National University of Lesotho

Electricity transmission capacity expansion planning for Lesotho

Thaane Mokose (201701363)

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Abstract

Transmission Expansion Planning (TEP) is crucial in identifying the optimal timing, location, and scale of new transmission lines and substations to ensure a reliable energy supply to consumers. In Lesotho, the expansion of transmission and distribution networks faces considerable challenges due to the country's rugged, mountainous terrain, particularly in extending access to rural areas. However, the abundant potential for renewable energy generation from solar, wind, hydro and pumped storage provides a promising development pathway. Despite this potential, there is a significant lack of strategic planning in how Lesotho can expand its network to accommodate renewable energy projects while maintaining stability and reliability. This study utilized DIgSILENT PowerFactory to simulate network scenarios for 2023, 2030, and 2035, providing critical insights into potential congestion points when integrating new renewable generators into the grid. This study also provides critical insights into network stability and the necessity for strategic transmission line and substation expansion planning. The study aims to provide insight to Lesotho Electricity Company (LEC) as the transmission line operator to see where the network may encounter congestion when different generators are integrated into the network. Key renewable energy projects analysed include the 72 MW 'Muela Hydropower, 30 MW Ramarothole solar photovoltaic (PV), the 20 MW OnePower solar PV, the upgrade to 80 MW for Ramarothole, and the 66 MW Hirundo wind farms. The results show a 30% increase in transformer loadings from 2023 to 2030, with an additional 14% increase from 2030 to 2035, which highlights the growing demand for the existing infrastructure. Cost analysis for reinforcing the transmission infrastructure estimate the upgrade of transmission lines at USD 44,803,233.79 and transformer upgrades at USD 125,338,880.49. To meet the rising power demand and integrate renewable energy sources without compromising network stability, it is recommended that the Lesotho Electricity Company (LEC) invest in new power transformers at various substations to reinforce the existing transmission lines. This study provides the LEC with crucial guidance for strategic TEP, ensuring the nation's power grid can meet future energy needs while remaining stable and reliable.

Keywords: Renewable energy, transmission lines, reinforcing, stability, power grid.

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1. Introduction

1.1 Background

Planning for capacity expansion involves assessing the state of the power transmission system and identifying potential areas for growth and improvement [1]. Efficient expansion planning prevents blackouts and maintains the security of supply while also minimizing operation and maintenance (O&M) costs for grid operators [2]. Capacity Expansion Planning (CEP) stands as one of the important roles for state-owned electric utilities having a monopoly in the generation, transmission and distribution of electricity [3]. CEP is used as a scenario tool to model or forecast future generation and transmission over a wide range of load growth, decarbonization and economic scenarios so that the produced power does not cause transmission congestion [3]. The goal is to ensure that the electricity generated is transported to the appropriate locations in a timely and cost-effective manner to meet the demand for electrical energy. Planners use this approach to identify the lowest-cost plans that satisfy their planning constraints, which are typically defined by a planning reserve margin. The margin credits generation and demand-response resources are based on their ability to meet peak demand needs during hours of high risk to shed load.

Power systems that use renewable energy resources (RERs) may effectively tackle many issues, such as voltage instability, power quality, electrical losses and environmental contamination [4]. Since RERs were not originally intended for the grid, the generating and transmission networks must be expanded in order to support them. To satisfy the increasing load demand, the generating units must be chosen based on factors such as type, capacity and location. This process is known as generation expansion planning (GEP) and transmission expansion planning (TEP). Important variables in power system expansion include voltage magnitudes, power dispatch and electrical losses [4]. An accurate power loss assessment is necessary to measure the effects of RERs on the electrical system.

First, GEP uses a resource-based approach where the power-generating units are installed near their primary source, and the generated power is stepped up or down by a transformer and transmitted to the load centres using transmission systems [5]. The TEP determines when, where and how many new lines (and substations) need to be installed to ensure a sufficient level of energy supply for consumers. The transmission network is a crucial component of power systems, facilitating physical connection between generators and load centres and enabling the integration of generators with different characteristics. Despite liberalization, the transmission network remains a natural monopoly, ensuring supply security and investment in new assets through TEP [6]. While minimizing investment, operation, and interruption costs, TEP takes into account load growth, forecasted demand, reliability criteria, and new generator capacities [7]. When planning for transmission expansion, the location and when the transmission line should be built or improved are necessary. This is influenced by the reliability of electrical systems, the location of the power plant and the nearby load centres [5].

The mountainous terrain of Lesotho, a landlocked country, causes problems for grid developers to build new transmission and distribution lines in rural areas [8]. However, several studies show that Lesotho has the potential to generate power using renewable energy sources such as solar, wind, hydro and pumped storage [9]. These renewable energy sources have to be integrated into the grid in order to improve its operations, supply power and cater to the transmission paths to certain load centres. Nevertheless, the integration of generation facilities with the transmission power systems is crucial because transmission restrictions may affect the location and size of the new power-producing units [10].

As we transition to a power system with more wind and solar resources, it is becoming increasingly vital to approach the generation and transmission capacity expansion or modelling as a unified or integrated process. However, for many utilities and independent system operators0, such as the Lesotho Electricity Company (LEC), transmission planning and generation planning remain distinct and specialized procedures. In Lesotho, for example, as the system operator, LEC will be primarily concerned with transmission planning, while the Department of Energy (DoE), together with Lesotho Highlands Development Authority (LHDA) and Lesotho Electricity Generation Company (LEGCo) as the national generators, will be concerned with capacity development or generation planning.

1.2 Problem Statement

LEC has had exclusive control over the transmission, distribution and provision of electricity in Lesotho. With the recent installation of a 30 MW Ha Ramarothole solar photovoltaic (PV) plant, the local generation capacity has increased from 74.6 MW to 104.6 MW in 2023. According to Rateele and Thamae [11], this recently introduced 30 MW Ha Ramarothole solar PV farm can reduce energy imports by 22.3%. However, the electricity demand in the country is still not met since the peak demand in 2022 was 203.48 MW. The remaining power shortage of 98.88 MW or greater is addressed by importing energy from South Africa via Eskom and from Mozambique via Electricidade de Mozambique (EdM) [9]. The research problem is the insufficient capacity of Lesotho's transmission network to manage growing power generation and demand.

The country imports electricity using bilateral contracts that enable the LEC to secure transmission paths in advance. These contracts come with high reliability costs, which lead to LEC setting high charges for customers and end-users. Although the transmission paths are secured for now, the local power generation has to be improved due to the increasing demand for electricity in the country and the worsening power shortages in South Africa and the region. Several utility-scale power plants based on solar, wind and hydropower are already planned at different locations around the country, and they will have to be effectively evacuated by the transmission network to the appropriate load centres. For instance, LEC has commissioned a new 132 kV transmission line to strengthen the grid and evacuate the power to a new substation at Ha Mofoka due to the anticipated increase in line loadings for the old 132 kV Ramarotholeto-Mazenod transmission line as the Ramarothole solar PV farm capacity gradually increases to its planned maximum capacity of 90 MW. For the upcoming planned utility-scale generations across the country, the capacities of the existing old transmission lines and substations are likely to be inadequate. Hence, this study plans to undertake TEP to consider the technical operation for evacuating the power, as it is critical for meeting the future load forecast, while also considering the variations in the line loadings and possible new line reinforcements.

1.3 Research Questions and Objectives

This study aims to assess the capacity of the existing transmission network to handle the proposed generations and plan possible upgrades and/or new transmission paths so that the power from the planned renewable sources (hydropower, solar, and wind energy) can be evacuated to the grid without causing transmission congestion or disruptions.

The research questions to be answered by the study are:

i. What will happen if Lesotho’s local generation stays stagnant and there’s no transmission upgrading of the Eskom or Southern African Power Pool (SAPP) interconnection?
ii. How can the planned new generation be evacuated from the generation sources, and which transmission paths should they take?
iii. What happens if Lesotho can generate power to its potential and there’s a need for exporting; are the already existing transmission lines able to handle the power?
iv. What is the most economical way of evacuating power?

The objectives of the study are as follows:

i. To use DIgSILENT Power Factory to establish the points of congestions and voltage fluctuations on the network.

ii. To find out how the Lesotho electricity grid network will operate after including all generations and transmission lines for the base year 2023.

iii. To identify the stability and line loadings of the existing transmission network with the existing generations.

iv. To identify the scenarios for when there is an increasing need for imports (due to stagnant local production) and when the upcoming local generation materializes and the power has to be evacuated to meet the demand.

v. To find the most economical way to evacuate the power from the generation sources to load centres.

1.4 Justification

As of 2022, the electrification rate in Lesotho had reached 52%, and the remaining 48% were mostly rural households in remote areas of the country [12]. To meet the demand, both the generating and transmission infrastructures must be expanded. Renewable energy resources are currently significant in expansion planning, not only for generating clean power but also for maximizing local natural resources [5]. Lesotho aims to achieve 375 MW of electricity through renewable energy sources by 2030 and to export the excess energy to the SAPP [13]. Several studies show that Lesotho has the potential for RES such as wind energy (mean wind speed of 8 m/s), which, from a few locations, may produce capacities ranging from 20 to 134 MW, such as at Lets'eng, Sani and Masitise [14]. In addition 'Muela and the mini hydropower plants at Mants'onyane, Mokhotlong, Tsoelike and Semonkong are currently utilizing only 17% of Lesotho's 450 MW hydropower potential [15]. Moreover, Taele et al. suggest that Lesotho can produce electricity using solar PV with an average global solar radiation of 5.5 to 7.2 kWh/m^2 [16]. Other projects are also being commissioned in Lesotho. For example, the 80 MW solar farm at Ha Ramarothole (30 MW phase 1 is already online and 50 MW phase 2 is to be constructed together with another 20 MW solar plant by OnePower). The upcoming wind projects include the one by Hirundo Energy with a capacity of 110 MW and about 262 MW for small scale and large scale hydropower [2]. These generation capacities can increase energy security in the country and minimize the current heavy dependence on imports.

The renewable energy generating facilities in the country are owned by independent power producers (IPPs), who sell the electricity to LEC, the sole transmitter and distributor of electricity. Due to the intermittent nature of renewable energy sources, frequency variations and voltage stability cases have to be considered so that suitable transmission lines and transformers are chosen to handle such power. Transmission expansion planning will be critical to facilitating the green economy through the integration of renewable energy generation technologies and capacity expansion models can be used to guide the development of proactive transmission expansion projects [3]. The requirement to predict transmission expansion, based on future demand projections and generation expansion, necessitates proper representation of transmission value in the models. Knowing the projected cost of transmission paths for electricity from planned generators can help the decision-makers make informed choices on the path that is economically viable for upcoming generations. The power from the upcoming generators needs to be evacuated to certain substations or load centres so that it can be distributed to the customers or end-users. This study may contribute to the national integrated resources planning efforts by investigating how power can be evacuated effectively from generation sources or imports to meet the ever-escalating electricity demand in Lesotho, considering the time when there is stagnant local electricity generation and when there is increasing or adequate local generation to start exporting electricity.

1.5 Report Structure

The rest of the dissertation report is organized as follows: Chapter 2 outlines the literature review of TEP, while Chapter 3 describes the methodology that will be carried out to undertake TEP through the DIgSILENT PowerFactory simulations. Chapter 4 provides the results and discussions of the model described in Chapter 3. Lastly, Chapter 5 concludes the study and gives recommendations for future research.

2 Literature Review

2.1 Recent Works on Transmission Line Planning

Network planners are currently confronted with a major obstacle in their efforts to develop a more suitable expansion plan. This challenge entails the need to efficiently and promptly increase the transmission capacity in order to accommodate future renewable energy sources (RES). In addition, it is crucial to maintain a secure and reliable electricity service for the customers, to promote competition and to ensure market efficiency [18]. In [18] the transmission expansion problem is addressed through the implementation of the line uprating techniques, such as the addition of new lines, voltage upgrading and line re-conductoring simultaneously. This approach results in a 5.1% reduction in total investment and a significant decrease in the environmental impact of the grid. In addition, it allows for the integration of renewable energies in the future.

Hajebrahimi, Abdollahi and Rashidinejad [19] developed a multi-objective TEP issue in the energy market that incorporated demand response (DR), wind generation and network reliability. The goals are to minimize capital costs, mitigate congestion and reduce risk while also maximizing incentives for demand response participants. The generic algorithm was utilized to tackle the complex, large-scale nonlinear optimization issue [20]. In addition, a probabilistic analytical methodology known as the two-point estimate method was implemented to address the uncertainty associated with wind energy integration into the grid.

Mahdavi et al. [21] developed an approach that prioritizes network dependability in the design of generation-transmission growth, taking into account the effects of line maintenance, repair and loads. The economic advantage of line maintenance is determined by computing the entire cost of generation and transmission, both with and without the implementation of optimal maintenance operations. The reliability effect is determined by the cost of load shedding; the loss of load index is calculated. The model emphasizes the need for prompt and appropriate maintenance and repair measures to achieve long-term economic advantages.

Qiu et al. [22] successfully addressed the Generation and Transmission Expansion Planning (GTEP) problem by taking into account the uncertainties associated with wind generation and DR. This model achieved a reduction in the overall cost of the network by minimizing the loss of power caused by wind curtailment and improving the coordination between demand response and delivery of electricity. In contrast to the studies that employ deterministic security criteria, a novel technique was provided in [22], which utilizes an insecurity risk approach to quantify the degree of system security. This approach takes into account the frequency and severity of contingencies, providing network designers with a flexible framework.

2.2 Power System and Network Operations

Electrical Power system is a network of complex electrical components used to supply, transfer and consume electricity. The main supply of electrical power is done by power plants (renewable energy sources, nuclear, fossil fuels, etc.). To transfer this electric power, transmission lines and distribution lines are used until the required power reaches the consumers. Figure 1 shows the simplified diagram of the electrical power system from generation to consumption. Table 1 shows the practical voltage levels used around the world, from generation to secondary distribution. The generating plants are responsible for producing electricity by converting mechanical energy into electrical energy at low voltage levels (e.g., 11 kV to 13 kV) since it creates fewer stresses on the armature of the alternator. The voltage is too low for transmission over long distances [23]. Subsequently, a generator step-up transformer is employed at the producing station to amplify the voltage (e.g., from 11 kV to a maximum of 500 kV). This amplification allows for the efficient transfer of electrical energy across long distances while minimizing the losses during transmission. The step-up transformer increases the voltage of the generated electricity based on the length of the transmission line and the power capacity required for transmission. The transmission of electric power at a voltage of 132 kV is achieved using a 3-phase, 3-wire overhead transmission system extending to the periphery of the city. This forms part of the primary transmission, where transmission is always carried out by duplicate lines to ensure the continuity of the service.

Furthermore, at the receiving station of the primary transmission, there is a transmission substation with the step-down transformer, which drops the voltage (e.g. from 500 kV to 33 kV or 11 kV) so that it can be easily distributed to the load centres. The electric power is transported from this station to numerous substations throughout the city using a 3-phase, 3wire overhead system at a voltage of 33 kV. These substations are strategically situated at different sites in the city. This constitutes the secondary transmission. The secondary transmission lines conclude at the substation located in the city, where the voltage is decreased from 33 kV to 11 kV in order to become a component of the primary distribution. The 11 kV power lines are positioned beside the highways to provide electricity at 11 kV to customers that require more than 50 kW. This electricity is then transferred to their substation for further distribution.

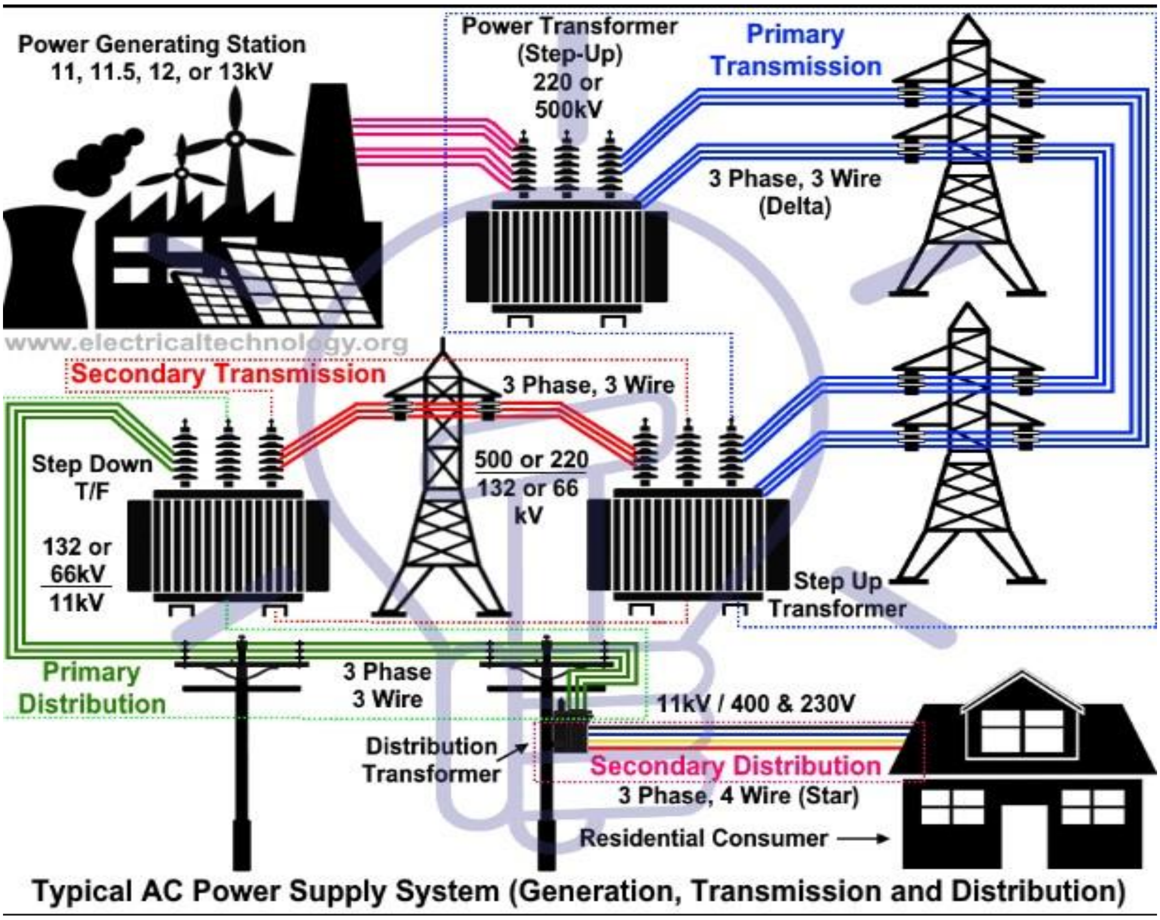
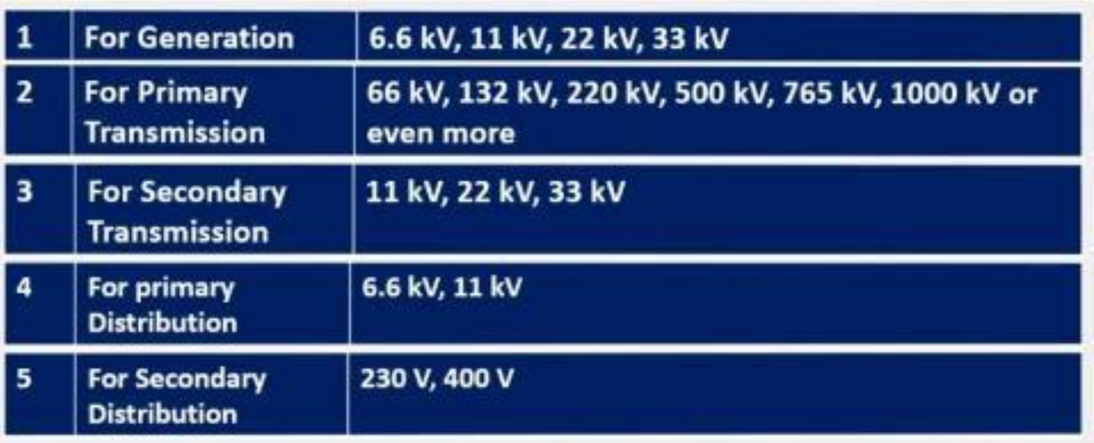


Figure 1: Electrical power system and network operations [23].

