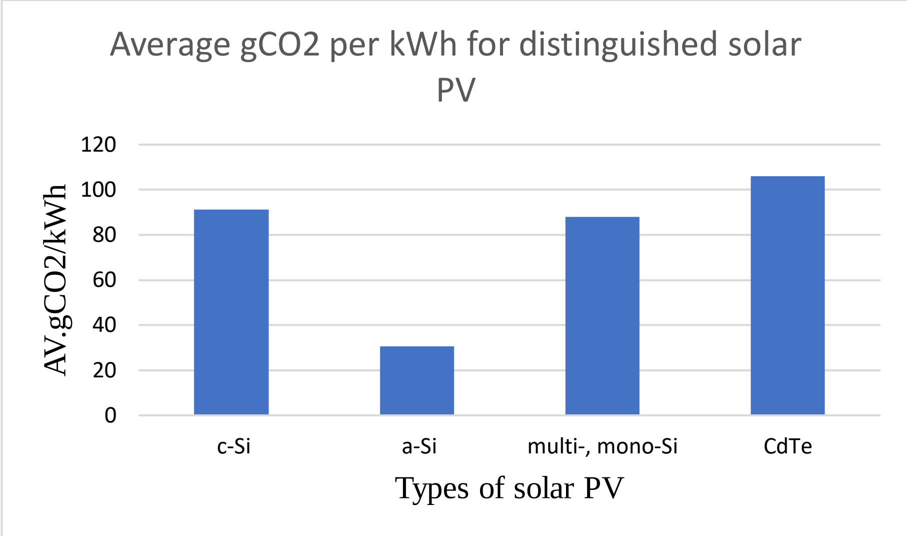

Figure 2: Solar PV average gCO2 emission per kWh.[7]

2.2.2 Wind power systems

The process of utilizing the wind to produce electricity or mechanical power is known as wind power. The kinetic energy of the wind is transformed into mechanical power by wind turbines. There are specific uses for this mechanical power. A generator can also turn it into electricity. There are two categories for wind turbines: small (up to 100 kW) and large. Large wind turbines are only used as grid-connected power sources; small wind turbines are used for off-grid, mini-grid, and grid-connected applications. The rotor blades, generator, power regulation, aerodynamic (Yaw) mechanisms, and tower are the parts of a wind turbine [8].

The technology used in wind power systems is not truly emission free. According to the study, the primary indirect emissions associated with this technology come from the production of its components.

There are far fewer life cycle greenhouse gas emission studies on offshore wind than onshore wind, according to a recent review. The average lifecycle greenhouse gas emissions across these studies were found to be 13.075.2 gCO2eq/kWh, with a range of 5.3–24 gCO2eq/kWh. Estimates of greenhouse gas emissions from offshore wind life cycles are typically lower than those from onshore wind. Due to the fact that offshore installations are frequently substantially larger than their onshore counterparts, economies of scale help to partially explain this.

Since onshore activities often require the destruction of forest or peat land ecosystems in addition to raw material extraction, both of which result in large GHG emissions, it is assumed that onshore activities will have higher GHG emissions during the construction phase [9].

2.2.3 Solar-thermal electric power systems

Solar energy must be gathered in concentrated densities large enough to run a heat engine in order to produce power from solar energy through thermal-electric power conversion. There have been several attempts at concentrating solar energy, such as central receivers, parabolic trough collectors, and parabolic dish collectors. The only configuration that has advanced to a commercial level is the parabolic trough.

Because greenhouse gases are released during the provision of services and the manufacturing of materials required for the construction and operation of solar power plants, solar-thermal electricity generation is a contributing factor to climate change. Plants that run solely on solar energy and use parabolic troughs, parabolic dishes, or central receivers show about 90 g CO_2-eq/kWh. To boost the plant's capacity factor, this number varies depending on the size of the plant and whether a heat storage system or a backup powered by fossil fuels is used [10]. The figure 3 shows the principle of the parabolic trough power plant with thermal storage.

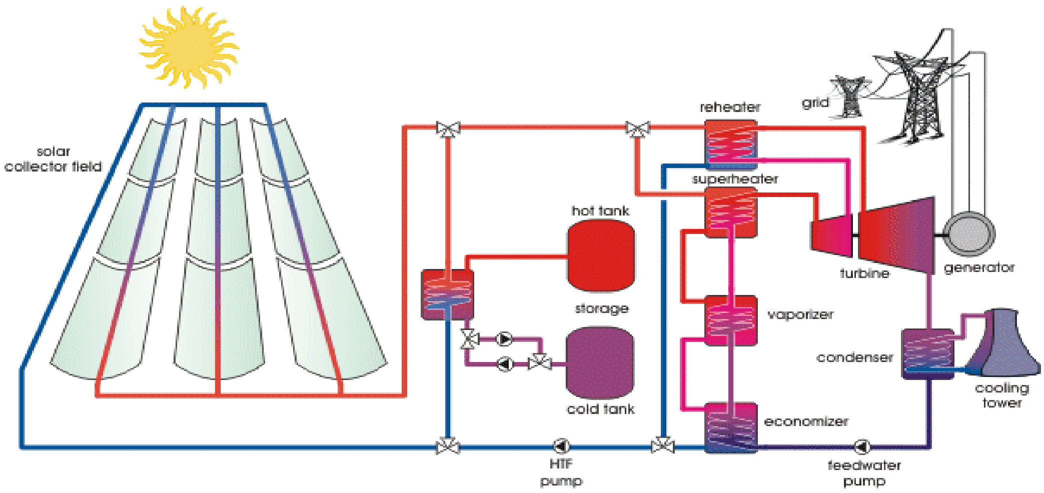

Figure 3: Schematic of a concentrated solar thermal trough power plant [10]

In above shown solar thermal, a proven form of storage system uses two tanks to function. Melted salt is used as the storage medium for high-temperature heat storage. Melted salt is pumped from the cold to the hot tank, where it is heated by the solar collector field's excess heat. Melted salt is pumped back from the hot to the cold tank, heating the heat transfer fluid, in case the solar collector field is unable to generate sufficient heat to power the turbine.

A single-axis mechanical tracking system that is oriented east to west is used by a parabolic trough concentrator to track the sun. A receiver situated along its focal line receives the solar insolation that is focused by the trough. Enough concentrators are placed in order to produce the necessary quantity of thermal energy, which is then transferred to a central power block via a heat transfer fluid, where the heat produces steam. The steam turbine, generator, and their auxiliaries make up the power block. With thermal storage included, a solar-thermal electric power plant can have a higher capacity factor at a higher cost [11].

2.2.4 Geothermal electric power systems

One of the main drawbacks of renewable technologies, particularly solar and wind power, is the sporadic nature of the resources they require. This results in a higher economic life cycle cost per kWh, variable power output, and a comparatively low capacity factor. Utilizing geothermal resources is beneficial in this situation. The limitations of intermittent renewable technologies are overcome by geothermal technology, which is distinguished by its dependability, high capacity factor, and continuous output power [12]. Geothermal electric power system is shown in figure 4.

Hydrothermal resources that occur naturally are the main types of geothermal resources being developed for commercial use. Steam and hot water are found in relatively shallow basins, which are known as hydrothermal reservoirs. Because hydrothermal reservoirs are naturally porous, liquids can escape from wells that are drilled into them. The availability of the resource and the requirement for prospecting and exploitation capability for geothermal resources limit the commercial use of geothermal systems in underdeveloped economies.

Three sizes of geothermal power systems are evaluated: a smaller size appropriate for mini-grid applications, and a bigger one appropriate for grid uses. With capacity factors similar to those of conventional generation, large geothermal facilities function as base-loaded generators. Due to restrictions in local demand, smaller plants intended for mini-grid applications will have capacity factors between 30 and 70 percent. Although, geothermal power facilities do not operate without emissions. The emissions of hydrogen sulfide (H_2S) from this technology are limited to 0.015 kilos per megawatt-hour. The study shows that the estimate of life cycle GHG emissions (in g CO2eq/kWh) vary between 11.3 and 47.0 depending on the type of geothermal power plant.

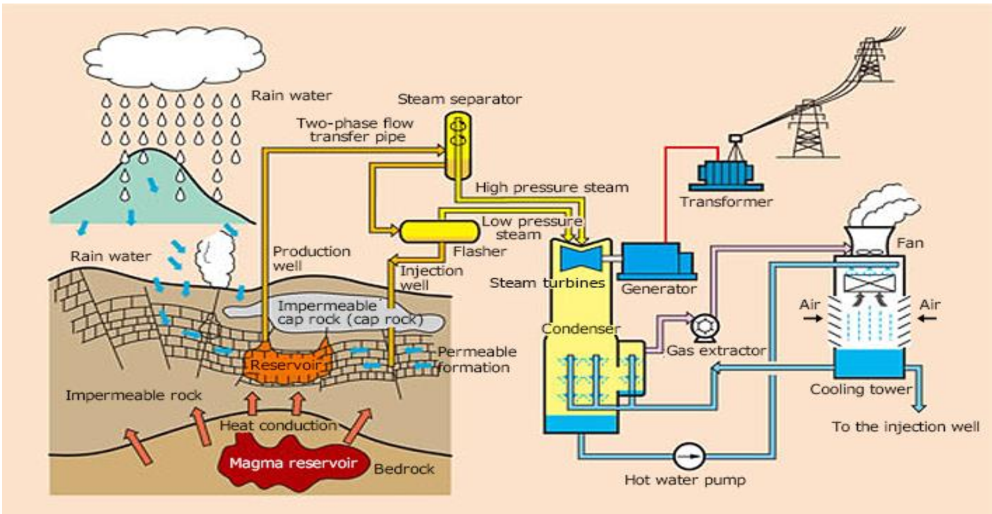

Figure 4:Geothermal power plant.[12]

In the process of producing geothermal power, a magma reservoir heats groundwater to a high temperature and pressure, which powers a turbine to produce energy.