Before the power reaches the customers (Industries, households, hotels, etc.), the distribution transformer further steps down the voltage to a less harmful voltage (e.g. 11 kV to 400V or 230 V), 3-phase, 4-wire for secondary distribution using medium and low voltage distribution circuits that easily interconnect transmission lines with distribution lines. The electric power from the primary distribution line is delivered to Pole Mounted Substations (PMT), which are located near the consumer’s localities where it is stepped down. The voltage across any pair of phases is 400 V, whereas the voltage between any individual phase and neutral is 230 V. The voltage between any two of the three phases and the earth is 1.73 times greater than the voltage of any one phase to the earth. Each of the three phases of a 132 kV transmission circuit is capable of conveying 300 A of current for a total power transmission of 70 MW. At 11 kV, a distribution circuit is capable of delivering 3 MW of electricity through its three phases at a current of 150 Amps each. The power transmission capacity of the final distribution circuit is 150 kW, achieved by operating at a voltage of 400 V and managing a current of 200 A in each of its three phases [24].

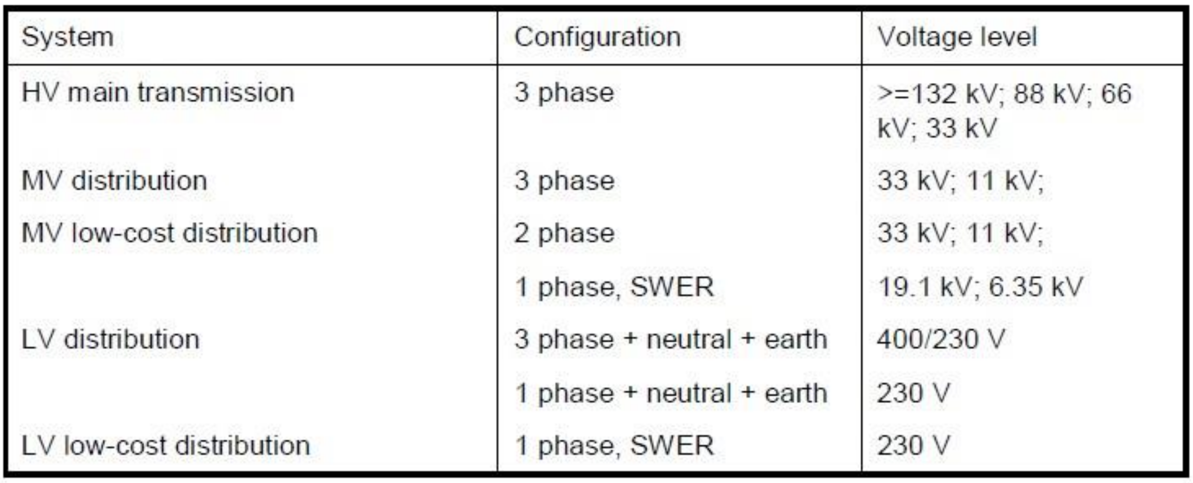
Table 1: Practical voltage levels of a power system [25].



1	For Generation	6.6 kV, 11 kV, 22 kV, 33 kV
2	For Primary Transmission	66 kV, 132 kV, 220 kV, 500 kV, 765 kV, 1000 kV or even more
3	For Secondary Transmission	11 kV, 22 kV, 33 kV
4	For primary Distribution	6.6 kV, 11 kV
5	For Secondary Distribution	230 V, 400 V

Table 2 shows the standard voltages chosen for transmission and distribution in the LEC network. The transmission voltages covered by LEC's networks include 132 kV, 88 kV, 66 kV, and 33 kV. The highest transmission system voltage in Lesotho is 132 kV which is used to transmit power over long distances from generation to different substations. The 88 kV is used for electricity imports from South Africa (Eskom) and Mozambique (EDM). The 66 kV voltage is utilized for locally generated power, while the 33 kV voltage is employed for subtransmission and distribution purposes.

Table 2: Standard voltage levels for the Lesotho network [26].



System	Configuration	Voltage level
HV main transmission	3 phase	>=132 kV; 88 kV; 66 kV; 33 kV
MV distribution	3 phase	33 kV; 11 kV;
MV low-cost distribution	2 phase	33 kV; 11 kV;
	1 phase, SWER	19.1 kV; 6.35 kV
LV distribution	3 phase + neutral + earth	400/230 V
	1 phase + neutral + earth	230 V
LV low-cost distribution	1 phase, SWER	230 V

The 33 kV and 11 kV distributions are used for long distribution line feeders, which supply power to small clusters and settlements. Most of the distribution transformers are pole-mounted to reduce costs. The transmission lines are overhead lines, with protection from lightning by ground wire. The transmission system in Lesotho was mostly established in the western half of the nation, which has a less hilly terrain. This includes the Northern and South Western regions, where the main grid is well-established. Qach's Neck and Semonkong are the few regions that receive electricity from sources other than the primary power grid. The two lines originating from South Africa are currently operational and serve as an essential component of the primary transmission system [26], [27].

2.3 Transmission Lines in a Power Network

Transmission lines in the power network cover the transport of high voltage (HV) and the despatch of electricity from various sources through an integrated, national network to unidirectional meters, to distributors or special customers who are in a position to take power directly [28]. Transmission networks can link up adjacent national grids so that there are interconnections with other countries, which are essential for power trade and which enhance the security of supply and reliability in the country [29]. The transmission of electric power between two points on a transmission network is constrained by several transfer limits [30], [31], [32]. These transfer limits include thermal limits, voltage limits and stability limits. When such a limit is reached, the system is said to be congested. According to Chen [33], allocating load curtailments caused by transmission congestion to each faulty component is the best way to notice weak positions of transmission congestion. Many factors must be considered while managing transmission congestion-related TEP such as the operating cost due to congestion, the available transfer capability, the transmission surplus capacity and the loading of the transmission lines [34]. If the issue is to be resolved quickly, the line loadings on the overloaded transmission lines need to be reinforced or renewed; the reinforcement/renewal may be capitaldemanding. Therefore, developers need to plan for the appropriate capacity and line loading in order to assess the investment value. The determination of a new transmission line to build when the line loadings are violated is communicated between the transmission grid owners and the regional reliability coordinators [35]. The planning process takes into account several issues, including the changes in the load and proposed new generators.

Transmission lines are typically extra-high-voltage (EHV) or ultra-high-voltage (UHV) alternating current (AC) lines or high-voltage direct current (HVDC), depending on the distance that the transmission lines will cover [36]. EHV and UHV AC lines are commonly used to transport energy over long distances, typically from hundreds of kilometers to several thousand kilometers. These lines operate at high voltages such as 220 kV, 400 kV, 500 kV, or even higher [36]. AC power transmission is preferred for shorter distances due to the ease of voltage conversion and is used in AC power systems. UHV AC lines, operating at voltages above 800 kV, are used for transmission over very long distances, often spanning thousands of kilometers. UHV AC lines offer lower power loss due to reduced current flow because electricity is transmitted at a higher voltage. However, UHV AC lines require advanced insulation technology and specialized equipment to effectively handle higher voltages. On the other hand, HVDC lines are used for long-distance transmission when the distance exceeds a certain threshold, usually around 600 to 800 km. When the transmission is carried out at higher voltages, the volume of the conductor material is required, the voltage drops, and the losses are reduced. This makes it economical to transmit large amounts of power over long distances [35].

HVDC technology converts the alternating current to the direct current at the transmitter end and converts it back to the alternating current at the receiving end [37]. HVDC transmission has advantages in long-distance transmission, such as reduced power loss and the ability to control current. It is also suitable for underground and underground cable transmission. HVDC is the only feasible method to achieve the following objectives: connecting two networks that operate at different speeds, addressing environmental issues, decreasing electrical currents during faults, utilizing long underground cable routes, avoiding network congestion, and sharing utility rights-of-way without compromising reliability [37]. HVDC effectively complements the AC transmission technology in all of these situations. These devices offer enhanced operational flexibility in the electrical grid while circumventing the environmental and right-of-way limitations that are linked to traditional solutions [38].

The choice between EHV/UHV AC and HVDC transmission depends on several factors, including transmission distance, cost considerations, environmental factors, grid stability, and the specific requirements of the electrical system. Transmission planners carefully evaluate these factors to determine the most appropriate transmission technology for each project. Overhead transmission lines (OHTL) and underground transmission cables (UGTC) are the two types of AC power transmission lines. The bulk of AC power transmission systems are overhead lines because underground cable systems are substantially more expensive than overhead lines. OHTL is frequently utilized for long-distance power transmission in open counties and rural regions [39]. Furthermore, OHTL has a longer lifespan, is simpler to install and maintain and has cheaper manufacturing and construction costs than UGTC. Figure 2 depicts the structural difference, and Table 3 illustrates the fundamental difference between the HVAC and the HVDC transmission system. The use of HVDC technology increases current density in overhead transmission lines. This necessitates the use of high-temperature, low-sag conductors and high surge impedance loading. HVAC to HVDC conversion devices such as voltage source converters, modular multilevel converters and switched conductor schemes are utilized to improve transmission capacity and to reduce line losses [39]. OHTL has an earth wire to protect the transmission lines from lightning.

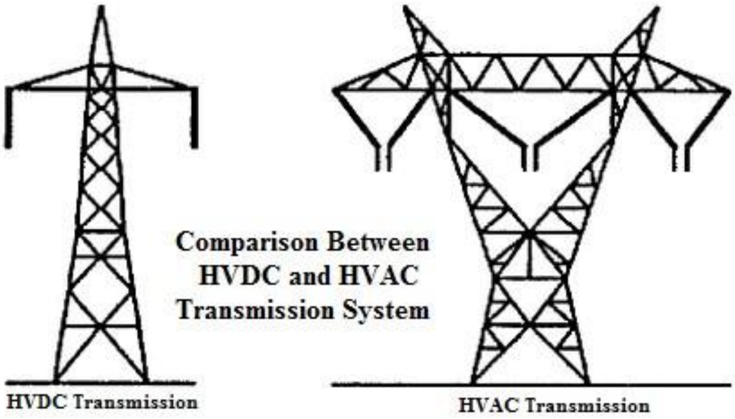
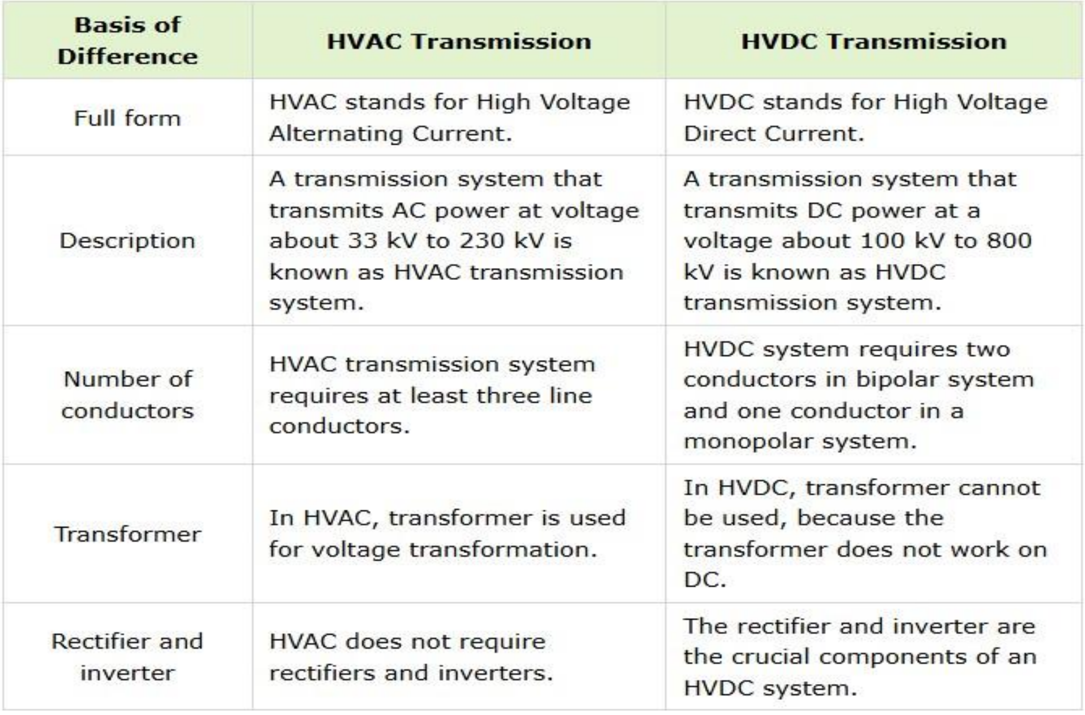
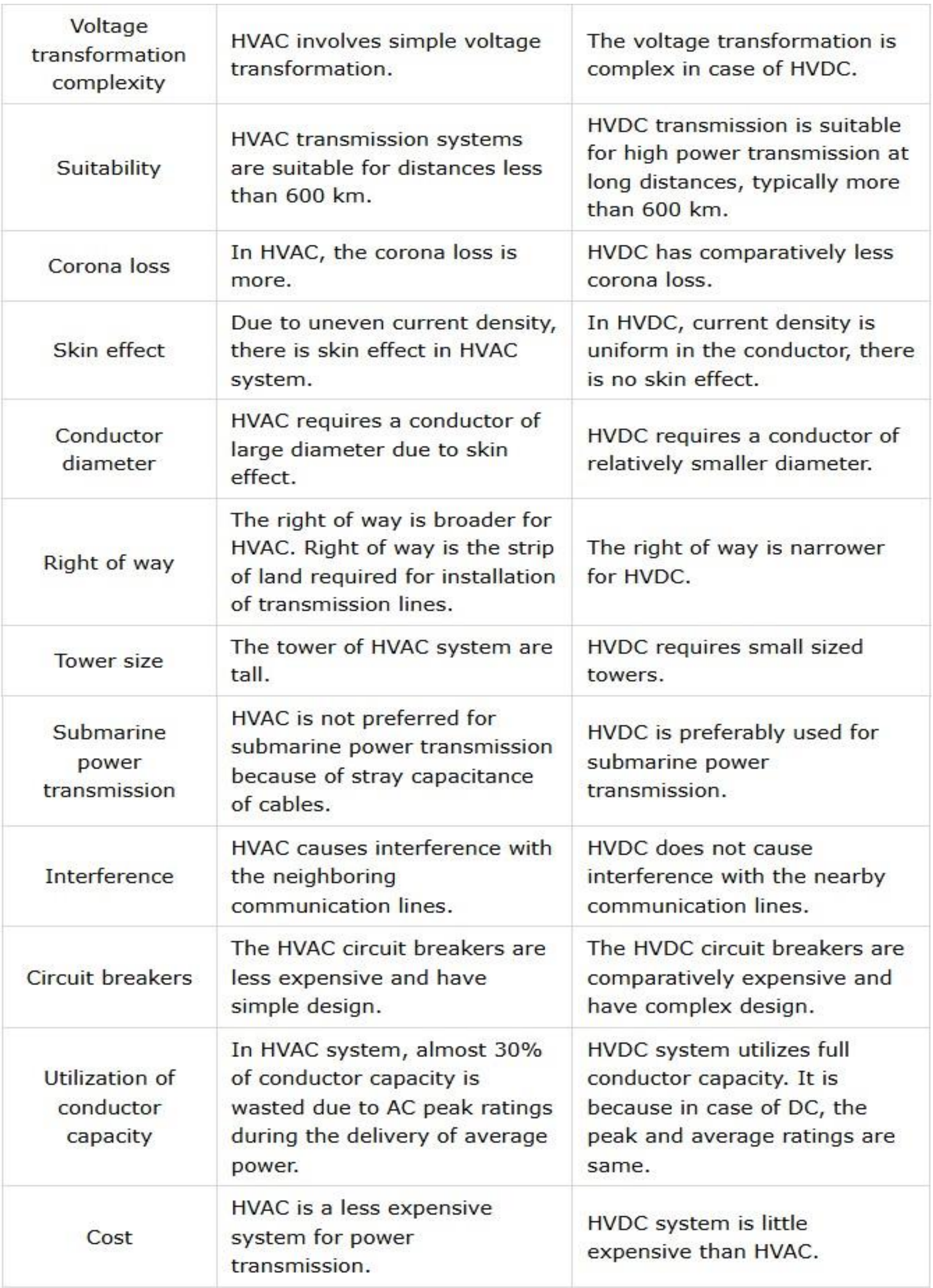


Figure 2: Comparison between HVDC and HVAC transmission systems [40].

Table 3: Basic differences between HVAC and HVDC transmission system [41].



Basis of Difference	HVAC Transmission	HVDC Transmission
Full form	HVAC stands for High Voltage Alternating Current.	HVDC stands for High Voltage Direct Current.
Description	A transmission system that transmits AC power at voltage about 33 kV to 230 kV is known as HVAC transmission system.	A transmission system that transmits DC power at a voltage about 100 kV to 800 kV is known as HVDC transmission system.
Number of conductors	HVAC transmission system requires at least three line conductors.	HVDC system requires two conductors in bipolar system and one conductor in a monopolar system.
Transformer	In HVAC, transformer is used for voltage transformation.	In HVDC, transformer cannot be used, because the transformer does not work on DC.
Rectifier and inverter	HVAC does not require rectifiers and inverters.	The rectifier and inverter are the crucial components of an HVDC system.



Voltage transformation complexity	HVAC involves simple voltage transformation.	The voltage transformation is complex in case of HVDC.
Suitability	HVAC transmission systems are suitable for distances less than 600 km.	HVDC transmission is suitable for high power transmission at long distances, typically more than 600 km.
Corona loss	In HVAC, the corona loss is more.	HVDC has comparatively less corona loss.
Skin effect	Due to uneven current density, there is skin effect in HVAC system.	In HVDC, current density is uniform in the conductor, there is no skin effect.
Conductor diameter	HVAC requires a conductor of large diameter due to skin effect.	HVDC requires a conductor of relatively smaller diameter.
Right of way	The right of way is broader for HVAC. Right of way is the strip of land required for installation of transmission lines.	The right of way is narrower for HVDC.
Tower size	The tower of HVAC system are tall.	HVDC requires small sized towers.
Submarine power transmission	HVAC is not preferred for submarine power transmission because of stray capacitance of cables.	HVDC is preferably used for submarine power transmission.
Interference	HVAC causes interference with the neighboring communication lines.	HVDC does not cause interference with the nearby communication lines.
Circuit breakers	The HVAC circuit breakers are less expensive and have simple design.	The HVDC circuit breakers are comparatively expensive and have complex design.
Utilization of conductor capacity	In HVAC system, almost 30% of conductor capacity is wasted due to AC peak ratings during the delivery of average power.	HVDC system utilizes full conductor capacity. It is because in case of DC, the peak and average ratings are same.
Cost	HVAC is a less expensive system for power transmission.	HVDC system is little expensive than HVAC.

Overloading in AC transmission systems poses a complex problem. It can result in higher power losses, voltage drops and negative environmental impacts. These factors can weaken the stability of the power grid, obstruct the integration of affordable generation sources and impede the implementation of renewable energy technologies [42]. In the past, reducing congestion has involved building more transmission lines. However, this approach is often too expensive and faces significant environmental and right-of-way obstacles. In recent years, Flexible AC

Transmission System (FACTS) devices have emerged as a promising alternative. These devices provide greater operational flexibility within the power grid without facing the same environmental or right-of-way limitations as traditional solutions [39]. Nevertheless, the significant expenses linked to FACTS devices require a careful and detailed approach, as their deployment may not be universally suitable.

2.3.1 Transfer Limits Associated with Transmission Lines

The associated transfer limits are:

- **Thermal Limits -** They specify the maximum amount of electrical current that a transmission line can carry over a given period before it sustains permanent damage due to overheating. It happens when electrons collide in an alternating current (AC) power line, causing electrical resistance. When resistance interferes with the current, heat is produced.
- **Voltage Limits -** The system voltages and voltage changes must be kept within an acceptable range for both the minimum and maximum limits. Voltage constraints in the AC transmission system inevitably need consideration for both real and reactive power loads and transfers.
- **Stability Limits -** A phase angle is the amount by which the generating voltage is ahead; above 90 degrees, power flow decreases and becomes entirely unstable. The transmission network must be able to withstand disruptions during transient and dynamic periods. Small-signal stability refers to the system's capacity to maintain synchronism in the presence of minor disturbances, whereas transient stability refers to disturbances.

2.3.2 Modelling of Transmission Lines

The objective of a transmission line is to efficiently transfer electricity across a distance while minimizing voltage fluctuations. Transmission lines can be modelled using an equivalent circuit that includes circuit characteristics specific to each phase. The terminal voltages are expressed in line-to-neutral form, whereas the currents are expressed as phase currents. The transmission line models are classified based on their lengths and the voltage they carry. These models include the short line (80 km), medium line (80-250 km), and long line (more than 250 km) types [43]. For this study, only the short-line model and medium-line model will be considered since Lesotho’s transmission network has 132 kV as the highest voltage of the transmission line. All transmission line models can be described as two-port networks. ABCD two-port network is the most commonly used representation with four constraints: A, B, C, and D, which are derived from the parameters. A transmission line can be easily represented by a two-port network, as illustrated in Figure 3.

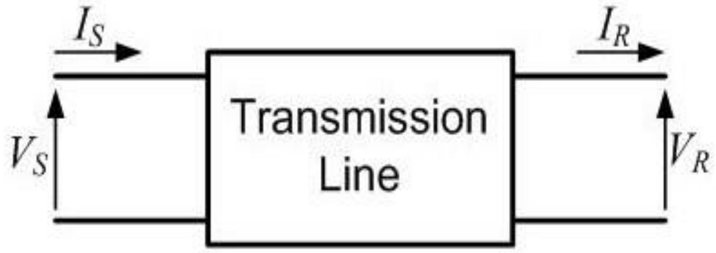


Figure 3: Two-port network representation [43].

Equation (1) shows the relationship between the quantities at the sending end and the receiving end:

Circuit equations: $$\{V^S = AV_R + BI_R \quad (1)$$
$$I_S = CV_R + DI_R$$

$$V^s \quad A \quad B \quad V_R$$
Matrix Form: $[\ ] = [\ ]\ [\ ]\ I_s\ C\ D\ I_R$

Where, V_S = Sending-end Voltage I_S = Sending-end current, I_R = Receiving-end Current, V_R =Receiving-end Voltage.

Voltage regulation refers to the percentage change in voltage at the receiving end of a transmission line when the load goes from no load to a given full load at a specific power factor while keeping the sending-end voltage constant. The percentage voltage regulation is determined by comparing the magnitude of the receiving-end voltage under no-load conditions to the magnitude of the receiving-end voltage under full-load conditions. The expression can be represented by Equation (2).

$$\text{Percent VR} = \frac{|V^{R(NL)}|-|V^{R(FL)}|}{|V_{R(FL)}|} \times 100 \quad (2)$$

In General, the no-load Voltage is V_s, $I_{R(NL)} = 0$, hence $V_{R(NL)} = {}^{V}{}_{A}{}^{\underline{s}}$

Where, $V_{R(NL)}$ = Voltage regulation for no-load, $V_{R(FL)}$ = Voltage regulation for full load, and A= Cross-sectional area of the line.

2.3.2.1 Short Line Model

The short transmission line model is used when the length of the line is less than 80 km and is suitable for the voltage level up to 69 kV. Due to the smaller length and lower voltage, the capacity of the line can be ignored, but the line is modelled using the resistance R and inductive reactance X. Figure 4 shows the circuit analysis of the short line model. The shunt admittance is not taken into account. The circuit is applicable to both single-phase and fully transposed three-phase lines that operate under balanced conditions. The short line model is calculated using Equation (3):

$$\begin{Bmatrix} I_S = I_R \\ V_S = V_R + (R + jwL)I_R = V_R + ZI_R \end{Bmatrix} \qquad (3)$$

Therefore, the matrix representation of a short-line model is: $\begin{bmatrix} V_s \\ I_s \end{bmatrix} = \begin{bmatrix} 1 & Z_{line} \\ 0 & 1 \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix}$ such that

A=D=1, B=Z_{line} and C=0. $Z_{line} = R + jL\omega$ Which is the impedance per unit length.

Z represents the impedance of each phase of the short line, L represents the inductance per unit length of each phase, R represents the resistance per phase of the line, and X represents the inductive reactance per phase of the line.

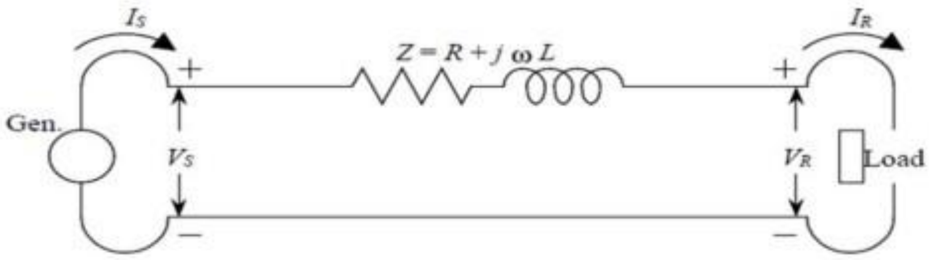


Figure 4: Circuit analysis of the short-line model [43].

2.3.2.2 Medium Line Model

The medium transmission line model applies to lines ranging from 80km to 250km in length. The model is utilized at transmission voltages over 69 kV when the inclusion of shunt capacitance is necessary to account for the elevated line charging current. The shunt capacitance can be divided equally and treated as concentrated at both ends of the line, following the nominal π-model. The line's resistance R and inductive reactance X are still taken into account. Figure 5 depicts the circuit analysis of the medium line model, in which half of the shunt capacitance is assumed to be concentrated at either end of the line. The medium line circuit equations (4a, 4b, 4c) are:

$$Y_C = (g + jwC)l \qquad (4a)$$

$$V_S = V_R + Z_{line}\,(I_R + Y2\underline{C}V_R) = (1 + {}^{Z_{\underline{line}}2\;Y_c})V_R + Z_{line}I_R \qquad (4b)$$

$$I_S = (I_R + Y2\underline{C}\,V_R) + Y2\underline{C}\,V_S = Y_C\,(1 + Z_{\underline{line}}4\;Y_{\underline{C}})\;V_R + (1 + Z_{\underline{line}}2\;Y_{\underline{C}})\;I_R \qquad (4c)$$

Matrix representation: $[^{V}I_s{}^{s}] = [Y_C1(1{+}{+}Z_{\underline{line}}Z_{\underline{line}}{}^{2}\,4Y_{\underline{c}}Y_{\underline{C}})1 + Z^{line}Z_{\underline{line}}2\;Y_{\underline{C}}]\;[^{V}I_R{}^{R}]$ Such that

ABCD values are: $= 1 + Z_{\underline{line}}2\;Y_{\underline{c}}$, $B = Z_{line}$, $C = Y_C\,(1 + Z_{\underline{line}}4\;Y_{\underline{C}})$, $D = 1 + Z_{\underline{line}}2\;Y_{\underline{C}}$

Where Y_C = total shunt admittance of the line, g = shunt conductance per unit length, C = lineto-neutral capacitance per unit length, l = length of the line, Z_{line} = total series impedance of the line.

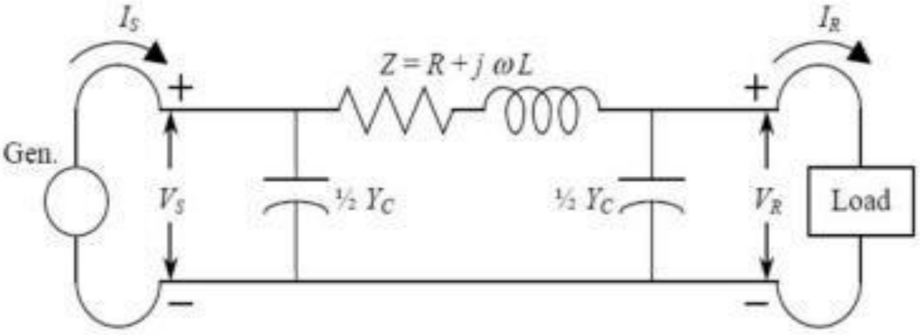


Figure 5: Circuit analysis of the medium line model [43].

2.3.2.3 Conductor Material in Transmission Lines

The conductors carry electricity from the sending end station to the receiving end station. The most commonly used conductor materials in overhead lines are aluminium and its alloy. Copper conductors are mostly used in distribution systems because of their high currentcarrying capacity and durability. A single circuit line uses three conductors, whereas a double circuit line uses six conductors. Equation (5a, 5b, and 5c) represents the resistance for DC, AC, and temperature dependence resistance, respectively:

Line resistance (R):

DC resistance: $R_{DC} = \rho\ {}_{A}{}^{l}$ (5a)

Where ρ = conductor resistivity, l = length of the lime and A = conductor cross-sectional area

AC resistance: $R_{AC} = 1.02R_{DC}$ (5b)

Temperature dependence: $R_{new} = R_{old}\,\frac{T+t_{new}}{T+t_{old}}$ (5c)

2.3.2.4 Line Supports for Transmission Lines

Figure 6 shows the line supports for electrical transfer. They consist of poles or towers that provide support to conductors so that the conductors are at a suitable level above the ground, maintaining the proper spacing between them in order to avoid short circuits [44]. They also maintain ground clearance in order to avoid short circuits between the conductor and the ground. The cost of the structure typically represents 30% to 40% of the overall expenditure for a transmission line. Hence, the selection of an optimal structure is crucial for designing a transmission line that is cost-effective [44].

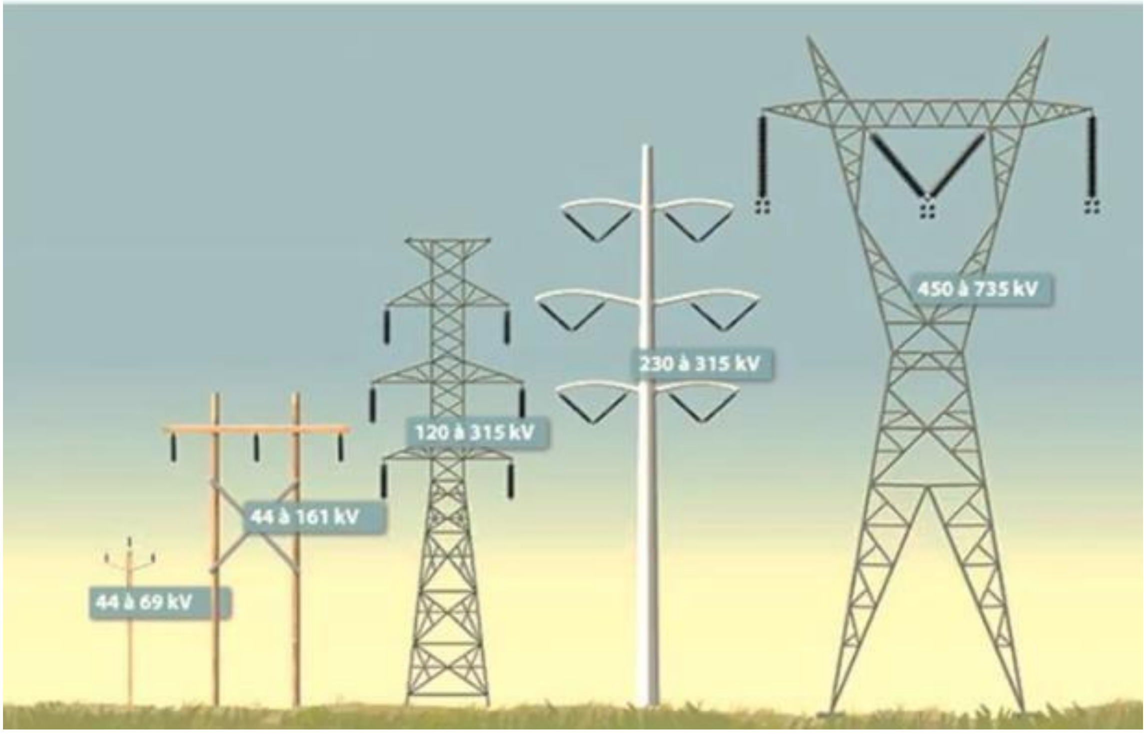


Figure 6: Line supports for transmission [44].

2.3.2.5 Line Insulators

Line insulators are employed to provide mechanical support to the line conductors and electrically separate them from the earth. Additionally, they are employed to electrically isolate line conductors from one another and from the supporting structures. The most commonly used material for overhead transmission lines is porcelain. However, there are several types of insulators used in transmission lines, including pin type, suspension type, strain, and shackle insulators [44].

2.4 Transformers in Power Systems

Power transformers have extensive applications in AC electrical systems, serving a crucial function in the transmission, distribution, and utilization of electricity. These stationary devices utilize electromagnetic induction to transmit electrical energy between circuits, modifying voltage and current levels while keeping the frequency constant [45]. The fundamental operation is based on the utilization of a magnetic core and a minimum of two windings, enabling the transmission of energy between coils without the need for a direct electrical link. Transformers are essential components of many transducers due to their ability to reduce Joule losses and facilitate efficient power transmission [45]. Furthermore, transformers give galvanic isolation between circuits, which provides a safety advantage in the power system.

Transformers are essential in the field of power transmission. Significantly, they are widely used in applications involving the transmission of power across great distances. Transformers effectively minimize power losses during transmission by selectively boosting voltage and decreasing current levels while maintaining optimal power delivery. Moreover, the fundamental ideas that form the basis of transformers have been crucial in the advancement of various contemporary sensors such that they always maintain proper power quality [42]. Each transformer possesses a unique temperature increase capacity, which is utilized to determine its nameplate rating, either 55°C or 65°C [42]. These temperature increases represent the average rise in temperature of the winding of a transformer over the surrounding environment. This rise can occur continuously without affecting the expected lifespan of the transformer. Power transformer emergency circuit ratings must not fall below 100% of their maximum nameplate rating.

2.5 Capacity Expansion Planning (CEP)

Traditionally, utilities have employed capacity expansion models to optimize their future power generation to meet demand efficiently while minimizing both capital and operational costs [3]. These models are focused primarily on the generation side. However, as power systems grow in complexity, there is a growing recognition of the need to integrate generation and transmission planning. In this integrated approach, planners aim to optimize expansion decisions holistically, considering the interdependencies between generation and transmission and their associated costs. While this integrated approach has clear benefits, it poses challenges related to data management, departmental coordination, regulatory compliance, and uncertainties in factors like load growth and technological advancements [3]. Capacity expansion planning consists of two main facets, GEP and TEP, as mentioned earlier. GEP is mainly focused on producing the power that will be able to satisfy the forecasted load within the given reliability criteria for a period of about 10 to 30 years [34]. The goal of GEP is to extend the existing power system by building additional plants while taking into account size, technology, location, and expected time to meet future demand while meeting reliability standards [34]. However, the generation of electricity requires capitally intensive investment concerning the feasibility studies, risks, and uncertainties, as well as the installations.