2.2.5 Hydroelectric power plant

It is made up of a number of structures and electromechanical devices that convert the potential energy of water into electrical energy and can run continuously. The available electrical energy is proportional to the flow rate and the drop in elevation.

It is made by six main parts namely: a part which contains the river water, forming a reservoir behind it and thus creating a water drop that is used to produce energy (dam), a part which houses the hydraulic and electrical equipment and the service area with control and testing rooms (Powerhouse), a part that drives the alternator through the shaft(turbine), transformers and spillways. The research shows that the hydroelectric power plant presents two types of emissions: first, direct and indirect emissions associated with the construction of the plants;

second, emissions from decaying biomass from land flooded by hydro reservoirs. In terms of GHG emissions, hydropower is a good alternative to fossil fuelled power generation. For hydropower plants in cold climate the emission factor is 15 g CO_2 equivalent/kWh, which is 30–60 times less than the factors of usual fossil fuel generation [13]. The study done by Rupert Lloyd Hough in 2022 shows that the hydropower plant with dam emit much CO2 than other type of hydropower plant. The figure 5 shows the quantity of CO2 emission with respect to the type of hydropower plant.

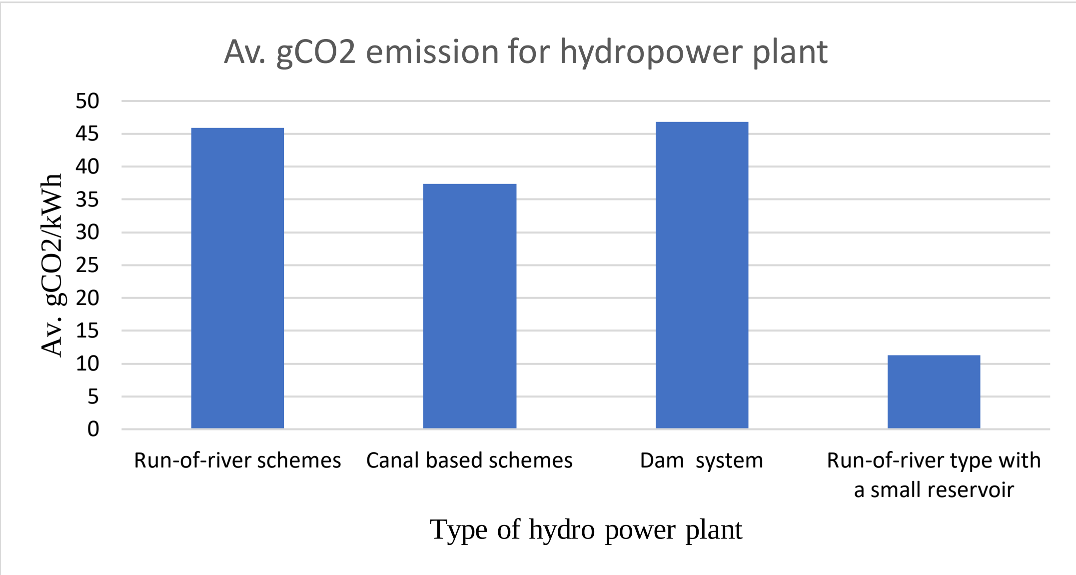

Figure 5:CO2 emission per types of hydropower plant.[13]

2.3 Least cost generation

2.3.1 Hydroelectric power cost of generation

Hydropower requires a lot of planning, design, and civil engineering work, making it a capital-intensive technology with lengthy lead times for development and construction. Hydropower investment costs vary greatly based on the location, design options, and cost of labour and materials in the area. Compared to certain other renewable technologies, the cost of labour and materials contributes more to overall costs in hydropower due to the significant civil works that must be completed. The variation in the electro-mechanical costs is considerably smaller

Large-scale hydropower projects usually have total installed costs between USD 1 000/kW and USD 3 500/kW. It is not unusual, though, to come across projects that cost more than this range. For example, it might be less expensive to add hydropower to an existing dam that was constructed for uses other than flood control or water supply. However, projects at isolated locations that lack sufficient local infrastructure and are separated from current transmission networks may end up costing much more than USD 3,500 per kW.

Increasing capacity at already-existing hydropower schemes or obtaining energy from existing dams without hydropower facilities are usually associated with the lowest investment costs. Small projects are anticipated to have higher average costs and investment costs in slightly higher range bands. This is especially the case for plants under one MW in capacity, where the specific (per kW) electromechanical costs can be very high and account for the majority of the total installed costs. Small hydropower plant projects typically have lower investment costs per kW the higher the plant's installed capacity and head. Regardless of head size, there is a strong correlation between installed capacity and specific investment costs [14].

2.3.2 Geothermal electric power cost of generation

Although they require a large amount of capital, geothermal power plants have extremely low and predictable operating costs. The cost of development has gone up over time along with the price of commodities, drilling, engineering, procurement, and construction. The following items make up a geothermal power plant's total installed costs:

• The price of exploration and resource evaluation

• Drilling wells for re-injection and production. Since a production's success rate typically ranges from 60% to 90%, this calls for a backup plan.

• Surface installations, the geothermal fluid collection and disposal system, and field infrastructure

• The cost of the power plant and its related expenses; and • The costs of project development and grid connection. [15]

Given the quality of the geothermal field and its geographic distribution, the features of the field will have a major impact on the type of power plant that can be used (flash or binary), on well productivity and energy delivery,34 and on the capacity for which it is economically viable to provide steam.

The total installed costs of geothermal power plants increased by 60% to 70% between 2000 and 2009. In addition to the overall increases in civil engineering and EPC costs during that time, project development costs increased due to the drilling industry's above-average rate of cost inflation, which was brought on by rising oil and gas prices. Conventional condensing "flash" geothermal power generation projects now cost between USD 1 900 and USD 3 800/kW when fully installed in 2009.

When capacity is added to a geothermal reservoir that is already well characterized and where existing infrastructure can be used, project costs can be as low as USD 1 500/kW, but these are exceptional cases [15].

2.3.3 Solar photovoltaic power cost of generation

Historically, a key factor in increased competitiveness has been the declining cost of solar PV modules, and in 2020, this trend persisted. Depending on the type, prices of crystalline silicon modules sold in Europe decreased by 89% to 95% between December 2009 and December 2020. During that time, the weighted average cost reduction was approximately 93%. The figure 6 shows how annual PV production increased from a few kW in 1989 to approximately 35000 MW in 2013, and how the cost of a PV module decreased from approximately 16 USD in 1991 to 1 USD in 2013.

Typical modules sold for USD 0.27 per watt (W) in December 2020. However, prices vary greatly based on the module technology taken into account. For high efficiency, costs ranged from USD 0.19/W to USD 0.40/W. This price range represents an approximate 9%–11% decrease from December 2019 [3].

According to the study, utility-scale projects that were put into service in 2020 had a global capacity weighted average total installed cost of USD 883/kW, which was 13% less than in 2019 and 81% less than in 2010. The project's installation costs in 2020 ranged from USD 2 346/kW to USD 572/kW. This cost range's long-term downward trend suggests that cost structure improvements will continue in a growing number of markets.

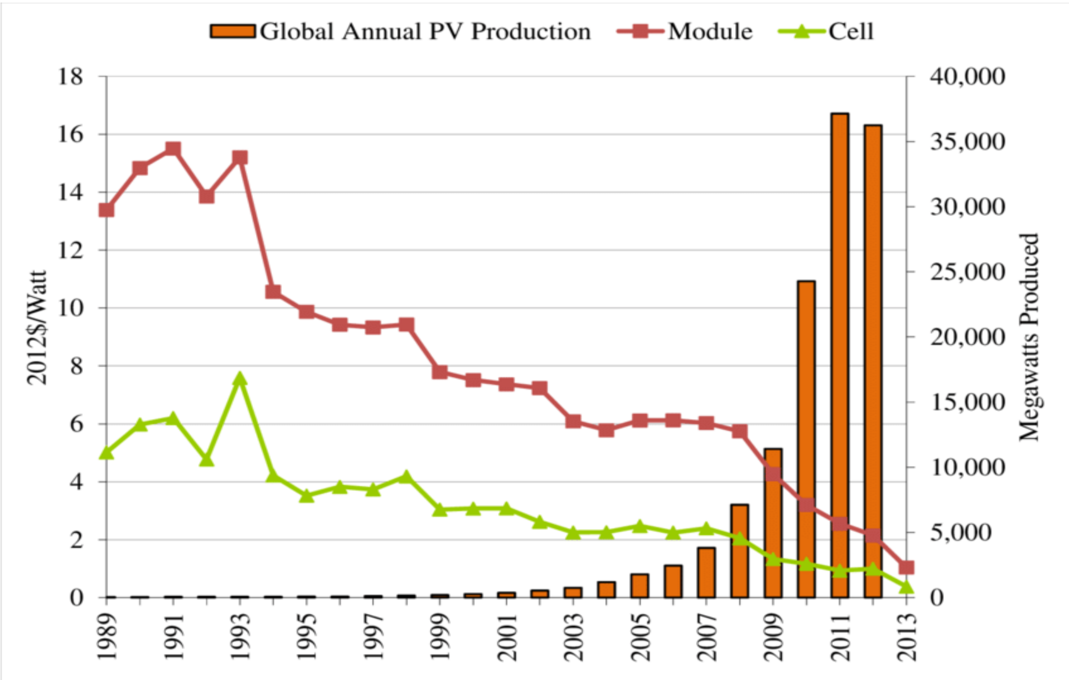

Figure 6: Solar PV Cell and Module Prices (2012$/Watt), 1989-2013. [15]

Reductions in the total installed cost of solar PV are dependent on a number of factors. The optimization of manufacturing processes, decreased labour costs, and improved module efficiency are the main factors influencing lower module costs. As a result, PV systems are now achieving competitive cost structures and declining global weighted average total installed costs in a greater number of markets. All of the major historical markets in China, India, Japan, the Republic of Korea, the United States, and German saw notable reductions in total installed costs in 2020 [15].