Electric TEP is a complex problem that strives to specify the addition of transmission facilities that offer enough capacity while retaining the operational performance of the electric transmission system [46]. However, because the problem is complicated, large-scale, challenging, and nonlinear, TEP represents a significant barrier in power system optimization. Transmission planning can be managed through analytical tools and requires the ability to perform economic and technical evaluations [47]. TEP's mixed-integer nature leads to an exponentially increased number of viable solutions as the system size is enlarged. Researchers have suggested a variety of optimization strategies to handle the TEP issue, including mixedinteger linear programming (MILP), robust optimization, adaptive multi-operator evolutionary algorithms, composite teaching learning-based optimization algorithms, and ant colony optimization [26, 27]. The algorithm of choice is determined by the problem's unique needs as well as the features of the power system. TEP is mainly focused on transporting the power from the generation plants to the substations or load centers. TEP also determines when and where the existing transmission lines need to be reinforced [35].

GEP and TEP models have lately been used to accommodate reliability targets, environmental concerns, and renewable energy (RE) plants [50]. According to Hemidpour [51], generation and transmission expansion plans have separate economic, operational, and reliability indices, and enhancing one index does not always enhance the other. Thus, it is required to model indices simultaneously to achieve optimal power system performance. According to Hemmati [34], both the TEP and GEP models are mathematically based on large-scale, extremely constrained mixed-integer non-linear programming. This framework is made up of two main components: limitations (or constraints) and an objective function. Among other things, the objective function addresses costs associated with new technologies, power line extension, increasing reliability, and the power market. Constraints, on the other hand, are classified into two types: mandatory and optional. Both sorts of limitations, whether essential or optional, must be carefully examined while planning. Examples of mandatory limits include transmission line capacity limitations and the need to fulfill specified load and reliability criteria. Optional constraints, on the other hand, serve to enhance flexibility in the planning process.

2.5.1 Optimization Strategies for TEP Problem

Researchers conducted TEP literature studies to fully grasp the problem and discover the best methods for addressing it. TEP is often approached using optimization techniques that can handle the nonlinear and non-convex nature of the problem. Many optimization strategies have been presented throughout the years to handle the problem of TEP in dispatched power networks. The results obtained in TEP models help minimize transmission saturation or network congestion. However, its implementation is constrained by economic, environmental, social, and operational factors that could hinder or prolong transmission line construction [52]. These methods are broadly characterized as mathematical and heuristic optimization approaches [49]. Some common optimization techniques used in TEP are:

2.5.1.1 Mixed-Integer Linear Programming (MILP)

The MILP technique is widely used in TEP and takes into account losses, generator costs, and the N-1 security restrictions for multi-stage security-constrained transmission expansion planning [53]. It is adaptable enough to create new networks as well as strengthen existing ones. The model's mathematical formulation is based on the tactics of transmission network actors to maximize their advantages, as well as the practical constraints on energy flow in the transmission network. The TEP model with MILP provides a dynamic technique for estimating transmission line investments across various periods, investment payback periods, yearly depreciation rates, and supply and demand increases [52]. Furthermore, it transfers the anticipated start date, operational and investment expenses allotted to each year. This entails tracking the evolution of node costs and transmission saturation as the system expands.

2.5.1.2 Heuristic Method

Heuristic models generate, compare, and select optimal plans step by step until no better option is found. They have been applied to TEP problems, such as differential evolution, constructive heuristic algorithm, particle swarm optimization, genetic algorithm, chaos optimal algorithm, and simulated annealing [6]. They are simple to use, don't require power system model conversion, and can fall into local minima. They are easier to modify and conduct power system analysis. If a new constraint is added, heuristic models are easier to alter without significant rearrangement, and heuristic models may be used for further power system analysis, such as transient stability analysis [54].

2.6 Economic Voltage of Transmission Lines

Economic transmission line voltage calculations consider factors like load analysis, transmission distance, capital and operating costs, efficiency, losses, voltage stability, and regulatory constraints. The goal is to find the optimal voltage level for efficient power transmission, balancing initial capital investment and long-term operational efficiency [5]. The economic voltage refers to the optimal voltage level at which the expenses associated with conductor material, transformers, switchgear, and other equipment are minimized. Figure 7 depicts the link between investment cost (Y) and transmission voltage level (X), with point Z being the lowest point and voltage at OX representing the ideal transmission voltage.

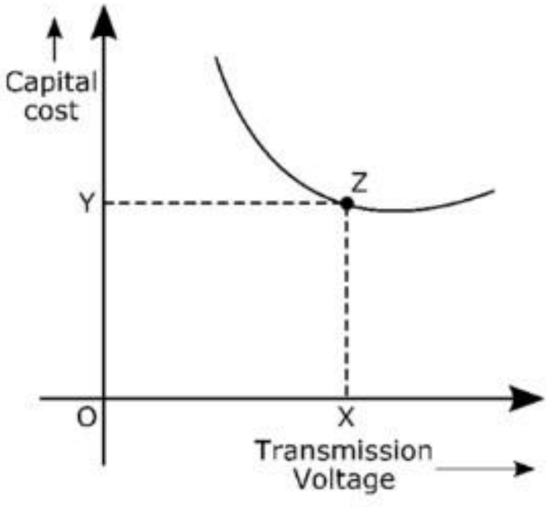


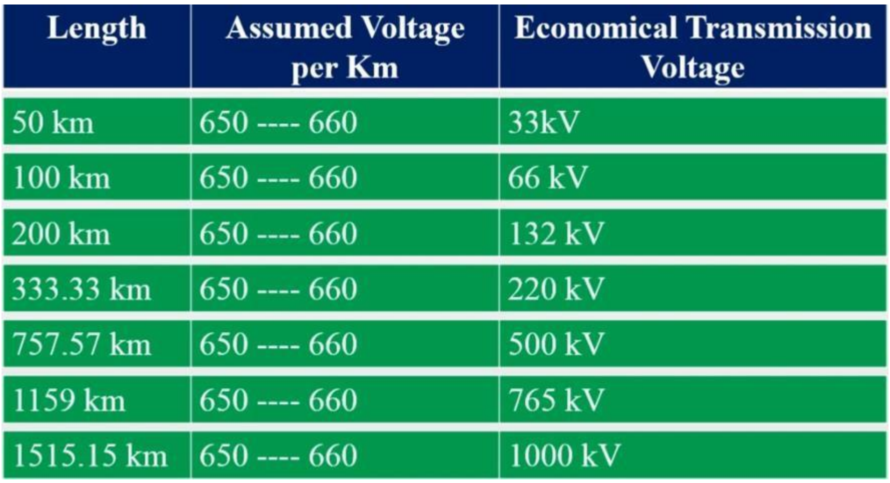
Figure 7: Economic relationship between voltage and transmission lines [5].

The economic strain of transmission lines is often difficult to determine due to equipment costs. Equation 6 employs an empirical formula to determine the optimal voltage for transmitting power in a three-phase AC system.

$$V = 5.5\sqrt{0.62L + \frac{P}{150}} \qquad (6)$$

The voltage (V in kV) of a cost-effective transmission line is defined by the length (L in km) of the line and the power transferred (P in kW). Table 4 shows the considered economic voltages based on the length of the transmission line.

Table 4: Economic voltage transmission and their required lengths [55].



Length	Assumed Voltage per Km	Economical Transmission Voltage
50 km	650 ---- 660	33kV
100 km	650 ---- 660	66 kV
200 km	650 ---- 660	132 kV
333.33 km	650 ---- 660	220 kV
757.57 km	650 ---- 660	500 kV
1159 km	650 ---- 660	765 kV
1515.15 km	650 ---- 660	1000 kV

2.7 Transmission Network Stability Analysis

2.7.1 N-1 Contingency

N-1 contingency is a critical concept in power system design and operation, providing grid dependability in the event of a transmission component breakdown [35]. This backup plan seeks to keep the power supply constant even if a single component fails. It entails a series of events, such as the first loss of a transmission component, system changes, and subsequent failures that ensure the system can endure the unexpected failure.

2.7.2 Short-circuit Calculations

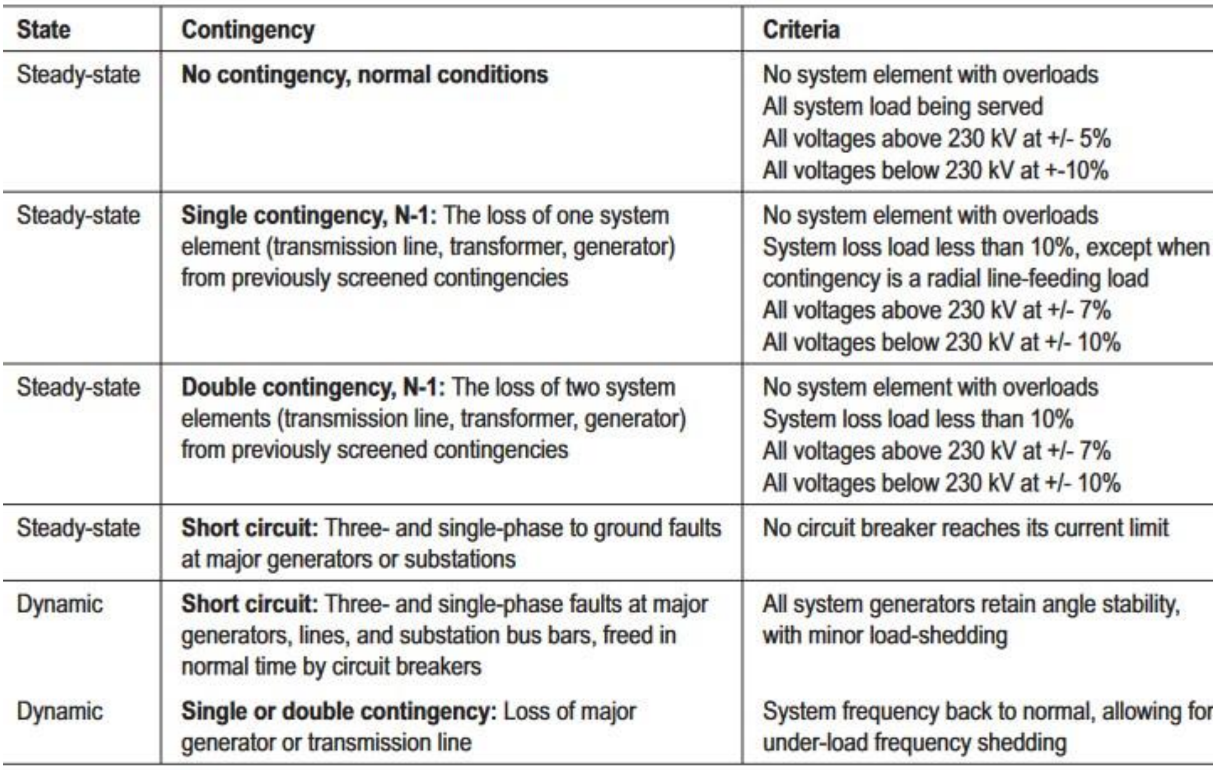
Short-circuit calculations for transmission lines include computing short-circuit currents for protective device coordination and analyzing the impact of failures on the power system. Data collection, per-unit system conversion, fault detection, pre-fault and post-fault condition analysis, symmetrical components, short-circuit current calculations, and equipment rating verification are all part of the procedure. This analysis is critical for constructing protective devices and guaranteeing the power system's safety and dependability [56], [57].

2.8 Power Reliability

Power outages, which are frequently caused by component failures in the distribution system, are a constant source of worry for both utilities and end consumers. The distribution system, which serves as the final connection between energy generation and end customers, is critical to guaranteeing a reliable and uninterrupted supply of power [58]. Improving distribution network reliability is crucial for reducing power outages and increasing customer satisfaction. There are several approaches to improving distribution network reliability. They include the use of faster failure prediction techniques, fewer unexpected equipment breakdowns and the installation of reliable protective mechanisms [58], [59]. Reclosing machinery, switching equipment and automation are examples of high-tech items. End-user satisfaction is impacted by power outages and the inadequate reliability of the power supply. Table 5 shows the reliability criteria commonly used in power systems to sustain a reliable power network. There are two kinds of reliability; steady-state reliability and dynamic-state reliability. Steady-state refers to the system functioning at the moment, in time under operating conditions, like taking a snapshot of the system after its dynamic behavior has settled. On the other hand, dynamic state refers to the behavior of the system after experiencing changes in system settings, power generation or load, which typically last from milliseconds to seconds until the system reaches a condition. A stable condition is achieved when the network voltage and frequency reach their working values without any changes over time and with little to no load shedding.

The N-1 criterion is one of the most well-known criteria for steady-state dependability. This implies that even if a single network piece fails, the electrical transmission network must be able to provide all power from generation to demand. For example, if a big electrical substation is erected in a city, the substation may be powered by two distinct transmission lines, so that if one line breaks, the city is not left without electricity. That would be preferable. In certain systems, such reliability criteria extend to N-2 failures [60]. This means that the transmission system must be able to sustain the whole load even if two network nodes fail. To determine whether a proposed gearbox design fits such criteria, a steady state or power flow models are used. After the loss or failure of an element within the system, dynamic state reliability standards generally ensure that the system voltage and frequency fluctuations shift to a steady state with low load losses. The dynamic behavior of a system is determined by the severity of changes within the system, when and where the changes occur within the system and how the system loads, transmission, generation, control, and protection interact [58]. Certain dynamic characteristics of the system are more dependent on the transmission system than others. Contingency analysis involves examining the impact of the failure of a transmission or generating components, such as transformers, lines and generators, on the loading of the remaining system and the amount of bus voltage [61]. This analysis is crucial to understanding the impact of element outages on the power system security during operation and planning. Contingencies have the potential to cause significant breaches of the operating limits. Hence, incorporating provisions for unforeseen circumstances is a crucial aspect of ensuring the safe and efficient functioning of the power system.

Table 5: Widely used reliability criteria for power systems [62].



State	Contingency	Criteria
Steady-state	**No contingency, normal conditions**	No system element with overloads All system load being served All voltages above 230 kV at +/- 5% All voltages below 230 kV at +-10%
Steady-state	**Single contingency, N-1:** The loss of one system element (transmission line, transformer, generator) from previously screened contingencies	No system element with overloads System loss load less than 10%, except when contingency is a radial line-feeding load All voltages above 230 kV at +/- 7% All voltages below 230 kV at +/- 10%
Steady-state	**Double contingency, N-1:** The loss of two system elements (transmission line, transformer, generator) from previously screened contingencies	No system element with overloads System loss load less than 10% All voltages above 230 kV at +/- 7% All voltages below 230 kV at +/- 10%
Steady-state	**Short circuit:** Three- and single-phase to ground faults at major generators or substations	No circuit breaker reaches its current limit
Dynamic	**Short circuit:** Three- and single-phase faults at major generators, lines, and substation bus bars, freed in normal time by circuit breakers	All system generators retain angle stability, with minor load-shedding
Dynamic	**Single or double contingency:** Loss of major generator or transmission line	System frequency back to normal, allowing for under-load frequency shedding

Furthermore, there are trade-offs between the principles that are commonly followed in transmission design, particularly in terms of cost and dependability [62]. More dependable networks are more expensive since they require more investment to achieve redundancy and more equipment to enable the network to manage numerous unforeseen occurrences without power interruption, as shown in Figure 8. While faulty networks are less expensive, they can cause large financial losses. To address these trade-offs, planning or regulatory bodies have usually imposed dependability criteria. To ensure that these tradeoffs are adequately addressed, transmission planners integrate the criteria into their planning approaches.

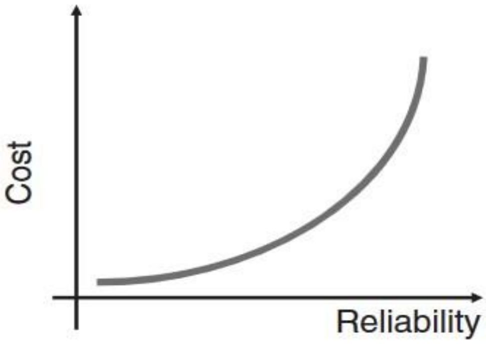


Figure 8: The cost and reliability trade-offs of the power system [62].

The assessment of power system dependability focuses on two major aspects: system security and system adequacy. The capacity of a system to adapt to disruptions such as local and regional disturbances and the unexpected loss of vital facilities is referred to as security. In contrast, adequacy refers to the capacity of the system to fulfill consumer load demand or operating limits. Until the 1990s, reliability studies were based on analytical methodologies that were impacted by the size of the system state space [63]. For simulations of power systems with numerous operational states, the Monte Carlo simulation was later favoured. Generation adequacy is critical in determining supply security [63].

The usefulness of a typical energy system plan is assessed at two levels: the macro and micro levels. The macro stage examines the plan from a strategic policy standpoint, including an assessment of appropriateness, safety and dependability. However, at the micro level, the plan is evaluated from the standpoint of technical feasibility and it includes technical analyses such as error and stability analysis. When conventional energy systems are planned, reliability and validity evaluations come before stability and failure analyses. The most prevalent reliability measures, such as Load Loss Expectation (LOLE, expressed in hours), Expected Undelivered Energy (EENS), Load Loss Probability (LOLP), Load Loss Cost (LOLC), Loss of Energy Probability(LOEP), are used to assess system dependability [11], [63]. These reliability indices are simulated using Monte Carlo simulation since the indices of reliability represent the capability of the generating plants to respond to the demand of the system [63]. They help to find a reliable energy supply during peak and high demand times

2.8.1 Reliability Indices

The loss of load happens mostly when the system load exceeds the generating capacity available for use. The LOLP is the probability of the system load exceeding the available generating capacity since in the long run, the load on a power system is expected to be greater than the capacity of the available generating capacity [64]. All the probabilistic matrices of reliability are derived from the LOLP since it is the most extensively employed probabilistic criterion in generation capacity planning. It is best to have the amount of the accumulated shortage time being less than 0.0274% of a day which is less than 1 day in 10 years [63]. LOLP can be evaluated using Equation 7 as:

$$\mathrm{LOLP} = \sum_{j=1}^{G} G_j \times P\left(L > G_j\right) = \sum_{j=1}^{G} \frac{G^j + t^j}{100} \qquad (7)$$

Where t_j = is the percentage of time where the load is greater than the generation capacity G_j.

LOLE is the probable number of hours in a year where the total available capacity is lower than the system load [64]. In real situations, the LOLE is more frequently used than LOLP and they are connected using Equation (8).

$$\mathrm{LOLE} = \mathrm{LOLP} \times 8760\mathrm{h} \qquad (8)$$

LOEP is the ratio of EENS and total power demand (E). It is also used to evaluate the power generation reliability during yearly observations. It can be calculated using Equation (9).

$$\mathrm{LOEP} = \sum{}^{G}{}_{k=1}{}^{E\underline{k}\times}{}_{E}{}^{p\underline{k}} \qquad (9)$$

Where E is the early total energy demand (MWh), E_k = the energy not supplied due to capacity outage, p_k = the probability of the capacity outage.