2.3.4 Wind power systems cost generation

Wind is a capital-intensive renewable energy technology, just like other ones that do not require fuel. Investment costs, fixed and variable operation and maintenance costs, capacity factor, economic lifetime, and cost of capital are the main factors influencing wind power economics.

The initial capital cost of the wind turbines, which can account for 84% of the total installed cost, is what drives up the cost of a wind power project. Though there is no fuel price risk once the wind farm is built, the high upfront costs of wind power can hinder its uptake, much like other renewable technologies [15].

A wind power project's capital expenses can be divided into the following main categories:

The costs of the turbine, which include the blades, tower, and transformer; the civil works, which include the building of the foundations for the towers and the preparation of the site for construction; the costs of the grid connection, which can include sub-stations and transformers as well as the connection to the local distribution or transmission network; and other capital expenses. The last one could be related to building construction, control systems, project consulting fees, etc.

The tower, the gearbox, and the rotor blades are the turbine's three most expensive parts. These three components collectively make up between 50% and 60% of the turbine's cost. About 13% of the turbine's expenses are related to the generator, transformer, and power converter. The remaining "other" costs are made up of various tower-related expenses like the rotor hub, cabling, and rotor shaft.

For onshore wind farms in developed nations, the installed cost of wind power projects currently ranges from USD 1 700/kW to USD 2 150/kW. However, installed costs are only USD 1 300/kW in China, where about half of the recent additions to wind power have been made.

While worldwide time series data are not easily accessible, data specific to the United States indicates a notable decrease in installed costs from the early 1980s to 2001. In the United States, the average installed cost of a project was approximately USD 1 300/kW between 2001 and 2004. Nevertheless, the cost of installing wind power rose steadily after 2004 and reached about USD 2000/kW.

There are a number of factors contributing to these price increases, including:

- The sharply rising cost of commodities overall and the price of steel and copper in particular.
- The shift to offshore developments may be raising average installed costs in Europe. This is being accelerated by the shift from a superficial water projects driven by Denmark to deeper water projects in the United Kingdom and Germany.

In more complex systems the demand expanded so quickly. There are shortages in some components such as: wind turbines, gear boxes, blades, bearings, and towers and challenges in the supply chain and human capacity were experienced. This resulted in increased costs. Prices were also driven up by the growing complexity of component integration, grid interaction, and turbine design [15].

2.4 Green and least cost based generation expansion planning

Renewable energy sources are and always will be the most affordable. In actuality, the costs of renewable energy are currently advantageous and competitive when compared to fossil fuel alternatives, which are also highly polluting. These days, everyone is trying to reduce their greenhouse gas emissions in order to slow down climate change. This section covers the shift to green least-cost generation expansion, carbon emission trading, opportunities resulting from a low-carbon world, and technical issues related to the generation of power from renewable energy sources.

2.4.1 Planning for expansion through the shift to green least-cost generation

The classic definition of the GEP problem is the process of determining which, where, and when new generation plants should be built over an extended planning period to meet the anticipated energy demand [16]

When it came to long-term generation investment criteria, the usual ones were to minimize capital and operating costs and maximize system reliability within the constraints of available technology, capacity, and operation [8]**.** However, In the twenty-first century, the generation sector's growing concerns about reducing the effects of climate change have been added as an environmental factor to the issue of minimizing environmental emissions [17].

Currently, GENCOs view the integration of green power as a critical component in achieving the required reductions in carbon emissions in the least-expensive GEP [4].

The research on green-based GEP shows that green generation investments can significantly reduce carbon emissions and promote sustainable development. The authors highlight the significant investment potential in green-based generation, particularly in developing nations [17].

2.4.2 Carbon emission trading

There are now business opportunities as a result of the global effort to reduce carbon emissions to slow down climate change. The Kyoto Protocol's (KP) adaptable international market-based mechanisms for energy sufficiency and emission reduction are starting to be recognized by a large number of nations. The most pertinent mechanism for developing nations that can voluntarily improve environmental sustainability but do not have to make binding commitments to reduce emissions is the clean development mechanism, or CDM [2].

Under the CDM, a developed nation can establish carbon emission diminution initiatives in a developing nation where the establishment costs are lower. The projects' reduced emissions produce certified emission reductions (CERs), which are carbon credits that are exchanged on the carbon market. To assist the developed countries in meeting their KP emission commitments, They purchase the carbon credits from the developing nations. In doing so, CDM promotes the growth of renewable energy projects, which at the moment make up 68% of all globally registered CDM projects [5].

Despite the fact that CDM encourages green investments, the projects have high initial expenses, prolonged payback periods, and uncertainty. Investing in the growth of green-based generation carries a great deal of risk. Nonetheless, a number of energy-related incentive programs, including feed-in-tariffs (FiT) and power purchase agreements (PPA), have been successfully implemented in numerous nations worldwide to reduce risks and encourage the investment in green electrical energy production [2].

There are three primary issues with CDM implementation that have been noted as limiting its global adoption. Firstly, it takes a minimum of 1.5 to 2 years for CDM project developers to validate, register, and issue CERs; this is a significant time commitment. Secondly, the pricing of the profit-regulated carbon market is extremely unstable and dependent on supply and demand. For example, a CER was worth US$32.6 in 2005, but over time, its value dropped to US$ 3.04 by 2014, preventing many investors. Last but not least, false projects have been approved at the expense of taxpayers due to fraud and forgery of CDM projects [5].

2.4.3 Green employment for a low-carbon future

Green generation investment patterns that support green jobs have increased as a result of global efforts to create a low-carbon economy. In the green generation industry, a large number of people work in the manufacturing of power plant machinery and equipment, project management, purchasing and logistics, construction, operation and maintenance, finance, legal services, and consulting. Also, the owners of green projects are subject to certain taxes [18].

The US, Germany, China, Japan, and Brazil are the countries with the highest concentrations of green power technology production, investment, and research and development (R&D). These countries produce the majority of the world's green jobs. On the other hand, a lot of developing nation host countries benefit from having more locally focused construction, operation, and maintenance jobs. [2]

Approximately 2.5 million people are employed worldwide in the green generation sector. A sizable portion roughly 52% are thought to be employed in Brazil, the US, Germany, and China. Other sectors include solar PV at 7.4%, wind power at 13%, and solar thermal at 26%. Other developing countries are starting to benefit from this era of green growth for sustainable development, even though the majority of the increase in green jobs is occurring in industrialized and rapidly developing nations [2].

2.4.4 Technical concerns with renewable energy power generation

It is projected that the integration of renewable energy (RE), a key component of green growth, will increase dramatically, particularly in developing nations. GENCOs and power system operators, however, encounter three difficulties when incorporating solar and wind energy into their systems. The sources are highly variable and site-specific, which makes the reliability of the system uncertain. Unexpected disruptions to the system due to load fluctuations, grid failures, and power outages occasionally occur.

Worldwide, the number of power generation sources is rising due to solar and wind energy. However, there are certain technological difficulties in incorporating wind and solar energy into the electrical grid. For instance, variations in wind speed affect the windmill plates' rotational speed, which alters the voltage, frequency, and power. Rising renewable energy penetration calls for balancing electrical power [6].

2.5 Green and least cost planning based on case study load forecasting

In Rwanda, the 2016-2040 least cost power development plan projected a hydropower, peat and methane gas to dominate power generation [1]. In this plan however, a big part of generation is supported by hydro power. During dry season the shortage of water flow becomes a challenge to meet the electrical energy demand. In this plan also thermal(diesel) is included to act as back up during the peak demand especially during dry season. The following part discusses the types, importance and methods of load forecasting.

2.5.1 Brief description of load forecasting

The process of looking at power system planning begins with forecasting. Forecasting is a two-sided process. Energy forecasting is the second aspect, and demand forecasting is the first. The capacity of an element within the power system is ascertained through demand forecasting. The type of generators required is another aspect of forecasting that comes in second. The advantages of load forecasting are listed below [19]. The ability to accurately and comprehensively plan for the future is facilitated by forecasting for power system operators.

- The financial risk to the system operators is decreased by forecasting.
- By preventing working under or over a generation, forecasting maximizes the generation of power.
- The kind of generating technology to be employed for the expansion of the power system can be selected using forecasting.

2.5.2 Types of load forecasting

To be aware of the load requirements ahead of time, load forecasting is necessary. The ability to forecast load is one of the most important components of an effective power system. Load forecasting is essential for operational and planning decision-making. Based on lead time or time horizon, there are three primary categories for load forecasting.

1. Short term load forecasting
2. Mid-term load forecasting
3. Long term load forecasting

The models and techniques used, as well as the available and chosen input data, are all impacted by variations in time horizon. In order to obtain the most accurate forecast, the decision maker must take into account not only selecting the best model type but also identifying the crucial outside variables [20].

2.5.2.1 Short term load forecasting

Short-term load forecasting, or STLF, is a crucial tool for managing daily power system operations like hydrothermal coordination, energy transaction scheduling, load flow estimation, and overload prevention decision-making. It typically forecasts the load up to one week in advance. Three primary categories of inputs are typically used for STLF. These include weather variables (temperature, humidity, wind, and cloud cover), seasonal input variables (variations in load brought on by air conditioners and heaters), and historical load data (hourly loads for the preceding hour, day, and week).

The estimated load for each hour of the day, the daily or weekly energy generation, and the daily peak load will be the output of STLF.

2.5.2.2 Mid-term load forecasting

Mid-term load forecasting (MTLF) is another kind of load forecasting. Its time horizon is longer, ranging from a week to a year. The scheduling of minor infrastructure modifications, fuel supply, and maintenance are all done using MTLF. A company can estimate the load demand over a longer time horizon with MTLF, which can be useful in negotiations with other businesses. MTLF is influenced by economic and demographic factors. A typical MTLF output is the daily average load and peak load [19]. MLTF is closely linked to STLF. It is necessary to integrate longer-term decision levels into short-term decision levels. This coordination between various decision levels is especially crucial to ensure that specific operation objectives that emerge in the medium-term are explicitly considered in the short-term [21]. Furthermore, in order for generation companies to become more profitable, coordination across decision levels has grown in importance.

2.5.2.3 Long-term load forecasting

The last type of load forecasting is long-term load forecasting (LTLF). The LTLF is valid for 20 years. Planning is required for projects like building new power plants, expanding the transmission system's capacity, and generally organizing the electric utility's growth. Indicators related to economic and demographic development also affect LTLF. LTLF takes into consideration a number of factors, including past peak load, population growth, and weather data such as temperature, humidity, and wind speed. The annual energy demand and annual peak load demand for the upcoming years are the results of this forecasting [22].

2.5.3 The importance of long term load forecasting

For electric utilities and planners, load forecasting over an extended period of time is crucial for planning grid expansion, future investment, and revenue analysis for long-term decision making. Furthermore, it is essential to a nation's social and economic development.

A broader range of future generating possibilities can be predicted in this globalizing environment when the demand for electricity is growing more quickly. LTLF usually provides a monthly or annual time-step for one to ten years in the future, assisting with inter-tie tariff setting and long-term grid investment return issues. This study is crucial because it offers customers an accurate prediction model, allowing them to share common information. Accurate forecasting is crucial because it ensures energy supply and maximizes the use of generated capacity already in place. In accordance with customer demand, the utility company can supply efficient electricity and set up an organization to distribute electricity evenly among its own clients.

The following are some implications of long-term load forecasting:

1. Gives the utility provider a clear picture of future consumption or load demand, enabling them to plan effectively.

2. Reduce the risks that the utility company faces. The business can better plan and make financially sound decisions about future generation and transmission investments by having a clear understanding of the long-term load in the future.

3. Aids in future planning with regard to the type, size, and location of the generating plant. If the utilities find areas or locations where demand is high or increasing, they will probably produce power close to the load. As a result, the transmission and distribution infrastructures' overall size and associated losses are decreased.[22]

2.5.4 Long-term load forecasting methods

There are several methods for long-term load forecasting, which can be divided into three primary groups: artificial neural network methods, time series model (ARIMA), and classical regression methods.

2.5.4.1 Classical regression approaches

This study employs load forecasting using classical regression approaches. One of the most popular statistical methods for load forecasting is regression. When performing the modeling, the relationship between load consumption and other variables, such as time, is taken into account.[31] Quadratic trend regression can be used for forecasting classical regression.

2.5.4.2 Quadratic trend regression

This regression model is a hybrid one that combines regression analysis with time series and time trend data. The peak load forecast values for the nation are shown to have a non-linear relationship by the model. This approach was selected for use because it offers a higher degree of accuracy over a planning horizon of no more than 20 years [23]. Quadratic trend regression model is given by the equation 2.1 where (y) and (x) represent the peak load and years respectively.

$$y = a_0 + a_1 x + a_2 x^2 \quad 2.1$$

While the constants a_0, a_1 and a_2 can be solved from the equations 2.2, 2.3 and 2.4

$$\sum_{i=1}^{n} yi = a_0 n + a_1 \sum_{i=1}^{n} xi + a_2 \sum_{i=1}^{n} x_i^2 \quad 2.2$$

$$\sum_{i=1}^{n} xiyi = a_0 \sum_{i=1}^{n} xi + a_1 \sum_{i=1}^{n} x_i^2 + a_2 \sum_{i=1}^{n} x_i^3 \quad 2.3$$

$$\sum_{i=1}^{n} x_i^2 yi = a_0 \sum_{i=1}^{n} x_i^2 + a_1 \sum_{i=1}^{n} x_i^3 + a_2 \sum_{i=1}^{n} x_i^4 \quad 2.4$$

CHAPTER THREE: METHODOLOGY

3.1. Introduction

In this study several methods was used to achieve the main objective. The used technics include; collecting written information related to the topic from different sources, collecting all the data needed, making the model with generation cost model (GCM) and simulation with generation analysis planning (GAP). The primary goal to achieve with this study is to create a least-cost, environmentally friendly expansion plan that could potentially replace REG's 2020 LCPDP.

3.2. An overview of the planning process for generation expansion

The study's primary goal was to increase Rwanda's portfolio of economically feasible green power projects. The study employed those plants to create an ideal GLCGEP after first identifying the green candidate plants in order to accomplish this goal.

The primary instrument for GEP in this study will be the available generation analysis planning. This tool is divided into several modules. The first three modules handle basic demand forecast, committed and existing generation plant, and candidate plant input data. These are the variable system (VARSYS), fixed system (FIXSYS), and load system (LOADSY), in that order. Each of the three modules runs separately from the others. After examining the first three modules, the following four will be run: dynamic programming (DYNPRO), configuration generator (CONGEN), re-merge and simulate (REMERSIM), and merge and simulate (MERSIM). The study report will be provided by the REPROBAT module lastly after optimization. Figure 7 shows the generation expansion plan methodology for the study. [2]

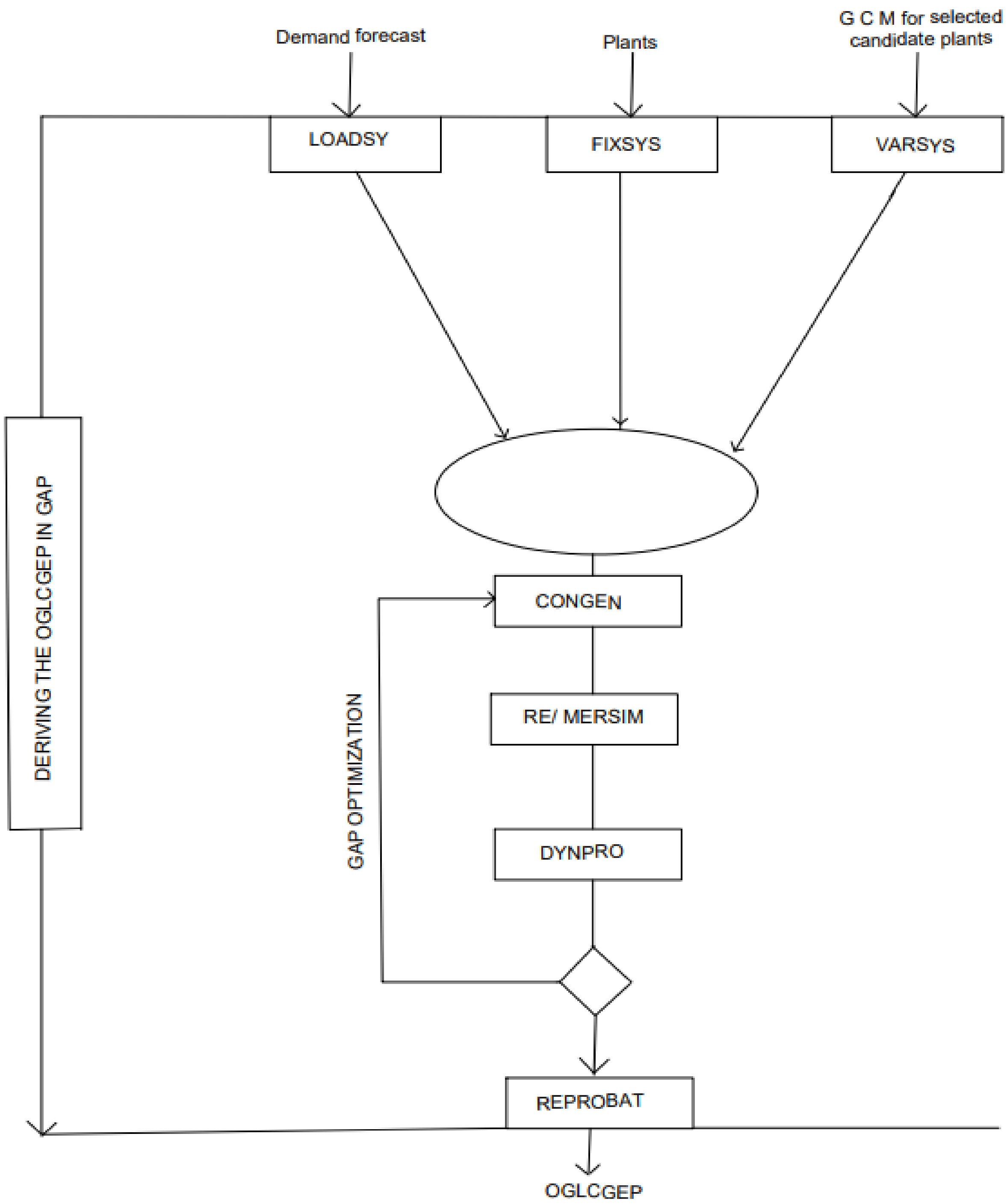

Figure 7: GEP Methodology for the study

3.2.1. Generation cost model (GCM)

The technical and economic aspects of power generation made up the majority of the GCM. The generation characteristics include both fixed and variable generation costs, as well as related parameters such as fuel cost, CO2 tax cost, operation cost, and maintenance cost. In addition, the following characteristics of the generation are included: interest during construction (IDC), total outage rate (TOR), interim replacement (IR), outage adjustment factor (OAF), and capital recovery factor (CRF). To evaluate the techno-economic characteristics of the possible generating plants, it was made in Microsoft Excel. The main parts of the generation cost model are shown in table 1.