2.9 Economic Analysis of Transmission Lines

Economic analysis of transmission lines and related infrastructure is an essential aspect of energy planning and development. These components are fundamental to the operation of the grid. The economic considerations related to their design, construction and operation have farreaching impacts [43, 44]. Economists and energy experts use a variety of tools and models to evaluate the profitability and benefits of transmission lines. Modeling tools such as EPRI US REGEN, EnCompasV6.2, CGT-Plan (EMPS), Aurora v14.2, etc. [3], [67] are mostly used in generation, transmission and storage for bulk systems. However, the transmission investments are represented using sensitivity cases that are not selected by the models. Some of the tools (Aurora v14.2, EnCompass v6.2) are used for fossil fuel-based generations with limited bidirectional limits. The primary goal is to balance the required initial investment with long-term economic benefits, including increased reliability and access to diverse energy sources. The DIgSILENT PowerFactory model can simulate the investment costs from the generation, transmission, and distribution; it also includes an 8760-hour end-use demand module which is run in an iteration with the energy production [68], [69], [70]. According to the U.S. Department of Energy study "The Value of Transportation in the Electric Power System," a well-designed and efficiently operated transportation system can provide significant economic benefits such as cost savings, reduced congestion and improved network resilience, all of which contribute to a reliable power system [71].

2.10 DIgSILENT PowerFactory

To create, simulate and evaluate networks of electrical systems from the point of generation to the point of transmission and distribution, the power industry uses a software package called PowerFactory [72]. PowerFactory is a valuable software application that supports the design, analysis and optimization of production and transmission line systems for power engineers and system planners. It offers various analysis functions, including load current, short circuit, semidynamic analysis, RMS/EMT simulation, economic analysis, grid tools, transmission and distribution network analysis [73]. The software is integrated with the DIgSILENT programming language (DPL) for automated simulations and can be accessed and run using Python scripts. It ensures the efficiency, stability and reliability of the power grid, contributing to effective grid management and expansion. It evaluates power system efficiency by calculating load flow for balanced and unbalanced systems using the AC Newton-Raphson technique and linear DC method [74]. The software includes tools for designing, analyzing, and simulating transmission lines to verify that electricity can be transported effectively over long distances while preserving voltage levels and system stability. With the growing integration of renewable energy sources, PowerFactory can simulate and assess the impact of variable resources such as wind and solar on the grid, assisting in the planning of their efficient integration.

2.11 Contribution of the Study

Currently, Lesotho generates electricity mainly from renewable energy sources such as hydroelectricity power and solar PV systems. However, the electricity generation is insufficient to meet the country’s demand for electricity without considering the imports. Lesotho has planned to supplement the hydropower plant and solar PV plant with wind generators as well as pumped storage generators so that the available resources (water, solar radiation and wind) are put to good use in generating electricity to have energy security while also battling global warming. These power generators will be integrated into the LEC network once they are implemented. The available network has the highest economical voltage of 132 kV, but previous methodologies imply that the studies conducted about TEP are mainly focused on networks that have voltages greater than 132 kV. The study will consider the LEC network as a test system for 132 kV voltages and solve the existing problem of integrating renewable energy generators into the system without causing transmission congestion or line loading.

In their previous research, Rateele and Thamae demonstrated a method of distributing power generated by local generators. They proposed the integration of a 50 MW Ha-Ramarothole solar PV, a 24 MW Masitise wind farm, a 34 MW Lets'eng wind farm, and a 72 MW ’Muela hydropower plant. This integration resulted in a significant reduction of grid imports by 59.7%. However, their study did not account for the impact of line loadings when dispatching power, nor did it address the situations where the available generation exceeds the demand, when the power is evacuated and when there is a need for exporting the power. Most of the studies from the previous years solved the TEP and GEP problems but did not consider the assessment of the economic viability of evacuating the power to load centers. This study considered the economic viability of evacuating the power from generation sources to transmission while also considering the power delivered by intermittent renewable energy sources. The proposed study will use the LEC's network to handle the load flows, considering the integration of renewable energy sources and imports into the grid, which can help other developing countries with economic voltages of 132 kV see the problems that they may encounter when trying to have supply security using RES.

3 Methodology

3.1 Overview

Evacuation of power from a generating plant considers various criteria which include investment cost, power flow analysis, load growth factors, land acquisition costs, and system reliability. The adopted methodology for this study considered five criteria presented in Figure 9 after performing the load flow analysis. The five criteria are economic voltage, N-1 criteria, component loadings, voltage stability, and contingency analysis. The process begins with finding the economic voltage, which is the best voltage level that balances investment costs with efficient power transfer. N-1 criterion ensures that the power grid remains stable and operational even if one critical component (such as a transmission line or transformer) fails. The component loadings are then assessed to minimize overloading, and voltage stability guarantees that voltage levels stay constant under varying load situations. Finally, contingency analysis investigates the system's resilience under various failure scenarios. If all of these criteria are met, the system configuration is deemed satisfactory for the reference year. The same analysis is then carried out for another reference year to account for load increase and other potential changes. If any requirements are breached during these simulations, solutions such as voltage upgrades or installing double transmission lines are explored to address the issues. If all the reference years meet the proposed methodology, the simulation could be stopped.

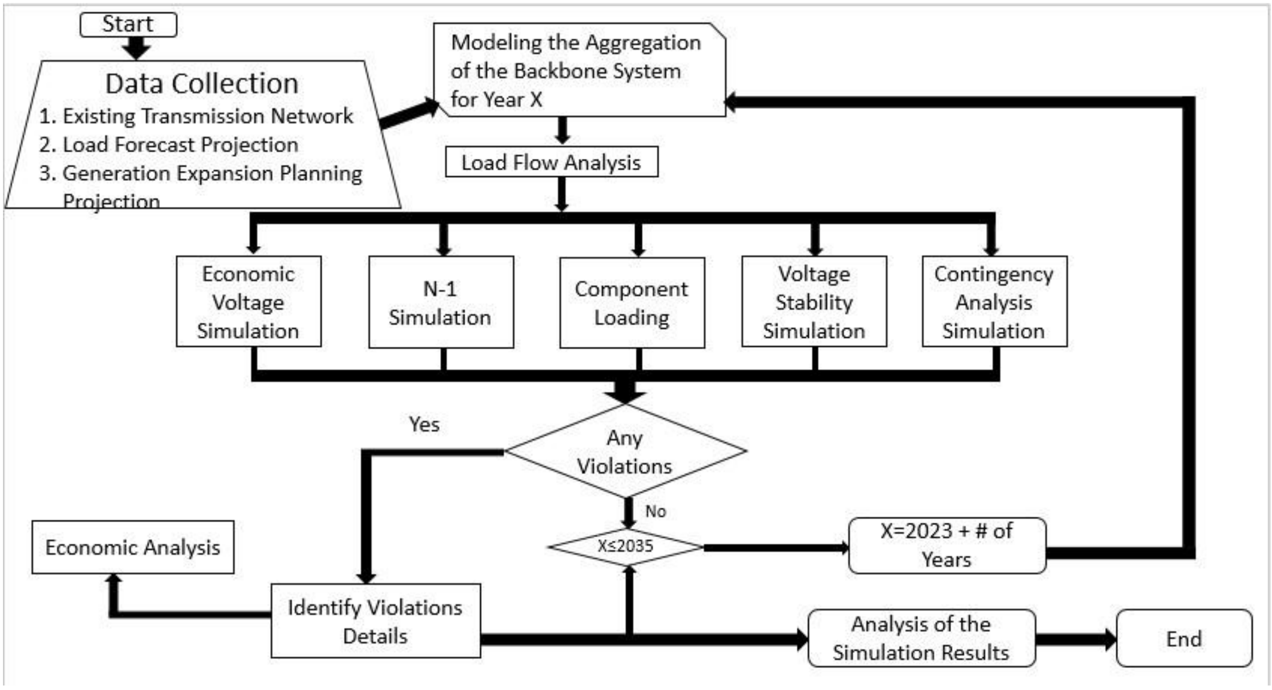
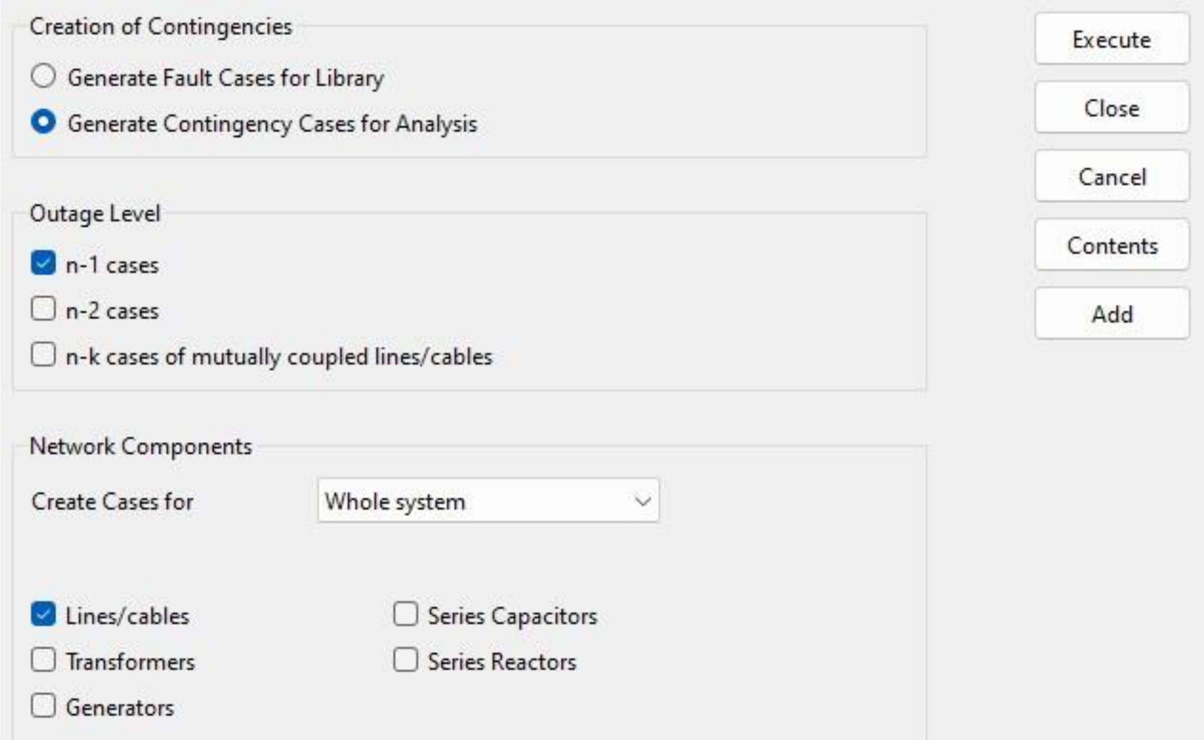


Figure 9: Methodological flowchart for transmission expansion planning.

To describe voltage changes in the network, N-1 contingency was considered. Figure 10 depicts the DIgSILENT Power Factory model, which was used to create N-1 contingency scenarios for the whole system to demonstrate voltage fluctuations.



Creation of Contingencies

○ Generate Fault Cases for Library
● Generate Contingency Cases for Analysis

Outage Level

☑ n-1 cases
☐ n-2 cases
☐ n-k cases of mutually coupled lines/cables

Network Components

Create Cases for: Whole system

☑ Lines/cables
☐ Transformers
☐ Generators
☐ Series Capacitors
☐ Series Reactors

Figure 10: Contingency criteria evaluation of LEC network.

The data to be used in this study was collected from LEC so that the network is upgraded to a good standard, with all the candidate lines projected for the base year (2023) included using

DIgSILENT software. The Ha Mofoka substation was used as a switching substation between the Ramarothole and Mazenod Tx substations that will offload the lines at the Ramarothole substation after adding 30 MW of solar PV to the grid. The load demand projections for the years 2023, 2030, and 2035 were considered for the study, and for each year, the proposed generation was included in the network and the simulations with different operation scenarios. The loads for 2030 and 2035 were adjusted to 36% and 54% respectively. These loads were made concerning the projected peak demand in those years. The load flow and stability simulations were conducted using the DIgSILENT PowerFactory program using the NewtonRaphson method. PowerFactory is a software program for computers specifically designed to analyse electrical transmission, distribution, and industrial networks. Furthermore, PowerFactory has the capability to simulate and examine electrical networks that incorporate changeable renewable energy producers.

3.2 Scenario Development

The network studies were conducted throughout the year, including peak and low demand periods. Three cases were considered: the base case (normal operating conditions), the emergency case (during issues or outages), and the development case (future upgrades or improvements). Each scenario was carefully researched to determine how the network would operate and the recommendations were made to ensure that everything ran well regardless of the circumstances. The following sixteen scenarios were analysed.

Base case: The base case scenario is conducted with two network tests for three reference years where the main generators of power are the ’Muela Hydropower with 72 MW, the Ramarothole solar PV with 30 MW and the imports from Eskom and EdM. In this operation scenario, the busbar voltage limits were set between 0.95 and 1.05 per unit (p.u). The loading elements limitations were set between 80 and 100%.

Emergency case: In this scenario, all the local generators are simulated as off-line to assess the network when the country only relies on imports from Eskom and EdM for three reference years. In this operation scenario, the busbar voltage limits were set between 0.9 and 1.1 p.u. The loading elements limitations were set between 80 and 100%.

Development case: In this scenario, only two reference years are considered. They are 2030 and 2035. All the power from the base case is included in 2030 with an additional 50 MW Ramarothole solar PV and 20 MW OnePower solar PV that will also be integrated at Ramarothole Substation. The 2035 scenario includes all generators from 2030, with additional

Hirundo wind farms with 39.6 MW at Mohale's Hoek and 26.4 MW at Masite Nek substations. In this operation scenario, the busbar voltage limits were set between 0.9 p.u and 1.1 p.u. The loading elements limitations were set between 80 and 100%.

3.3 Lesotho's Grid Code

The study utilized the Lesotho Electricity and Water Authority (LEWA) Grid code, which mandates system planners and operators to adhere to specific parameters in order to maintain system voltage stability. The key parameters include the voltage regulation and fault levels inside the network. The standard voltage restrictions in the network require that each transmission busbar must maintain a minimum allowed voltage of 0.95 p.u or 95% of the rated voltage. If the voltage decreases to 0.95 p.u., the transformer tap changers will often adjust the voltage at medium voltage levels (33 kV or 11 kV) to a level very close to unity or 100% of the rated voltage. The maximum acceptable voltage on any busbar must be 1.05 p.u. This is equivalent to 105% of the rated voltage. The emergency conditions for the network are when any busbar performs below a minimum allowable voltage of 0.9 p.u and above a maximum allowable voltage of 1.1 p.u [75].

3.3 LEC Network Topology

The LEC electrical grid consists of three power generation units: the 'Muela hydroelectric unit with a capacity of 72 MW, the Ramarothole Solar PV system with a capacity of 30 MW, and the Mants'onyane mini-hydro facility with a capacity of 2 MW. Moreover, the network is interconnected with South Africa's Eskom electricity grid. The transmission infrastructure comprises linked substations that operate at voltage levels of 132 kV, 88 kV, 66 kV, and 33 kV. On the other hand, the distribution network is constructed with voltage levels of 33 kV and 11 kV. The specified voltage levels for demand are 380 V and 240 V.

3.3.1 LEC Network Topology Inputs

Currently, the LEC network consists of generating stations, transmission systems, and distribution systems with different load centres. The power produced in Lesotho is only by RES, which is owned by IPPs. Therefore, the LEC buys the produced electricity from the IPPs after signing the Power Purchase Agreements (PPAs). Then, the LEC decides where the power should be evacuated, depending on their demand. The power is transferred from generation stations and the aim is to transfer the power most effectively and economically to minimise costs. The imports from South Africa and Mozambique use 132 kV transmission lines at Maseru intake (Eskom Infeed substation), but the power from Clarens is supplied through an 88 kV line to the Khukhune substation, while the power to Qacha's neck is supplied by Matatiele through a 22 kV line at the Letloepe substation.

Figure 11 represents the network layout of Lesotho with 58 substations which includes eighteen 132 kV lines, three 88 kV lines, six 66 kV lines, fifty-four 33 kV lines, and one 11 kV line utilized for distribution from Letloepe to Mpiti substation. Each substation consists of step-up or step-down transformers, with the minimum transformer capacity being 1.6 MVA and the maximum being 40 MVA. The reinforcement of the existing transmission systems should follow the same technical and operational standards as the LEC system. If it is necessary to build a new line that runs parallel to an existing line, it is preferable for the new line to have the same type of conductor as the existing line. This will guarantee a more streamlined operation and maintenance of the system.

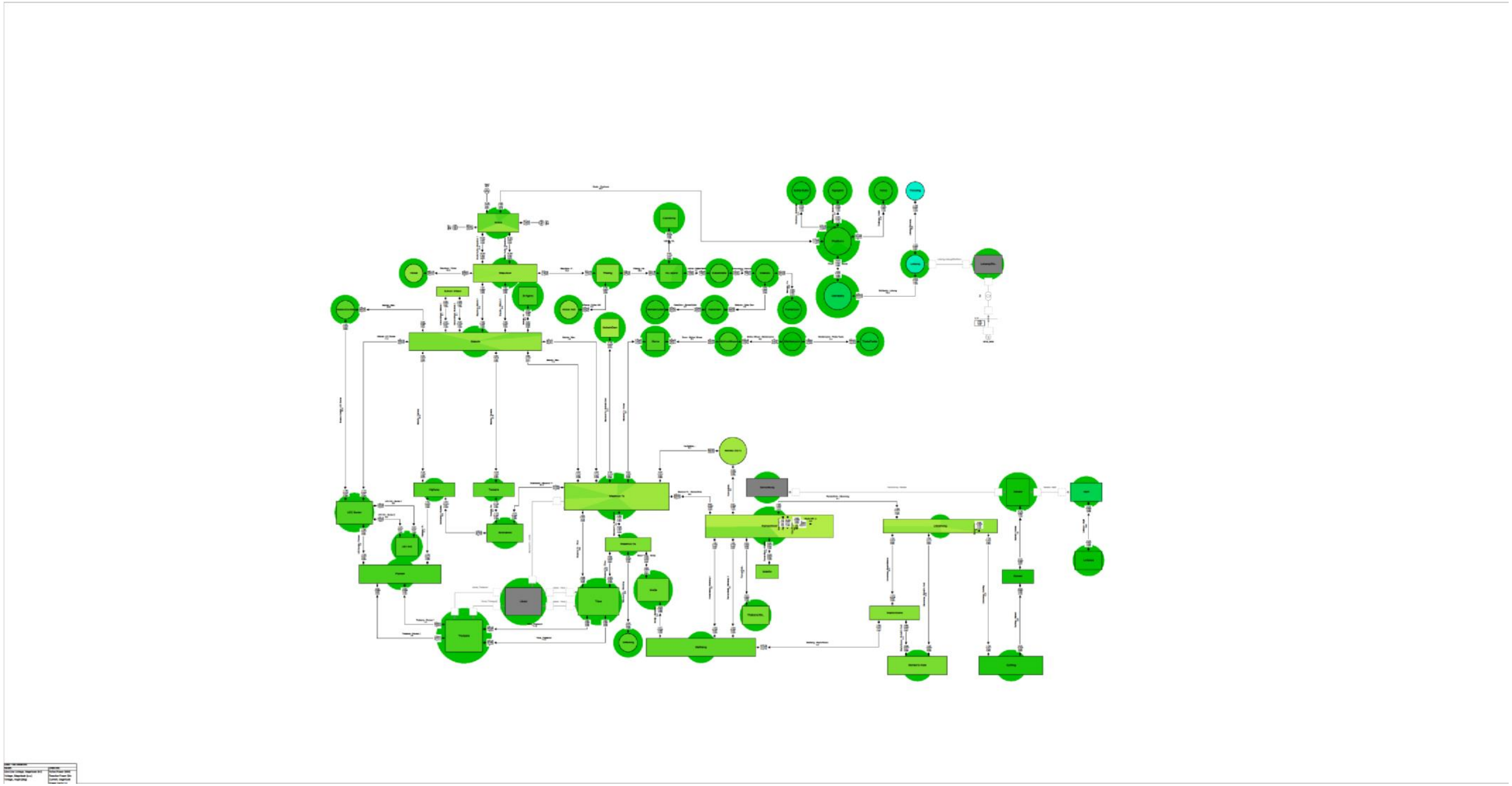


Figure 11: LEC network topology for 2023.