Table 1: GCM Outline for all candidate generation plants [2]

CANDIDATES PLANTS	
Fixed cost and related parameters	**Variable costs and and related parameters**
• Installed capacity (MW) • Capital ($ & $/kW) • IDC • CRF • %IR • Fixed annual capital ($/kW.yr) • Fixed O&M cost ($/kW.yr) • Total fixed annual ($/kW.yr) • TOR • OAF • Annual fixed cost($/kW.yr &$/kWh)	• Fuel price ($kg) • Fuel cost ($/kWh) • Variable operation and maintenance cost ($/kWh) • Total variable cost ($/kW.yr & $/kWh)

Here are the important formula to formulate the generation cost model for the candidates generation plants.[2]

$$\text{Capital} = \text{Intalled capacity} \times \text{Installation cost} \tag{3.1}$$

$$\text{Fixed annual capital} = \text{Capital} \times \text{IDC} \times (\text{CRF} + \text{IR}) \tag{3.2}$$

$$\text{Total fixed annual cost} = \text{Fixed annual capital} + \text{fixed O\&M} \tag{3.3}$$

$$\text{OAF} = \frac{1}{1-\text{TOR}} \tag{3.4}$$

$$\text{Annual fixed cost} = \text{Total fixed annual cost} \times \text{OAF} \tag{3.5}$$

Each candidate plant's annual generation cost (AGC) is evaluated using the GCM as a function of the annual variable cost (AVC), with the annualized fixed cost (AFC) being held constant.

These cost factors are shown for the candidates in the AGC expression in Equation 3.6. The annual variable cost is represented by the slope of this linear equation, and the annualized fixed cost is represented by the intercept [2].

$$AGC = AVC \times \text{Capacity factor} + AFC \tag{3.6}$$

3.3.Green candidate generation plants quantification for GLCGEP

The level of green house gas emission by technology and the least cost for electricity generation were considered for selecting green and least cost candidate plants. Mixed integer linear programming with Matlab was used to determine the least cost candidate plants.

3.3.1. Green house gas emission

According to a study conducted by the National Renewable Energy Laboratory (NREL) on greenhouse gas emissions from electrical power generation sources, emissions from renewable sources are estimated to be less than 200 gCo2 e/kWh, which is lower than emissions from other technologies. The life cycle greenhouse gas emission estimates for a few different electricity generation, storage, and carbon capture-integrated technologies are displayed in the figure 8. According to this study, the best option for producing green electricity is renewable electrical energy sources [24].

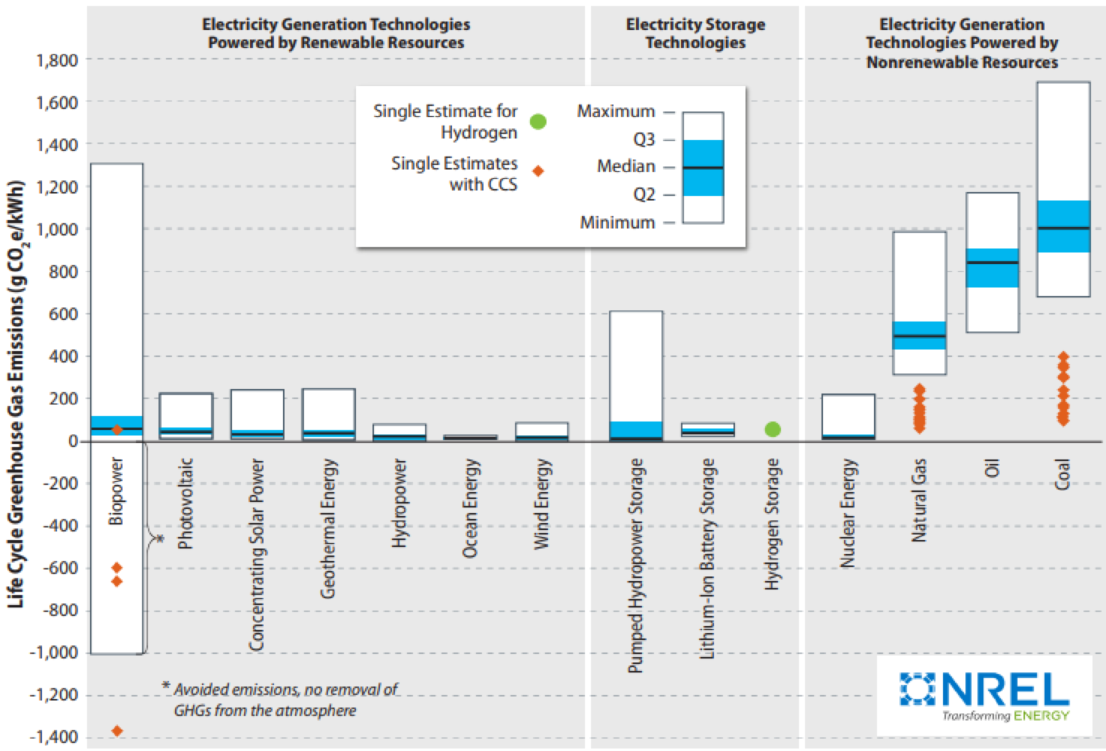

Figure 8: Greenhouse gas emission estimates for electricity generation technologies. [24]

3.3.2. Mixed integer linear programming (MILP)

A mixed integer linear programming (MILP) problem is an optimization problem that includes a linear objective function and linear constraints with integers as well as continuous decision variables.

By using matlab as a simulating tool, the model is solved with MILP having the general form bellow:

$$\text{Min } f(x) \text{ such that } \quad \begin{aligned} &x(\text{intcon}) \text{are integers} \\ &A\,x \leq b \\ &Aeq.x = beq \\ &lb \leq x \leq ub \end{aligned}$$

Where f(x) is an objective function, x stands for variables which may be all integers or some of them. A, Aeq, b and beq for matrix of inequality constraints, matrix of equality constraints , equality vector and inequality vector respectively. Then lb and ub stand for variable lower bound and upper bound respectively. In this model intlinprog was used as a solver.
The research shows that the average cost of production per kW in USD for solar, hydro power, geothermal, methane gas power and peat power are estimated to be 2000,2200,2600,1900 and 2010 respectively [25].

3.3.2.1. Objective function

In this study the total cost of generation per kw is to be minimized and formulated into a single-objective optimization problem presented as

$$\text{Min C} = 2200x + 2010y + 1900z + 2000n + 2600m \qquad 3.10$$

Where C stands for the total average cost of electrical power generation per kw, x, y, z, n and m stand for the electrical power produced from: hydroelectric power, peat, methane gas, solar and geothermal electric power respectively. Then 2200, 2010,1900,2000 and 2600 are the cost of electrical power generation per kW respectively as mentioned above.

3.3.2.2. Constraints

The study done by Asemota on electrical power sector in Rwanda in 2018 showed the total potential for hydropower, methane, peat deposits and geothermal power in the table 2.

Table 2: Installed power capacity by 2017 and total potential in MW. [25]

Power supply technology	Installed capacity(MW) by 2017	Total potential (MW)
Hydropower	100.7	313
Methane	30	480
Peat deposits	15	300
Geothermal power	N/A	520
Thermal power	57.8	N/A
Solar	12.08	N/A
Total	**216**	**1613**

The data collected shows that the current installed capacity is 353.4MW. For solar the upper boundary is estimated basing on its percentage energy mix with an assumption that the solar power percentage in Rwanda energy mix does not change during the planning horizon.

Table 3: Installed power capacity by September 2023 and total potential in MW

Power supply technology	**Installed capacity(MW) by September 2023**	**Total potential (MW)**
Hydropower	109.66	313
Methane gas	30	480
Peat fired PP	85	300
Geothermal power	N/A	520
Thermal power	58.8	N/A
Solar	12.05	N/A
Import & Shared	58.1	N/A
Total	**353.4**	**1613**

The sum of electrical power produced by individual technology should be less than or equal to the total potential available. It should also be greater than or equal to the current electrical power produced.

$$354 \leq x + y + z + n + m \leq 1613 \qquad 3.11$$

Considering the current installed capacity as of end September 2023 shown in the table 3, the boundaries for hydroelectric power, peat, methane gas, solar and geothermal electric power was set as follow:

$$110 \leq x \leq 313 \qquad 3.12$$

$$85 \leq y \leq 300 \qquad 3.13$$

$$30 \leq z \leq 480 \qquad 3.14$$

$$12 \leq n \leq 64 \qquad 3.15$$

$$0 \leq m \leq 520 \qquad 3.16$$

3.4 Case study load forecast with quadratic trend regression

The Quadratic trend regression is expressed by $Y = a_0 + a_1x + a_2x^2$.The constants a_0, a_1 and a_2 were solved by using matrix relation shown below.

$$\begin{matrix} \sum_{i=1}^{n} yi \\ \sum_{i=1}^{n} xiyi \\ \sum_{i=1}^{n} x_i^2 yi \end{matrix} = \begin{matrix} n & \sum_{i=1}^{n} xi & \sum_{i=1}^{n} x_i^2 \\ \sum_{i=1}^{n} xi & \sum_{i=1}^{n} x_i^2 & \sum_{i=1}^{n} x_i^3 \\ \sum_{i=1}^{n} x_i^2 & \sum_{i=1}^{n} x_i^3 & \sum_{i=1}^{n} x_i^4 \end{matrix} \times \begin{matrix} a_0 \\ a_1 \\ a_2 \end{matrix} \qquad 3.17$$

The matrix form can be written as: B = AZ

Where, B is the peak load output matrix in the equations, A is the coefficient matrix of the equations and Z is the required constant matrix. The matrix Z is found by: $Z = A^{-1}B$

By using the collected data for historical national peak demand for 8 years the table below is developed. The data recorded appear on appendix A

Table 4: Required values to find the coefficients of the equations

Years(X)	**Peak load in MW (Y)**	**X^2**	**X^3**	**X^4**	**X*Y**	**X^2*Y**
1	119.1	1	1	1	119.1	119.1
2	124.6	4	8	16	249.2	498.4
3	138.7	9	27	81	416.1	1248.3
4	140.6	16	64	256	562.4	2249.6
5	151	25	125	625	755	3775
6	164.4	36	216	1296	986.4	5918.4
7	178.7	49	343	2401	1250.9	8756.3
8	201.46	64	512	4096	1611.68	12893.44
∑36	**∑1218.56**	**∑204**	**∑1296**	**∑8772**	**∑5950.78**	**∑35458.54**

Using the table 4 the equation 3.17 may be written as:

$$1218.56 = 8a_0 + 36a_1 + 204a_2$$

$$5950.78 = 36a_0 + 204a_1 + 1296a_2$$

$$35458.54 = 204a_0 + 1296a_1 + 8772a_2$$

This system of equation was solved by using Matlab (as shown in appendix 2) to find out the values for a_0, a_1 and a_2 . The result was: a_0=118.32 , a_1=1.48, a_2=1.07. The quadratic trend regression equation became $Y = 118.32 + 1.48x + 1.07x^2$. The table 5 shows the actual peak load for 8 years from 2015 to 2022 and predicted peak load by quadratic trend regression from 2015 to 2022. The actual peak load was the data collected from energy utility corporation limited EUCL as appearing on appendix 3.

Table 5: Actual and predicted peak load from 2015 to 2022

Years	Actual peak load (MW)	Predicted peak load (MW)
2015	119.1	121.65
2016	124.6	128.63
2017	138.7	144.21
2018	140.6	147.59
2019	151	159.47
2020	164.4	174.35
2021	178.7	190.13
2022	201.46	214.37

The prediction by quadratic trend regression shows that in the first four years actual and predicted peak are almost the same only differ within the last four years. In 2022 the actual peak was 201.46MW and predicted peak was 214.37 this present the difference of 13 MW four 8 years.

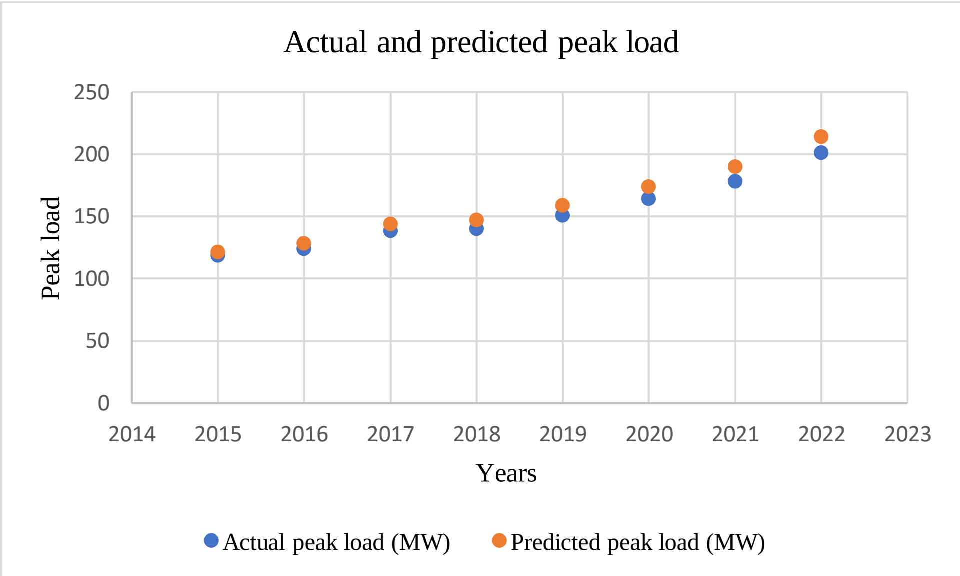

Figure 9: Actual and predicted peak load by quadratic trend regression from 2015 to 2022

3.5. Simulating the GLCGEP

In this study, the generation analysis (GAP) tool was used to simulate the data. There are three input modules that make it up. Among them are the variable system (VARSYS), fixed system (FIXSYS), and load system (LOADSY). As seen in figure 7, the modules contain the generation cost model (GCM) for the quantified candidate plants, the demand forecast, and the committed and existing generation plants. The data collected was used to determine the committed generation plants that are currently in operation, as shown in Appendix 4, and Microsoft excel was utilized to construct the GCM. The demand forecast was estimated through the use of quadratic trend regression.

CHAPTER FOUR: RESULTS AND DISCUSSION

4.1. Introduction

This chapter provides an overview of the chosen green candidate plants for generation expansion planning (GEP). Using quadratic trend regression, the national peak demand forecast up to 2038 was determined. Using the generation analysis planning (GAP) tool, the best GLCGEP based on the green candidates was presented. This chapter also established a comparison between the least cost power development plan (LCDP) and the GLCGEP, which was completed by REG in 2020.

4.2. The result for quantifying the least cost candidate generation plants

To solve the optimization problem shown in equation 3.11 up to 3.16, the mixed integer linear programming (MILP) with Matlab was used.

The result shows that 140MW for hydropower, 80MW for peat, 98MW for methane gas, 12 MW for solar and 0 MW geothermal electric power are the optimum candidates for the entire generation mix. The candidates present 42% ,24%, 30% and 4% respectively. The matlab codes and results are presented in appendix 1.

4.3. Generation cost model (GCM) for the selected candidates plants

Microsoft excel was used to create the generation cost model (GCM), which primarily consists of economic and technical aspects of power generation, for quantified candidate generation plants. Fixed generation costs, interim replacement (IR), total outage rate (TOR), outage adjustment factor (OAF), interest during construction (IDC), and capital recovery factor (CRF) for the candidate plants are all included in the GCM. The GCM was created by utilizing equations 3.1 up to 3.6. The generation plant candidates' GCM is shown in Table 6. The factors used for producing the generation cost model in excel sheet are found in appendix 5. Those factors are average values which may change according to the size of the plants.[2]

Table 6: Generation cost model (GCM)

Configuration n x MW	Hydropower 1x 42	Peat power 1 x24	Methane gas 1x30	Solar PV 3x4
Capacity (MW)	42	24	30	12
Fixed cost				
Capital ($) x$10^3$	92400	48240	57000	24000
Capital ($/kW)	2200	2010	1900	2000
IDC Factor	1.09	1.13	1.07	1.13
Annuity factor (C.R.F)	0.081	0.093	0.101	0.111
Interim replacement (%)	0.8	0.92	0.35	0.63
Fixed annual capital($/Kw/yr)	2112.6	2300.8	916.8	1674.6
Fixed O&M costs ($/kW/yr)	21	63	12	39
Total fixed annual cost ($/kW/yr)	2133.6	2363.8	928.8	1713.6
Total outage rate (TOR)	0.096	0.156	0.078	0.091
Outage adjustment factor (OAF)	1.106	1.185	1.085	1.1
Annual fixed cost ($/kW/yr)	2359.7	2801.1	1007.7	1885
Annual fixed cost ($/kWh)	0.26	0.32	0.115	0.215

The variable cost is mostly affected by fuel cost. In this study the selected candidates do not use fuel. Therefore the variable cost was ignored.

The findings indicate that all of the potential generation plants had significantly different annual fixed costs. 30 MW of methane gas had the lowest annual fixed cost of 1007.7$/kW/yr, while the 24 MW Peat power plant had the highest annual fixed cost of US$2801/kW/yr. That is due to methane gas low installation cost and its low interest during construction factor.

4.4 The result for load forecast with quadratic trend regression

The load forecast was calculated by quadratic trend regression which is expressed by $Y = a_0 + a_1x + a_2x^2$. The constants a_0, a_1 and a_2 were solved by using matrix relation 3.17. The constants a_0, a_1 and a_2 were found to be 118.32, 1.48, and 1.07 respectively as shown in appendix 2. The table 7 shows the actual peak load for the period from 2015 to 2022. and predicted peak load for the period from 2015 to 2038.

Table 7:The actual peak load from 2015 to 2022 and predicted peak load by quadratic trend regression from 2015 to 2038

Years	Actual Peak Load (MW)	Predicted Peak Load (MW)
2015	119.1	121.65
2016	124.6	128.63
2017	138.7	144.21
2018	140.6	147.59
2019	151	159.47
2020	164.4	174.35
2021	178.7	190.13
2022	201.46	214.37
2023	--	218.31
2024	--	240.12
2025	--	264.07
2026	--	290.16
2027	--	318.39
2028	--	348.76
2029	--	381.27
2030	--	415.92
2031	--	452.71
2032	--	491.64
2033	--	532.71
2034	--	575.92
2035	--	621.27
2036	--	658.76
2037	--	700.39
2038	--	750.16

The result shows that in 2022 the actual peak load was 201.46 MW while the predicted peak load by quadratic trend regression was 214.3 MW. There was a difference of 12.8MW which present 6% deviation. It is a good prediction as it goes slightly above the actual peak load. By 2038, the result shows that the predicted peak load is 750.16 MW.

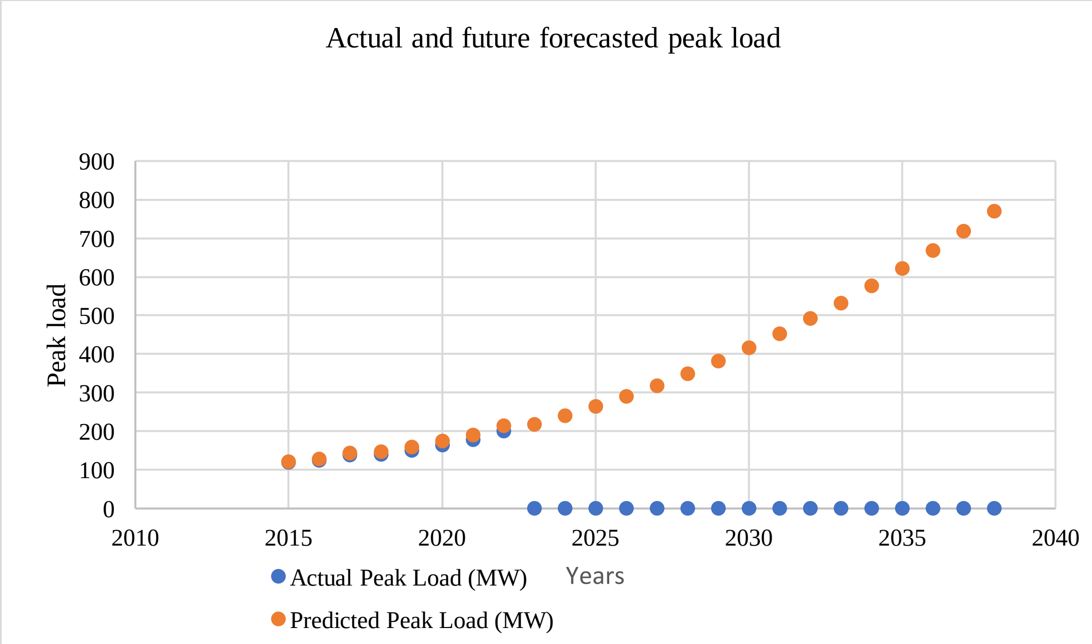

Figure 10: Actual and future forecasted peak load by quadratic regression

The result shows that in the first three years the actual peak and predicted peak load overlap each other then after from 2019 predicted peak load goes slightly above the actual peak load.