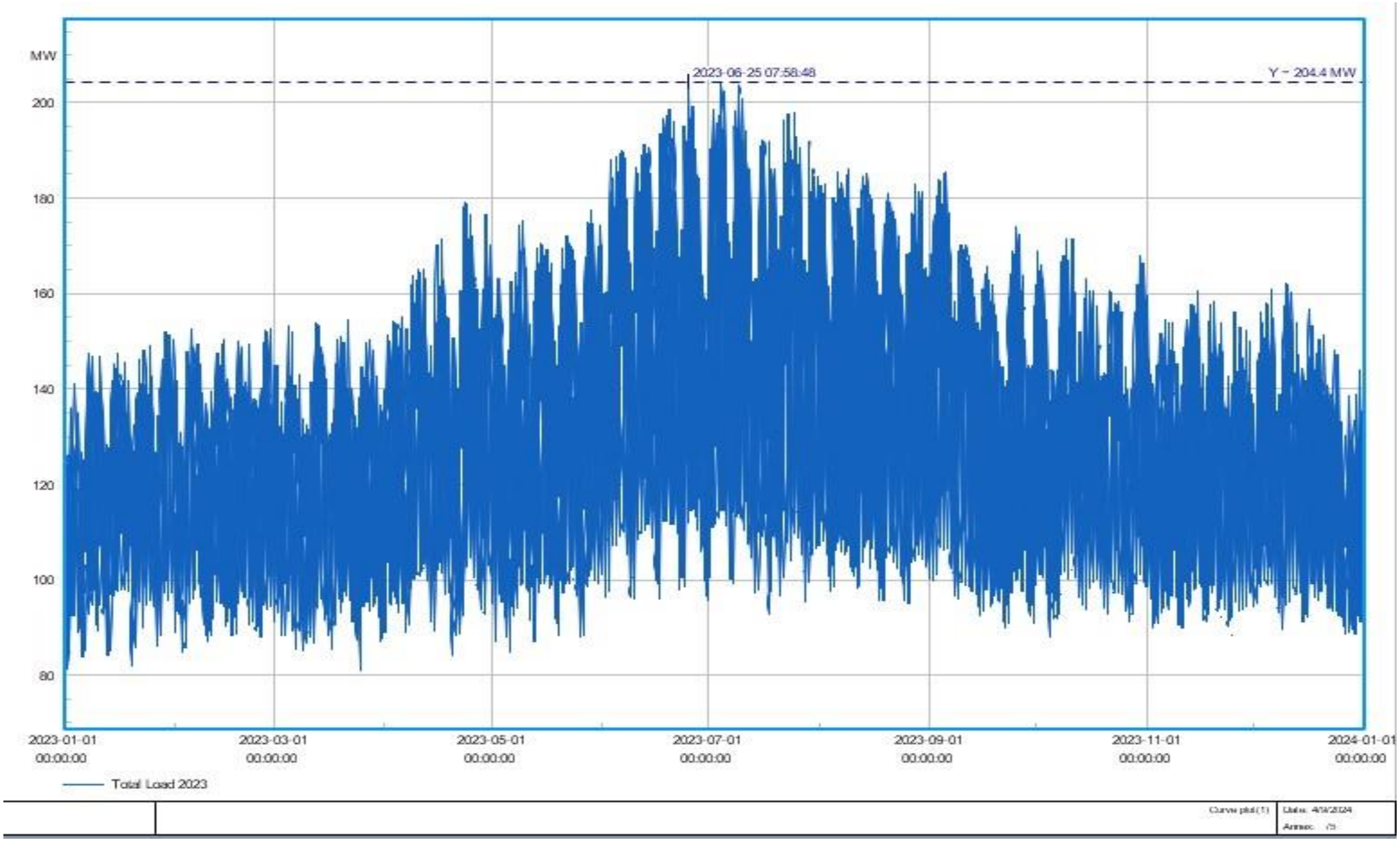


Figure 12: Load profile for year 2023.

Figure 12 shows that power consumption increases significantly from May to September, with June having the highest peak demand. The simulation indicates a peak demand of 204.4 MW, highlighting a critical energy use period. This illustrates the network's dependency on energy imports during peak periods, emphasizing the need for additional capacity and efficiency to satisfy the higher demand during these months.

3.4 Load Profiles for LEC Network

The load demand and projections will be considered and the load profile for the base year and other years will be presented from DIgSILENT simulation where it will show the time for the highest demand in the country and where the demand is lower. For all the years, the load projections will be used to find the load profiles, simulate the load demand and see whether the network will handle the demand with no loadings. Figure 13 depicts the load duration curve for 2023, where less than 10% of the time the load demand is around its peak range of 160-204 MW and 99% of the time, the load demand is around 88 MW. The same simulation was conducted for the years 2030 and 2035. Using the most likely scenario of expansion from the study by Mpholo [76] which assumes a GDP growth rate of 4.0% per year. The peak demand from the simulation will be 231.4 MW in 2030. This shows that most of the electricity is imported during this high demand period. The peak demand from the simulation is 255 MW in 2035.

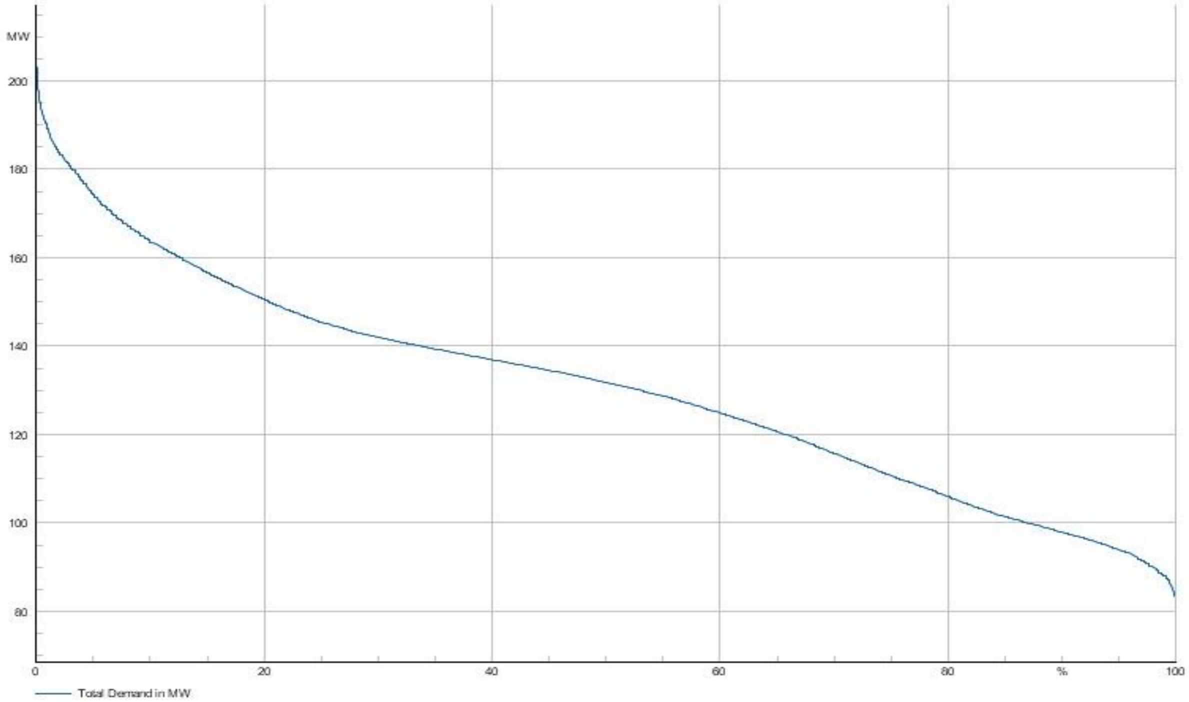


Figure 13: Load duration curve for 2023.

For calculating the voltages and loads at the terminal points, the active power (P) and reactive power (Q) are considered and found using Equations (10) and (11).

$$P = P_0 \left(\frac{V}{V_0}\right)^a \qquad (10)$$

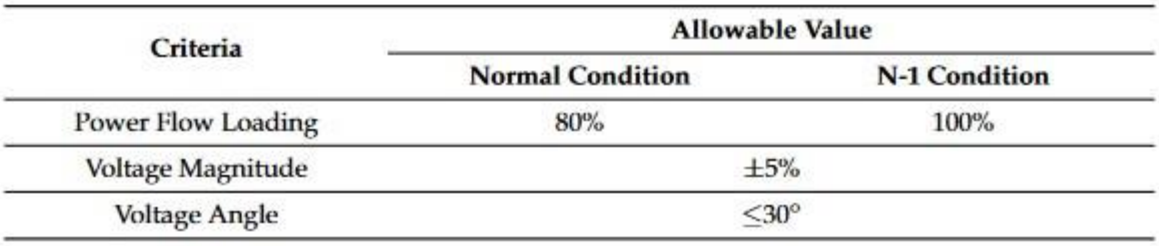
$$Q = Q_0 \left(\frac{V}{V_0}\right)^b \qquad (11)$$

where P_0 represents the reference value of active power, Q_0 represents the reference value of reactive power, V is the instantaneous voltage, V_0 is the nominal voltage, the exponents a and b represent the constant power, current, and impedance of values 0, 1, and 2 [11].

3.5 Voltage Profile and Component Loading

The voltage angle in the phasor diagram represents the sinusoidal phase of the corresponding voltages. The presence of line impedance causes a disparity in voltage angles across a transmission line during the transfer of electrical energy. The voltage phase difference between the two ends of the transmission line must not exceed 30 degrees when assessing transmission line designs. Table 6 displays the permissible values of voltage profile and line loading for both normal conditions and N-1 situations. The power flow is limited to a maximum of 80% when the voltage magnitude is within a range of plus or minus 5%. N-1 contingency is considered in planning because of the expectation that the system will withstand any disturbance and supply power to the load. Hence, when the N-1 contingency happens and the voltage magnitude limit is plus or minus 5% [77], the power flow limit is 100%. A conductor or line is often upgraded before it reaches a loading level of 95% according to the standard procedure. If a line has surpassed its loading limit, it must be closely monitored until the upgrade occurs [78].

Table 6: Acceptable values for transmission lines loading and voltage profile [5].



Criteria	Allowable Value	
	Normal Condition	N-1 Condition
Power Flow Loading	80%	100%
Voltage Magnitude	±5%	
Voltage Angle	≤30°	

Figure *14* shows the colour coding for different voltage and line loading ranges. The green colour on both low and upper voltages indicates the allowable voltage on the network. For lower voltage, the blue colour indicates voltage below 0.9 p.u; turquoise indicates voltages below 0.95 p.u, and for upper voltage; the yellow colour indicates voltage above 1.05 p.u while the red colour means the busbar voltage level is above 1.1 p.u. For line loading, orange colour indicates that the line is loaded above 80%, while red means that the line is loaded above 90%. This helps to quickly see how much load the lines are carrying and if there are any potential issues. Figure 15 shows the graphical presentation as of the loading range simulations on the DIgSILENT software indicating the colour coding in the network

Lower Limit of Allowed Voltage:

	Lower Voltage ... p.u.	Colour
<=	1.	🟩
<=	0.95	🟦
<=	0.9	🟦

Upper Limit of Allowed Voltage:

	Upper Voltage ... p.u.	Colour
>=	1.	🟩
>=	1.05	🟨
>=	1.1	🟥

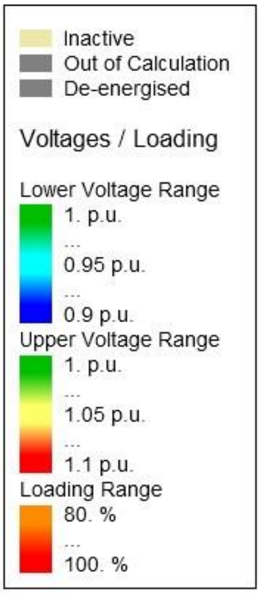
☑ Loading Limits of Edge Elements

Max. Loading of Edge Element:

	Loading Range %	Colour
>=	80.	🟧
>=	100.	🟥

☐ Line Width according to loading

Figure 14: Colour coding for voltages and loadings.



Inactive
Out of Calculation
De-energised

Voltages / Loading

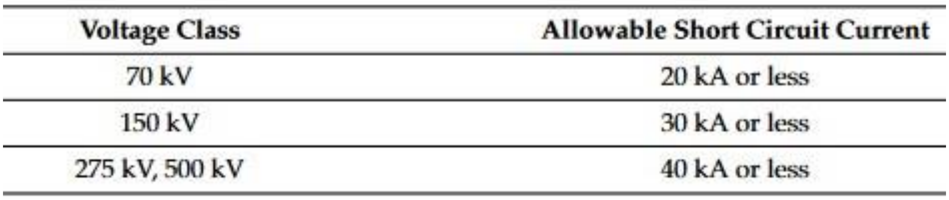
Lower Voltage Range
1. p.u.
...
0.95 p.u.
...
0.9 p.u.
Upper Voltage Range
1. p.u.
...
1.05 p.u.
...
1.1 p.u.
Loading Range
80. %
...
100. %

Figure 15: Graphical presentation of the colour coding on the network.

3.6 Short-circuit Calculations

There are several potential causes of transmission line short circuits, which lead to an unregulated current flow and the potential destruction of equipment. If a three-phase fault occurs, the resulting short circuit will be symmetrical. If a line-to-line, single-line-to-ground, or double-line-to-ground fault occurs, the resulting short circuit will be asymmetrical. It is important to keep in mind that the short-circuit current must not be beyond specific restrictions, as this varies with the voltage level of the transmission line. The LEC network has a maximum voltage level of 132 kV; the allowable short circuit level is simulated and expected to be below the 150 kV voltage class depicted in Table 7.

Table 7: Acceptable currents for short circuits [5].



Voltage Class	Allowable Short Circuit Current
70 kV	20 kA or less
150 kV	30 kA or less
275 kV, 500 kV	40 kA or less

3.7 Contingency Analysis

Contingency analysis is critical in today's energy management. It helps to immediately determine how reliable the power system will be if something such as power outage goes wrong. Using simplified computations, power system planners can examine how the system will perform and whether it can manage the problem. Contingency analysis also examines what happens to the rest of the power system if a transformer, power line or a generator fails [61]. It examines how this outage impacts the load on other lines and the voltage at various points in the system.

3.8 Financial Analysis

The Net Present Value (NPV) of a project is the total sum of the beginning costs and the discounted future costs and income, calculated using algebraic addition. A project that has a positive Net Present Value (NPV) is feasible, and the project with the highest NPV is the most lucrative. Thus, the fundamental principle of lifetime costing involves the process of converting or "discounting" all future income and expenses to their "present value". Equation 12 provides the price of an object after a specific number of years.

$$C_n = C_o(1 + i)^n \qquad (12)$$

Where C_n is the price of an item in n years, i is the inflation rate per unit year, $C_o$is the current price of an item, and n is the number of years.

Equation 13 provides the formula for calculating the NPV of a single future income or expense occurring in a year n.

$$\mathrm{NPV} = C_n \left[1 + {}^{i}/(1 + d)\right]^{n} \qquad (13)$$

Where d is the discount rate per unit year.

The discount rate or the cost of capital represents the expected minimum rate of the returns. Applying equation 13 allows for the acquisition of all anticipated future one-time cash flows. Calculating the NPV involved considering the capital cost of the project, expenses related to the losses, and ongoing maintenance costs.

The transmission line costs used in this study were allocated using the approximate 6.38% inflation rate of Lesotho in 2024 [79]. Table 8 depicts the required investment in transmission lines according to their line type. The costs are associated with the 2009 study on Lesotho's national electrification plan, which was 15 years ago [26]. Table 9 displays the cost of each transformer according to its size. These projected prices have been used to determine the overall investment required when reinforcing the transmission lines and transformers.

Table 8: Projected transmission line costs based on type.

Line Type (kV)	Unit price (USD/km) In 2009	Unit price (USD/km) In 2024	Unit price (USD/km) In 2030	Unit price (USD/km) In 2035
132	65,000.00	**164,366.44**	**238,217.17**	**324,543.56**
88	60,000.00	**151,722.87**	**219,892.78**	**299,578.67**
66	55,000.00	**139,079.29**	**201,568.37**	**274,613.77**
33	50,000.00	**126,435.72**	**183,243.97**	**249,648.89**
11	45,000.00	**113,792.15**	**164,919.58**	**224,684.00**

Table 9: Projected transformer costs based on capacity.