4.5. The optimal GLCGEP based on the green candidate power plants for the case study.

4.5.1. Capacity Mix

For the planning period, the best annual capacity addition solution for the chosen green candidate plants was found. The annual schedule for the addition of green power capacity is shown in Table 8. Natural gas and peat were added to supplement the increased capacity of green power. The findings indicate that the starting capacity for hydropower was 109.6 MW, the hydropower capacity increased gradually to a total of 277.6 MW by 2038 as presented by table 9. Hydropower had the highest additions of 168MW while solar PV had the lowest additions of 72MW over the hole planning horizon.

Table 8: Green power capacity addition schedule in MW

Year	Hydropower (42MW)	Peat power (24MW)	Methane gas (30MW)	Solar PV (4MW)	Total added capacity (MW)
2023	--	--	--	--	0
2024	1X42	--	--	--	42
2025	--	--	--	--	0
2026	--	--	--	--	0
2027	--	1x24	--	--	24
2028	--	--	1x30	--	30
2029	--	1x24	--	--	24
2030	--	--	--	3x4	12
2031	--	1x24	--	--	24
2032	--	--	1x30	3x4	42
2033	--	--	1x30	--	30
2034	1X42	1x24	--	--	66
2035	--	--	--	3x4	12
2036	--	2x24	--	6x4	72
2037	--	--	2x30	3x4	72
2038	2X42	--	--	--	84
Total	**168**	**144**	**150**	**72**	**534**
%	**31.4**	**26.9**	**28**	**13.4**	**100**

The optimal GLCGEP was found once the capacity additions were incorporated into the current system. The ideal GLCGEP capacity for the case study during the planning horizon is displayed in Table 9. According to the findings, in the base year, there was a peak demand of 218.3 MW, and the generation capacity was 353.2 MW. The capacity was predominated by hydropower (31%) and peat fired power (24.1%) at 61.8% reserve margin. The result also shows that in the last year of planning horizon (2038) the generation capacity is 887.2 MW at a peak demand of 750.1 MW. In this year the capacity was still dominated by hydropower (31.3%) and peat fired power (25.8%) at almost 18.3% reserve margin.

Table 9: Optimal GLCGEP Capacity (MW)

Year	**Hydropower (MW)**	**Peat power (MW)**	**Methane gas (MW)**	**Solar PV (MW)**	**Thermal power (MW)**	**Import & shared (MW)**	**System's capacity (MW)**	**Peak load (MW)**	**% Reserve margin**
2023	109.6	85	29.7	12	58.8	58.1	353.2	218.31	61.8
2024	151.6	85	29.7	12	58.8	58.1	395.2	240.12	64.6
2025	151.6	85	29.7	12	58.8	58.1	395.2	264.07	49.7
2026	151.6	85	29.7	12	58.8	58.1	395.2	290.16	36.2
2027	151.6	109	29.7	12	58.8	58.1	419.2	318.39	31.7
2028	151.6	109	59.7	12	58.8	58.1	449.2	348.76	28.8
2029	151.6	133	59.7	12	58.8	58.1	473.2	381.27	24.1
2030	151.6	133	59.7	24	58.8	58.1	485.2	415.92	16.7
2031	151.6	157	59.7	24	58.8	58.1	509.2	452.71	12.5
2032	151.6	157	89.7	36	58.8	58.1	551.2	491.64	12.1
2033	151.6	157	119.7	36	58.8	58.1	581.2	532.71	9.1
2034	193.6	181	119.7	36	58.8	58.1	647.2	575.92	12.4
2035	193.6	181	119.7	48	58.8	58.1	659.2	621.27	6.1
2036	193.6	229	119.7	72	58.8	58.1	731.2	658.76	11.0
2037	193.6	229	179.7	84	58.8	58.1	803.2	700.39	14.7
2038	277.6	229	179.7	84	58.8	58.1	887.2	750.16	18.3
%	**31.3**	**25.8**	**20.2**	**9.4**	**6.6**	**6.5**	**100**		

4.5.2. Energy Mix

Over the span of the planning horizon, it was anticipated that the energy generated for the optimum GLCGEP would increase gradually while still satisfying the necessary demand. The optimum national energy mix for GLCGEP is shown in Figure 4.5. The findings indicate a steady increase in the energy supply from 1995.1 GWh in the base year to 5006.2 GWh in 2038. The significant increase in energy will occur in 2038 with an increment of 404.6 GWh. That is due to the schedule of 84MW increment from hydropower in that year. The optimal GLCGEP national energy mix is calculated considering the capacity factor of each electrical power technology. The calculation was done with assumption that the current average capacity factor will not under go the significant change. The average capacity factor considered are 55% for Hydropower, 75% peat power ,85% methane gas 85% import and shared power, 22% solar PV and 45% for thermal power.

Table 10: The optimal GLCGEP national energy mix from 2023 to 2038

Year	Hydropower (GWh) at 55% cap. Factor	Peat power (GWh) at 75% cap. Factor	Methane gas (GWh) at 85% cap. Factor	Import & shared (GWh) at 85% cap. Factor	Solar PV (GWh) at 22% cap. Factor	Thermal power (GWh) at 45% cap. Factor	Total energy (GWh)
2023	528.05	558.4	221.1	432.61	23.13	231.79	1995.1
2024	730.4	558.4	221.1	432.61	23.13	231.79	2197.4
2025	730.4	558.4	221.1	432.61	23.13	231.79	2197.4
2026	730.4	558.4	221.1	432.61	23.13	231.79	2197.4
2027	730.4	716.1	221.1	432.61	23.13	231.79	2355.1
2028	730.4	716.1	444.5	432.61	23.13	231.79	2578.5
2029	730.4	873.8	444.5	432.61	23.13	231.79	2736.2
2030	730.4	873.8	444.5	432.61	46.25	231.79	2759.4
2031	730.4	1031.4	444.5	432.61	46.25	231.79	2917
2032	730.4	1031.4	667.9	432.61	69.38	231.79	3163.5
2033	730.4	1031.4	891.2	432.61	69.38	231.79	3386.8
2034	932.8	1189.1	891.2	432.61	69.38	231.79	3746.9
2035	932.8	1189.1	891.2	432.61	92.51	231.79	3770
2036	932.8	1504.5	891.2	432.61	138.75	231.79	4131.7
2037	932.8	1504.5	1338	432.61	161.88	231.79	4601.6
2038	1337.4	1504.5	1338	432.61	161.88	231.79	5006.2

The result shows that the energy from thermal (diesel), import and shared power are constant during the period of planning. The energy from thermal (diesel) will be used as the last option; this means it is used as reserved electrical energy.

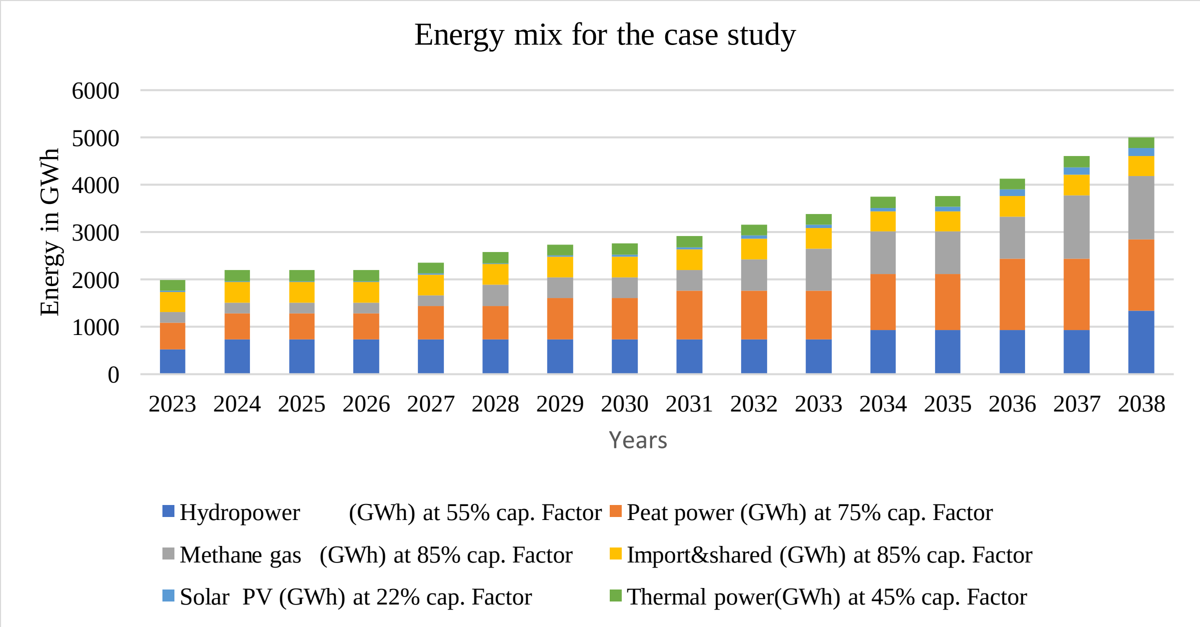

Figure 11:The optimal GLCGEP national energy mix for the case study

4.5.3 Economic generation

For the optimal GLCGEP, the average electrical energy tariff per unit generated was US$ 0.16/kWh. The optimal GLCGEP long-run marginal cost (LRMC), or the price of extra electricity produced over the planning horizon, is displayed in Table 10. The LRMC at the end reflects the unit selling price for electricity where tax and interest are excluded. The result with table 11 showed that the operation and maintenance cost is 0.05$/kWh, the capital is 0.11$/kWh and the total gave LRMC.