Transformer size (MVA)	Unit Price (USD/piece) in 2009	Unit price (USD/piece) in 2024	Unit price (USD/piece) in 2030	Unit price (USD/piece) in 2035

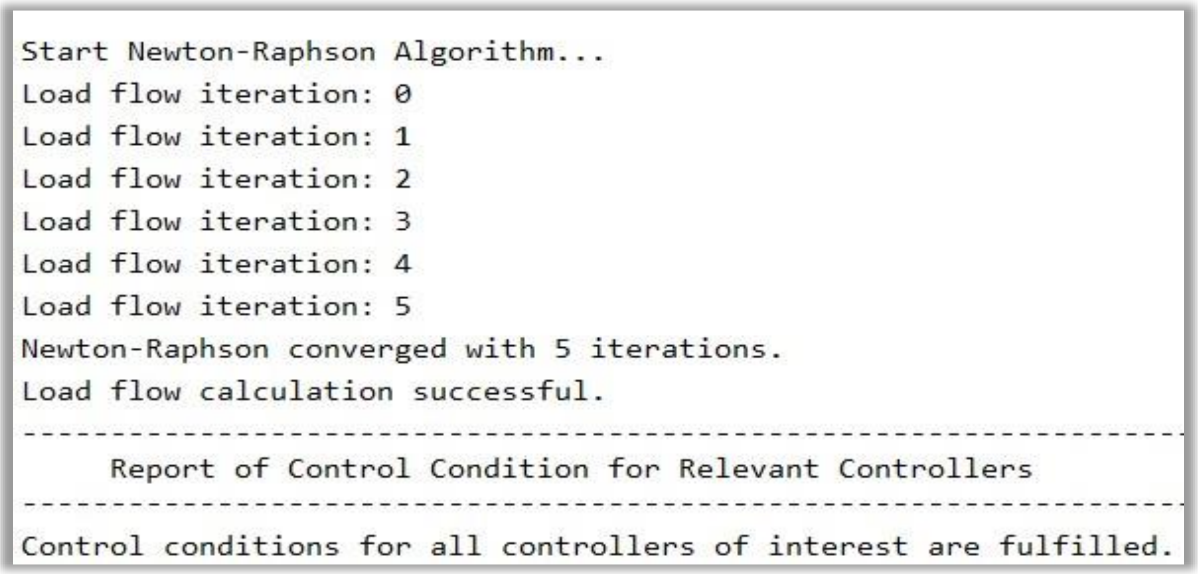
0.5	50,000	**126,435.72**	**183,243.97**	**249,648.89**
2	200,000	**505,742.89**	**732,975.91**	**998,595.56**
5	500,000	**1,264,357.22**	**1,832,439.77**	**2,496,488.96**
10	1,000,000	**2,528,714.45**	**3,664,879.55**	**4,992,977.812**
20	2,000,000	**5,057,428.89**	**7,329,759.09**	**9,985,955.60**
40	4,000,000	**10,114,857.79**	**14,659,518.20**	**19,971,911.23**

4 Results and Discussions

This chapter presents a comprehensive analysis of the Lesotho power network, which was carried out using DIgSILENT PowerFactory, to assess voltage fluctuations and component loadings, ensuring optimal power flow throughout the system from 2023 to 2035. The modelling process involved a thorough assessment of voltage variances based on grid code standards, as well as an evaluation of transformer and transmission line loadings. The analysis applied a threshold of 80% for power flow, which meant that any component that exceeded this limit was highlighted for reinforcement. To guarantee cost-effective system changes, an economic analysis of the necessary modifications was performed for each of these components.

4.1 LEC Network Load Flow Analysis

To simulate the load flow analysis for the years 2030 and 2035, the projected load increases of 36% and 54%, respectively, were applied based on anticipated peak demand growth. These projections reflect the expected rise in electricity consumption driven by population growth, economic development, and increased industrial activity. By integrating these load increases into the model, the study ensures that the network's capacity to handle future demand is accurately assessed. Eight operation scenarios have been simulated in the DIgSILENT PowerFactory, considering the base case scenario, the emergency case and the development case scenarios for three reference years. The quasi-dynamic simulation was conducted to determine the maximum component loading on the network. The results of the quasi-dynamic simulation indicate the specific locations and times at which the loadings will occur. The Newton-Raphson method was used to perform the load flow analysis, and it was found to converge after five iterations where all control conditions for all controllers of interest are fulfilled, as shown in Figure 16.



```
Start Newton-Raphson Algorithm...
Load flow iteration: 0
Load flow iteration: 1
Load flow iteration: 2
Load flow iteration: 3
Load flow iteration: 4
Load flow iteration: 5
Newton-Raphson converged with 5 iterations.
Load flow calculation successful.
-------------------------------------------------------------
     Report of Control Condition for Relevant Controllers
-------------------------------------------------------------
Control conditions for all controllers of interest are fulfilled.
```

Figure 16: Newton-Raphson method for analysing load flow.

Figure 17 depicts the LEC network topology for 2023, with the ’Muela Hydropower and Ramarothole Solar PV Farm serving as the only generators in the country. The load flow models show no thermal loadings on the transmission lines. The loadings presented in Figure 17 show the annual load flow in the lines, where the 33 kV line from ’Muela to Khukhune is the line with the highest average loading of 26.7%, followed by a 33 kV line from Mabote substation to Highway at 22.6%. The rest of the loadings show proper transfer of power.

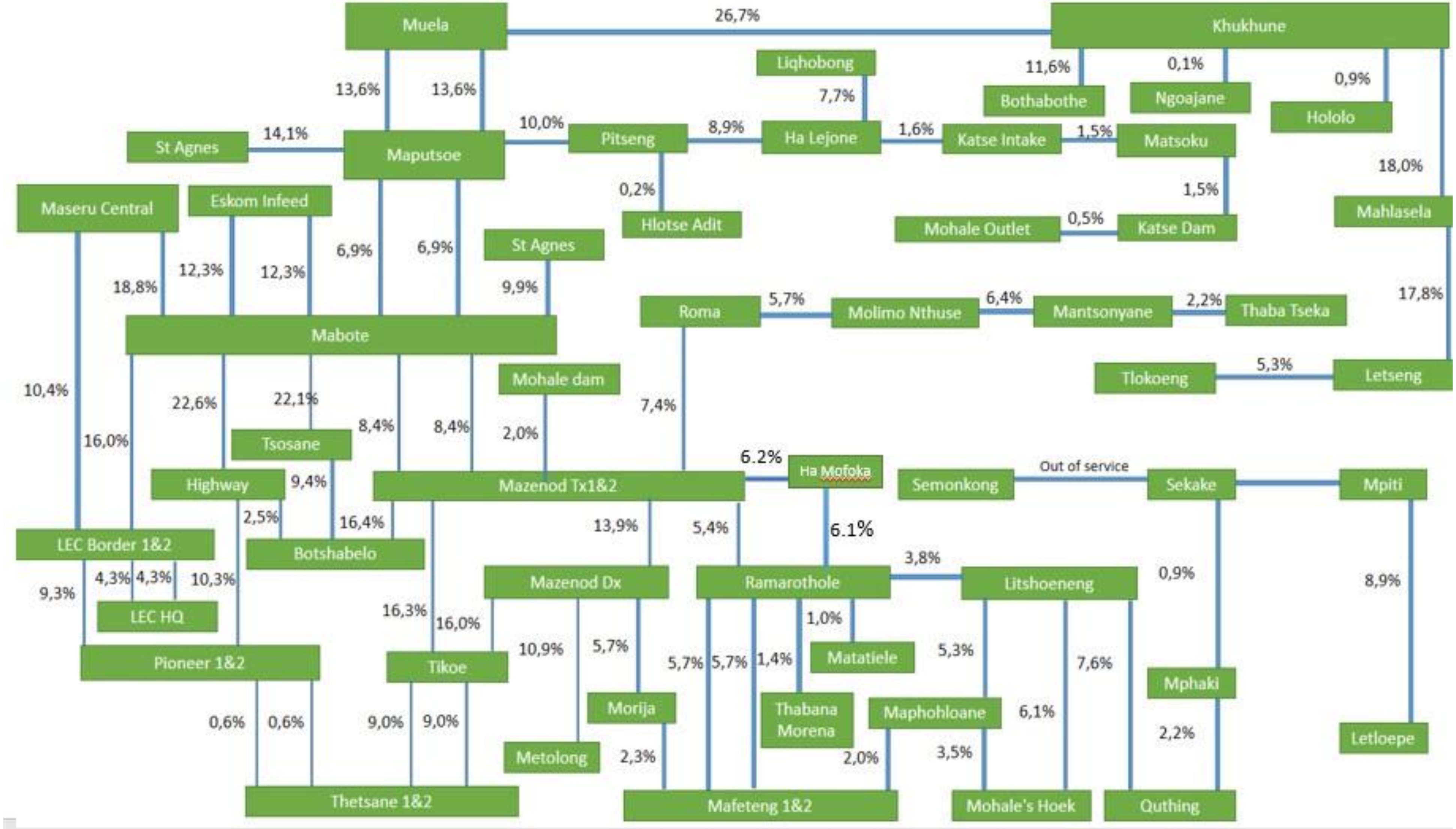


Figure 17: Load flow analysis on the LEC network with Muela Hydro and Ramarothole PV.

4.2 Base Case Criteria Evaluation

This section presents the simulation results for network variations and component loadings, considering the main generators: 'Muela Hydropower (72 MW), Ramarothole Solar PV (30 MW), and imports from Eskom and EdM for the years 2023, 2030, and 2035. Table 10 shows the results of the substations and busbars which were not compliant during the simulation where the voltage limits were set between 0.95 and 1.05 p.u and the component loadings at 80 and 100%. The detailed analysis showing the violated compliance conditions are shown in Table 11, Table 12, Table 13, Table 14, Table 15 and Table 16 for the base case scenario.

Table 10: The base case criteria evaluation

Base Case Simulation	**Compliance Conditions**	**Non-Compliant Substations**		
		2023	**2030**	**2035**
		< 0.95p.u		
Voltage Violations(Busbars)	0.95p.u -1.05 p.u	Roma	Roma	Roma
		Quthing	Quthing	Quthing
		Sekake	Sekake	Sekake
		Mphaki	Mphaki	Mphaki
		Molimo Nthuse	Molimo Nthuse	Molimo Nthuse
		Mohale’s Hoek	Mohale’s Hoek	Mohale’s Hoek
		Litsoeneng	Litsoeneng	Litsoeneng
		Maphohloane	Maphohloane	Maphohloane
		Thaba Tseka	Thaba Tseka	Thaba Tseka
			Mantsonyane	Mantsonyane
Component Loading (Transmission lines/transformers)	≤ 80%	**> 80%**		
		Letloepe	Letloepe	Letloepe
		Morija	Morija	Morija
		Mazenod Dx	Mazenod Dx	Mazenod Dx
		Thaba Tseka	Thaba Tseka	Thaba Tseka
		Maseru Central	Maseru Central	Maseru Central
		Mabote to Maseru Central	Mabote to Maseru Central	Mabote to Maseru Central

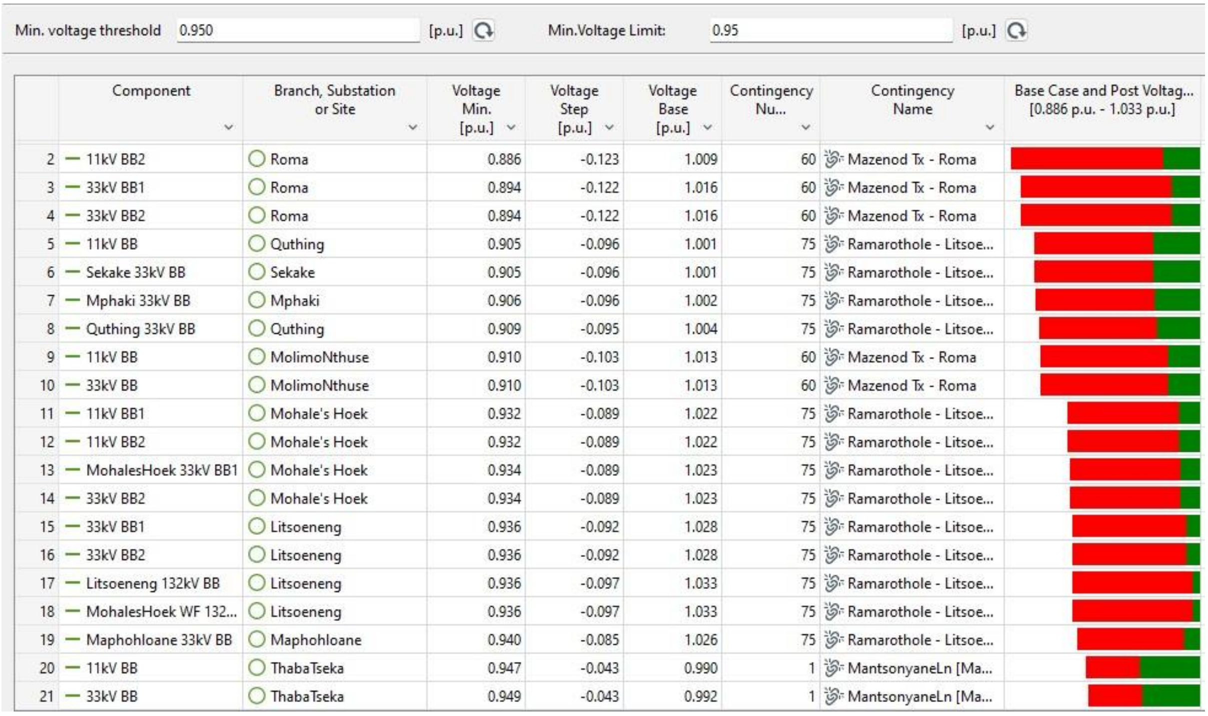
		Metolong	Metolong	Metolong
		Pioneer	Pioneer	Pioneer
			Tsosane	Tsosane
			St Agnes	St Agnes
			Botshabelo	Botshabelo
			Maputsoe	Maputsoe
			Thetsane	Thetsane
				Hlotse
				Mabote
				Mabote to LCE Border
				Mafeteng
				Mabote to Highway
				Highway

4.2.1 Base Case Contingency Analysis with Voltage Results for the 2023 Load

The contingency analysis was simulated in the network for the 2023 load. There were no contingency elements with loading above 80% and no terminals with a voltage above 1.05 p.u. However, Table 11 shows the elements that violated the emergency conditions with minimum voltage requirements of 0.95 p.u at the base case. From Table 11, when the transmission line from Mazenod Tx to Roma experiences an outage, the 11 kV and 33 kV busbars at Roma will operate with a minimum of 0.886 p.u and 0.894 p.u and when it is operational there will be a -0.123 and -0.122 p.u voltage step up which will lead to the busbar operating at 1.009 and 1.016 p.u at the base case respectively. These are the only busbars operating below the emergency conditions and should be considered when improving the network. When the line from Ramarothole to Litsoeneng experiences an outage, the 132 kV busbar at Litsoeneng will operate with a minimum voltage of 0.936 p.u. and when the line is operating properly, there will be a -0.097 p.u voltage step up to 1.033 p.u at the base case. These voltage violations should be considered critical. Figure 18 shows the schematic results of the simulation. As indicated in

Figure *14*, the green colour shows that the system is stable between 0.95 and 1.05 p.u. The simulation shows that the system is mostly stable at the base case with ten substations performing below 0.95 p.u. The blue colour shows that the voltage is below 0.9 p.u, while the turquoise colour shows that the busbar voltages are below 0.95 p.u.

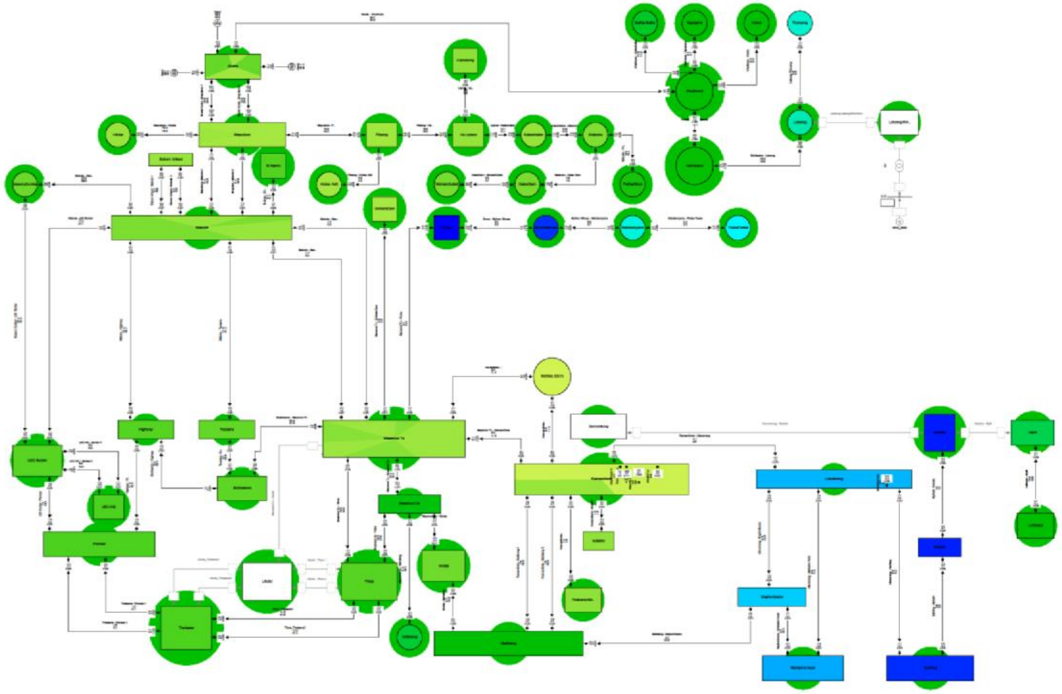
Table 11: Voltage violations below 0.95 p.u for the base case simulations.



Min. voltage threshold 0.950 [p.u.]

Min.Voltage Limit: 0.95 [p.u.]