Table 11: The ideal long-run marginal cost (LRMC) of the GLCGEP

Year	**System's capacity**	**Total energy (GWh)**	**Opern. & Maint. cost (M$)**	**Capital cost (10^3$)**	**System total cost(10^3$)**
2023	353.2	1995.08	441.5	0	441.5
2024	395.2	2197.43	494	92400	92894
2025	395.2	2197.43	494	0	494
2026	395.2	2197.43	494	0	494
2027	419.2	2355.13	524	48240	48764
2028	449.2	2578.53	561.5	57000	57561.5
2029	473.2	2736.23	591.5	48240	48831.5
2030	485.2	2759.35	606.5	24000	24606.5
2031	509.2	2916.95	636.5	48240	48876.5
2032	551.2	3163.48	689	81000	81689
2033	581.2	3386.78	726.5	57000	57726.5
2034	647.2	3746.88	809	140640	141449
2035	659.2	3770.01	824	24000	24824
2036	731.2	4131.65	869	144480	145349
2037	803.2	4601.58	921.5	138000	138922
2038	887.2	5006.18	974	184800	185774
		$/kWh **Op.&Maint.** **Capital** **LRMC**	 **0.05** **0.11** **0.16**		

4.6. Comparative evaluation of the optimum GLCGEP and LCPDP

Rwanda Energy Group (REG) in December, 2022 conducted a study on the least cost power development plan (LCPDP). As methodology they used the Model for Energy System Supply Alternatives and their General Environmental Impacts (MESSAGE). In this study the new generation capacity, the optimal time to add new generation capacity and the supply technology were determined over 20years ahead. In this study however, the Generation Cost Model (GCM) was not considered as a result there was no estimation for long run marginal cost for the electrical energy added on the system.

In this study the result for the ideal GLCGEP shows that long run marginal cost for the electrical energy added on the system was 0.16$/kWh as the base price tax and interest excluded.

In the base year, the optimal GLCGEP had an installed capacity of 353.4 MW the same for the least cost power development plan (LCPDP). The installed capacity increased to 887.2MW in 2038 while the installed capacity for LCPDP increased to 680MW in the same year. In the base year, the optimal GLCGEP considered 218 MW as the peak demand while the LCPDP considered 200MW as forecasted national peak demand however, for GLCGEP it increased to

750MW while on the other hand it increased to around 600MW by 2038. That made the difference of 150MW. For GLCGEP the energy consumption increased from 1995.1 GWh to 5006.2 GWh in the last year of planning horizon while on the other hand the energy rose from around 1000GWh to 3000 GWh in 2038.

Considering the new trends like electric vehicles, that technology is becoming increasingly popular as a more sustainable and cost-effective alternative to traditional gasoil-powered cars. Due to the fact that the cost of diesel is highly increasing with time, the electric vehicles development might increase significantly the electricity consumption in near future. Therefore the optimal GLCGEP can be a good alternative to meet the electricity demand.

CHAPTER FIVE: CONCLUSION AND RECOMMENDATION

5.1 Conclusion

The optimal green candidate plants namely: 42MW hydropower, 24MW peat, 30MW methane gas and 4 MW solar were determined as the optimal green candidate plants. In 2022 the actual peak load was 201.46 MW while the predicted peak load by quadratic trend regression was 214.3 MW. By 2038, the predicted peak load was 750.16 MW.

The generation capacity was 353.2 MW at a peak demand of 218.3 MW in the base year. The capacity was predominated by hydropower (31%) and peat (24.1%) at 61.8% reserve margin. By 2038, the generation capacity is predicted to reach 887.2 MW at a peak demand of 750.1 MW. In this year, the capacity is still dominated by hydropower with 31.3% and peat fired power with 25.8% at 18.3% reserve margin. The energy supplied is expected to rise from 1995.1 GWh in the base year to 5006.2 GWh in 2038. The operation and maintenance cost was 0.05$/kWh, the capital cost was 0.11$/kWh and the total gave long run marginal cost.

5.2 Recommendation

Since many hydropower power plants have limited water supplies, It is recommended to conduct research on how to implement pumped-storage hydropower plants. Doing so should boost the plants' generation and transmission efficiencies, which will increase the electrical power installed capacity in Rwanda.

It is also recommended to conduct a research on modelling power system stability with solar PV integrated in the Rwandan electrical network, as solar PV integration will reach 9.4% of total capacity mix by 2038.

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APPENDIX

1.Matlb codes

```
f=[2200;2010;1900;2000;2600];
A=[1,1,1,1,1;-1,-1,-1,-1,-1];
b=[1613;-354];
Aeq=[];
beq=[];
lb=[110;85;30;12;0];
ub=[313;300;480;64;520];
intcon=[1 2 3 4 5];
[x,fval,exitflag,output]= intlinprog(f,intcon,A,b,Aeq,beq,lb,ub)
% answer x=140 , y=80, z=98, n=12, m=0
```

2.3 by 3 equations Matlab solution

```
>> A=[8,36,204;36,204,1296;204,1296,8772]

A =

           8          36         204
          36         204        1296
         204        1296        8772

>> B=[1218.56;5950.78;35458.54]

B =

   1.0e+04 *

    0.1219
    0.5951
    3.5459

>> a=inv(A)*B

a =

  118.3207
    1.4867
    1.0710
```

3.Historical national peak demand from 2015 to 2023

Year/Month	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023
July	100.8	113.2	131	137.8	145.1	145	159.3	181.57
August	105.3	115.4	124.6	136.6	145.5	146.6	160.1	183.98
September	107.3	118.9	125.5	136.6	144.2	143.8	170.2	184.08
October	116.4	117.7	125.6	138.1	146.9	147.8	169.4	185.16
November	110.5	114.6	125.9	135.9	143.9	154.8	170.7	182.15
December	111.7	116.5	133.9	135.8	142.3	149.6	165.2	183.2
January	112.8	119	123.3	139.5	142.7	147.9	165.4	190.56
February	113.3	115.8	128.2	140.6	151	150.9	175.9	193
March	117.4	118.6	127.3	137	148.4	152	176.8	196.73
April	116.1	118.1	125.6	139.3	125.6	164.4	173.9	197.06
May	119.1	124.4	128.6	140.5	136.3	154.4	178.1	199.71
June	118	124.6	138.7	139.7	138.4	162.5	178.7	201.46
Annual peak	**119.1**	**124.6**	**138.7**	**140.6**	**151**	**164.4**	**178.7**	**201.46**
%	0.00%	4.62%	11.32%	1.37%	7.40%	8.87%	8.70%	12.74%

4.Capacity mix as of end September 2023

Capacity mix as of end September 2023			
Types	**Installed Capacity**	**Capacity %**	**Avrg. Capacity factor**
Hydropower	109.662	31.0%	55%
Thermal Power	58.8	16.6%	45%
Solar Power	12.05	3.4%	22%
Methane Gas	29.79	8.4%	85%
Import & Shared	58.1	16.4%	85%
Peat Fired PP	85	24.1%	75%
Total	**353.402**	**100%**	

5.Factors used for producing the generation cost model in excel sheet.

Factor type	Hydropower	Peat power	Methane gas	Solar PV
IDC Factor	1.09	1.13	1.07	1.13
Annuity factor (C.R.F)	0.08	0.093	0.101	0.111
Interim replacement (%)	0.8	0.92	0.35	0.63
Fixed O&M costs ($/kW/yr)	21	63	12	39
Total outage rate (TOR)	0.1	0.156	0.078	0.091
Outage adjustment factor (OAF)	1.11	1.185	1.085	1.1

6. Terms definition

Reserve margin (RM): The amount of unused available capability of an electric power system (at peak load for a utility system) as a percentage of total capability.

Life cycle GHG emission: The aggregate quantity of greenhouse gas emissions including direct and indirect emissions.

Economies of Scale: Refer to the cost advantage experienced by a firm when it increases its level of output. The advantage arises due to the inverse relationship between the per-unit fixed cost and the quantity produced. The greater the quantity of output produced, the lower the per-unit fixed cost.

Feed-in-tariffs: is a policy tool designed to promote investment in renewable energy sources. This means promising small-scale producers of the energy such as solar or wind energy an above-market price for what they deliver to the grid.

Interest During Construction: is the interest which is due on project financing loan facilities during the construction period, but which cannot be paid since the Borrower is not generating cash. This interest is generally added to the loan. Therefore it behaves like cost of construction.

7.Actual electricity tariff

New Electricity End-user Tariffs.

Rwanda Utilities Regulatory Authority (RURA), today announces new electricity tariffs which will be effective on Tuesday 21st January 2020. These tariffs replace the previous ones which were set on 13th August 2018.

The end-user electricity tariffs were reviewed in order to meet the required operational and investment expenditures for the utility (EUCL) mainly because of the activities related to the expansion and maintenance of the network.

The tariffs are reviewed as follows:

Customer	Consumption Block	Tariff (VAT Exclusive)- FRW/kWh	
		Existing	New Tariffs
Residential Customers	≤15 kWh per month	89	**89**
	]15-50] kWh per month	182	**212**
	>50 kWh per month	210	**249**
Non-Residential Customers	≤100 kWh per month	204	**227**
	>100 kWh per month	222	**255**
WTP & WPS	All	126	**126**
Telecom towers	All	185	**201**
Hotels	All	126	**157**
Health Facilities	All	192	**186**
Broadcasters	All	184	**192**
Small industries ≤ 22,000 kWh/Year	All	110	**134**

1