	Component	Branch, Substation or Site	Voltage Min. [p.u.]	Voltage Step [p.u.]	Voltage Base [p.u.]	Contingency Nu...	Contingency Name	Base Case and Post Voltag... [0.886 p.u. - 1.033 p.u.]
2	— 11kV BB2	○ Roma	0.886	-0.123	1.009	60	Mazenod Tx - Roma	🟥🟩
3	— 33kV BB1	○ Roma	0.894	-0.122	1.016	60	Mazenod Tx - Roma	🟥🟩
4	— 33kV BB2	○ Roma	0.894	-0.122	1.016	60	Mazenod Tx - Roma	🟥🟩
5	— 11kV BB	○ Quthing	0.905	-0.096	1.001	75	Ramarothole - Litsoe...	🟥🟩
6	— Sekake 33kV BB	○ Sekake	0.905	-0.096	1.001	75	Ramarothole - Litsoe...	🟥🟩
7	— Mphaki 33kV BB	○ Mphaki	0.906	-0.096	1.002	75	Ramarothole - Litsoe...	🟥🟩
8	— Quthing 33kV BB	○ Quthing	0.909	-0.095	1.004	75	Ramarothole - Litsoe...	🟥🟩
9	— 11kV BB	○ MolimoNthuse	0.910	-0.103	1.013	60	Mazenod Tx - Roma	🟥🟩
10	— 33kV BB	○ MolimoNthuse	0.910	-0.103	1.013	60	Mazenod Tx - Roma	🟥🟩
11	— 11kV BB1	○ Mohale's Hoek	0.932	-0.089	1.022	75	Ramarothole - Litsoe...	🟥🟩
12	— 11kV BB2	○ Mohale's Hoek	0.932	-0.089	1.022	75	Ramarothole - Litsoe...	🟥🟩
13	— MohalesHoek 33kV BB1	○ Mohale's Hoek	0.934	-0.089	1.023	75	Ramarothole - Litsoe...	🟥🟩
14	— 33kV BB2	○ Mohale's Hoek	0.934	-0.089	1.023	75	Ramarothole - Litsoe...	🟥🟩
15	— 33kV BB1	○ Litsoeneng	0.936	-0.092	1.028	75	Ramarothole - Litsoe...	🟥🟩
16	— 33kV BB2	○ Litsoeneng	0.936	-0.092	1.028	75	Ramarothole - Litsoe...	🟥🟩
17	— Litsoeneng 132kV BB	○ Litsoeneng	0.936	-0.097	1.033	75	Ramarothole - Litsoe...	🟥🟩
18	— MohalesHoek WF 132...	○ Litsoeneng	0.936	-0.097	1.033	75	Ramarothole - Litsoe...	🟥🟩
19	— Maphohloane 33kV BB	○ Maphohloane	0.940	-0.085	1.026	75	Ramarothole - Litsoe...	🟥🟩
20	— 11kV BB	○ ThabaTseka	0.947	-0.043	0.990	1	MantsonyaneLn [Ma...	🟥🟩
21	— 33kV BB	○ ThabaTseka	0.949	-0.043	0.992	1	MantsonyaneLn [Ma...	🟥🟩



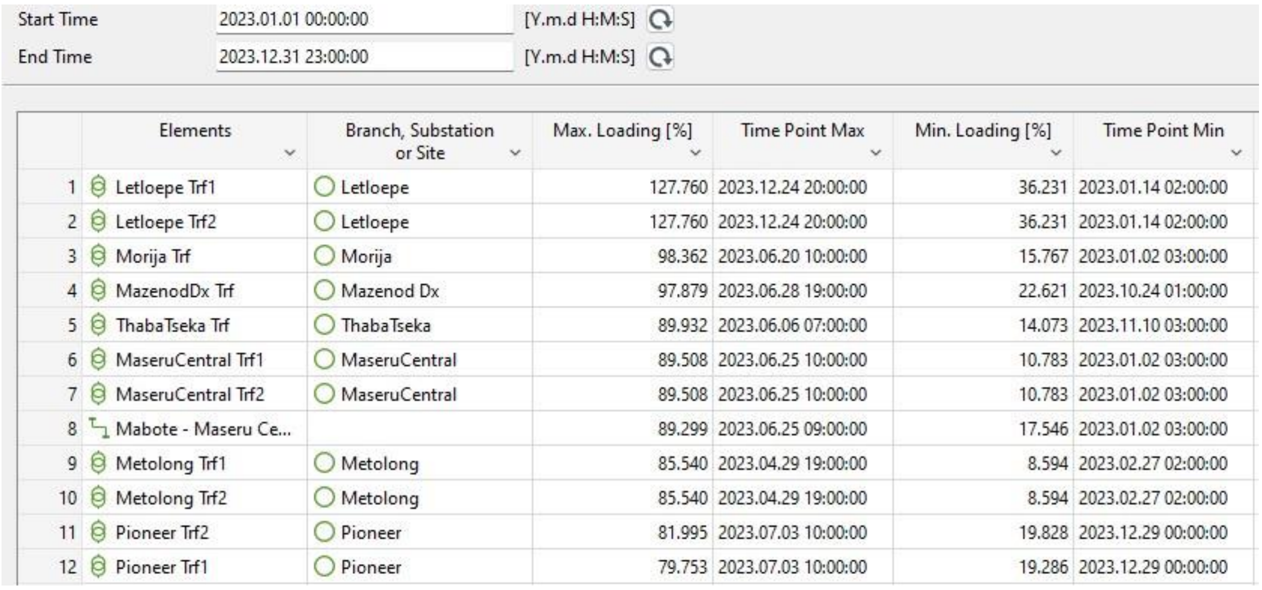
Active Power [MW]
Reactive Power [Mvar]
Current, Magnitude [kA]

Figure 18: Schematic diagram for base case.

4.2.2 Base Case Load Flow Analysis for the 2023 Load

Table 12 presents the maximum thermal loading levels recorded during the quasi-dynamic simulation, considering the ’Muela Hydropower, Ramarothole solar PV and imports from Eskom and EDM as the sources of power. The analysis indicates that only one transmission line violates the 80% limit. The 33 kV line from Mabote to Maseru Central has loadings of 89.30%. The line will need upgrading or the addition of another line to transfer power without thermal loadings. The transformers at Letloepe, with the capacity of 1.6 MVA has a loading of 127.76%. The 10 MVA transformers at Maseru Central were operating at 89.51%. The 10 MVA transformers at Pioneer were operating at 82.0% and 79.75%, which shows that the transformers will need an upgrade to step up or step down the power transferred.

Table 12: Thermal loadings for the base case.



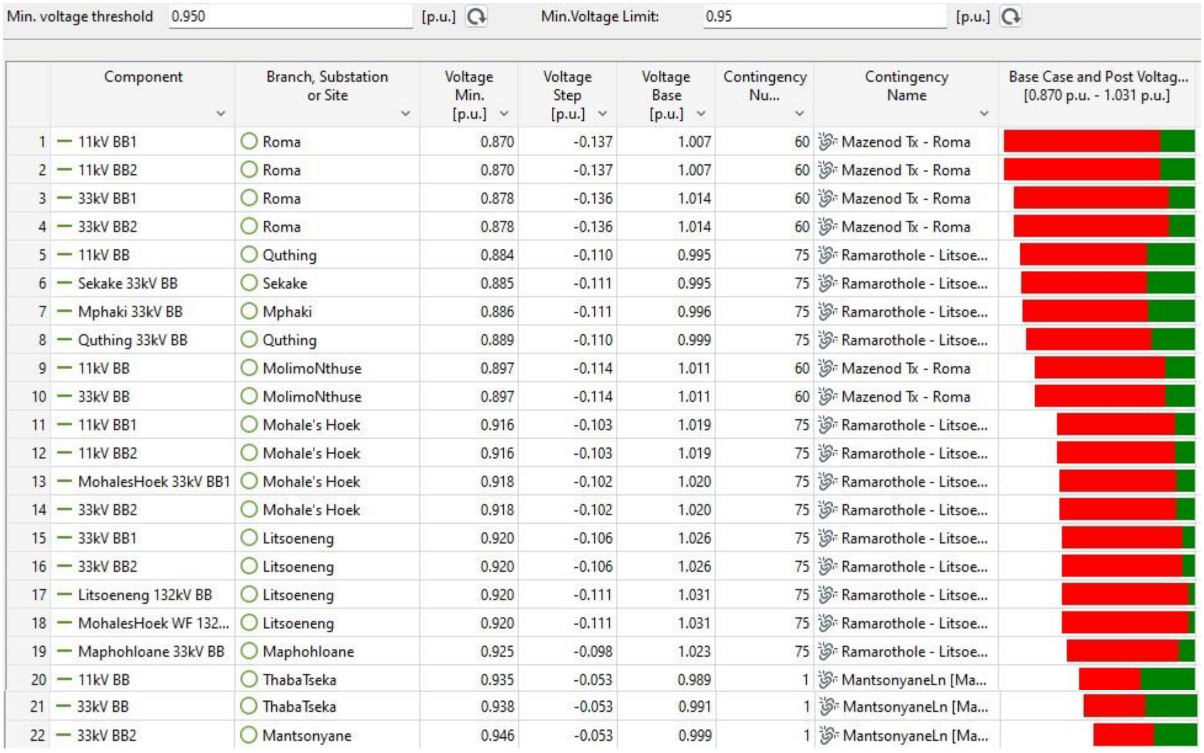
Start Time 2023.01.01 00:00:00 [Y.m.d H:M:S]
End Time 2023.12.31 23:00:00 [Y.m.d H:M:S]

	Elements	Branch, Substation or Site	Max. Loading [%]	Time Point Max	Min. Loading [%]	Time Point Min
1	Letloepe Trf1	Letloepe	127.760	2023.12.24 20:00:00	36.231	2023.01.14 02:00:00
2	Letloepe Trf2	Letloepe	127.760	2023.12.24 20:00:00	36.231	2023.01.14 02:00:00
3	Morija Trf	Morija	98.362	2023.06.20 10:00:00	15.767	2023.01.02 03:00:00
4	MazenodDx Trf	Mazenod Dx	97.879	2023.06.28 19:00:00	22.621	2023.10.24 01:00:00
5	ThabaTseka Trf	ThabaTseka	89.932	2023.06.06 07:00:00	14.073	2023.11.10 03:00:00
6	MaseruCentral Trf1	MaseruCentral	89.508	2023.06.25 10:00:00	10.783	2023.01.02 03:00:00
7	MaseruCentral Trf2	MaseruCentral	89.508	2023.06.25 10:00:00	10.783	2023.01.02 03:00:00
8	Mabote - Maseru Ce...		89.299	2023.06.25 09:00:00	17.546	2023.01.02 03:00:00
9	Metolong Trf1	Metolong	85.540	2023.04.29 19:00:00	8.594	2023.02.27 02:00:00
10	Metolong Trf2	Metolong	85.540	2023.04.29 19:00:00	8.594	2023.02.27 02:00:00
11	Pioneer Trf2	Pioneer	81.995	2023.07.03 10:00:00	19.828	2023.12.29 00:00:00
12	Pioneer Trf1	Pioneer	79.753	2023.07.03 10:00:00	19.286	2023.12.29 00:00:00

4.2.3 Base Case Contingency Analysis with Voltage Results for the 2030 Load

The contingency analysis was simulated for the 2030 load with the base case and there were no contingency elements with loading above 80% and no terminals with voltage above 1.05 p.u. However, Table 13 shows the elements that violated the minimum voltage requirements of 0.95 p.u. From Table 13, it can be depicted that when the line from Mazenod Tx experiences an outage, the 11 kV busbars at Roma will reach a minimum of 0.87 p.u and when the line is operating, there will be a -0.137 p.u voltage step up to 1.007 p.u at the base case. When the line from Ramarothole to Litsoeneng experiences an outage, the 11 kV busbar at Quthing will reach a minimum of 0.884 p.u, and when it is operating, there will be a -0.110 p.u voltage step up to 0.995 p.u at the base case. Compared to Table 11, the busbars in Table 13 show a voltage drop as five substations will be operating below voltage emergency conditions of 0.9 p.u. This is due to the increased load with stagnant power flow. Figure 19 shows the schematic results of the simulation, indicating that most of the time power transfer is stable on the network. Only 11 substations seem to have minimum allowable voltage violations below 0.95 p.u and 6 of them will be operating below emergency conditions and should be considered critical.

Table 13: Voltage violations below 0.95 p.u. from the 2030 simulations.



Min. voltage threshold 0.950 [p.u.]   Min.Voltage Limit: 0.95 [p.u.]

	Component	Branch, Substation or Site	Voltage Min. [p.u.]	Voltage Step [p.u.]	Voltage Base [p.u.]	Contingency Nu...	Contingency Name	Base Case and Post Voltag... [0.870 p.u. - 1.031 p.u.]
1	11kV BB1	Roma	0.870	-0.137	1.007	60	Mazenod Tx - Roma	🟥🟩
2	11kV BB2	Roma	0.870	-0.137	1.007	60	Mazenod Tx - Roma	🟥🟩
3	33kV BB1	Roma	0.878	-0.136	1.014	60	Mazenod Tx - Roma	🟥🟩
4	33kV BB2	Roma	0.878	-0.136	1.014	60	Mazenod Tx - Roma	🟥🟩
5	11kV BB	Quthing	0.884	-0.110	0.995	75	Ramarothole - Litsoe...	🟥🟩
6	Sekake 33kV BB	Sekake	0.885	-0.111	0.995	75	Ramarothole - Litsoe...	🟥🟩
7	Mphaki 33kV BB	Mphaki	0.886	-0.111	0.996	75	Ramarothole - Litsoe...	🟥🟩
8	Quthing 33kV BB	Quthing	0.889	-0.110	0.999	75	Ramarothole - Litsoe...	🟥🟩
9	11kV BB	MolimoNthuse	0.897	-0.114	1.011	60	Mazenod Tx - Roma	🟥🟩
10	33kV BB	MolimoNthuse	0.897	-0.114	1.011	60	Mazenod Tx - Roma	🟥🟩
11	11kV BB1	Mohale's Hoek	0.916	-0.103	1.019	75	Ramarothole - Litsoe...	🟥🟩
12	11kV BB2	Mohale's Hoek	0.916	-0.103	1.019	75	Ramarothole - Litsoe...	🟥🟩
13	MohalesHoek 33kV BB1	Mohale's Hoek	0.918	-0.102	1.020	75	Ramarothole - Litsoe...	🟥🟩
14	33kV BB2	Mohale's Hoek	0.918	-0.102	1.020	75	Ramarothole - Litsoe...	🟥🟩
15	33kV BB1	Litsoeneng	0.920	-0.106	1.026	75	Ramarothole - Litsoe...	🟥🟩
16	33kV BB2	Litsoeneng	0.920	-0.106	1.026	75	Ramarothole - Litsoe...	🟥🟩
17	Litsoeneng 132kV BB	Litsoeneng	0.920	-0.111	1.031	75	Ramarothole - Litsoe...	🟥🟩
18	MohalesHoek WF 132...	Litsoeneng	0.920	-0.111	1.031	75	Ramarothole - Litsoe...	🟥🟩
19	Maphohloane 33kV BB	Maphohloane	0.925	-0.098	1.023	75	Ramarothole - Litsoe...	🟥🟩
20	11kV BB	ThabaTseka	0.935	-0.053	0.989	1	MantsonyaneLn [Ma...	🟥🟩
21	33kV BB	ThabaTseka	0.938	-0.053	0.991	1	MantsonyaneLn [Ma...	🟥🟩
22	33kV BB2	Mantsonyane	0.946	-0.053	0.999	1	MantsonyaneLn [Ma...	🟥🟩

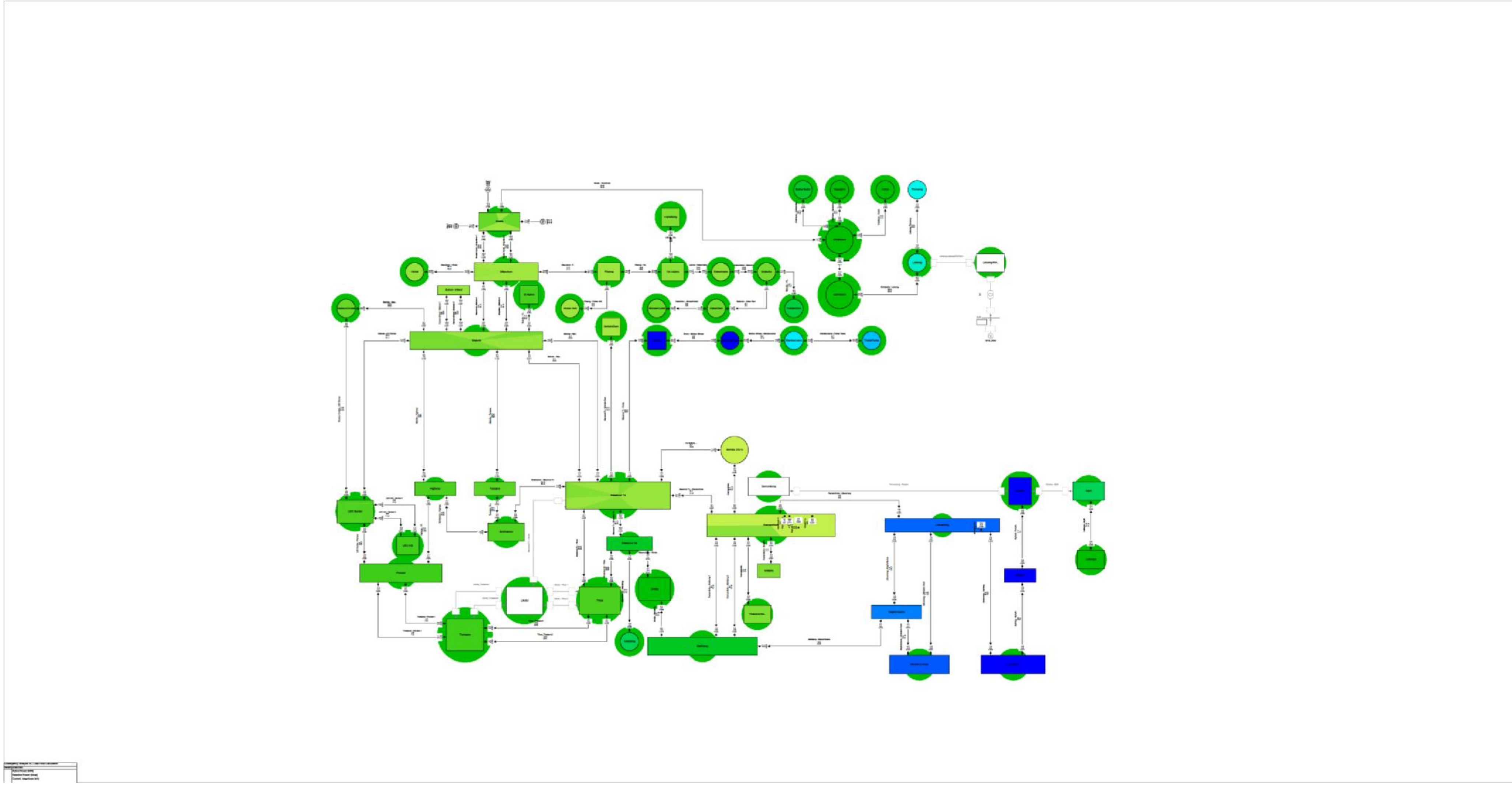
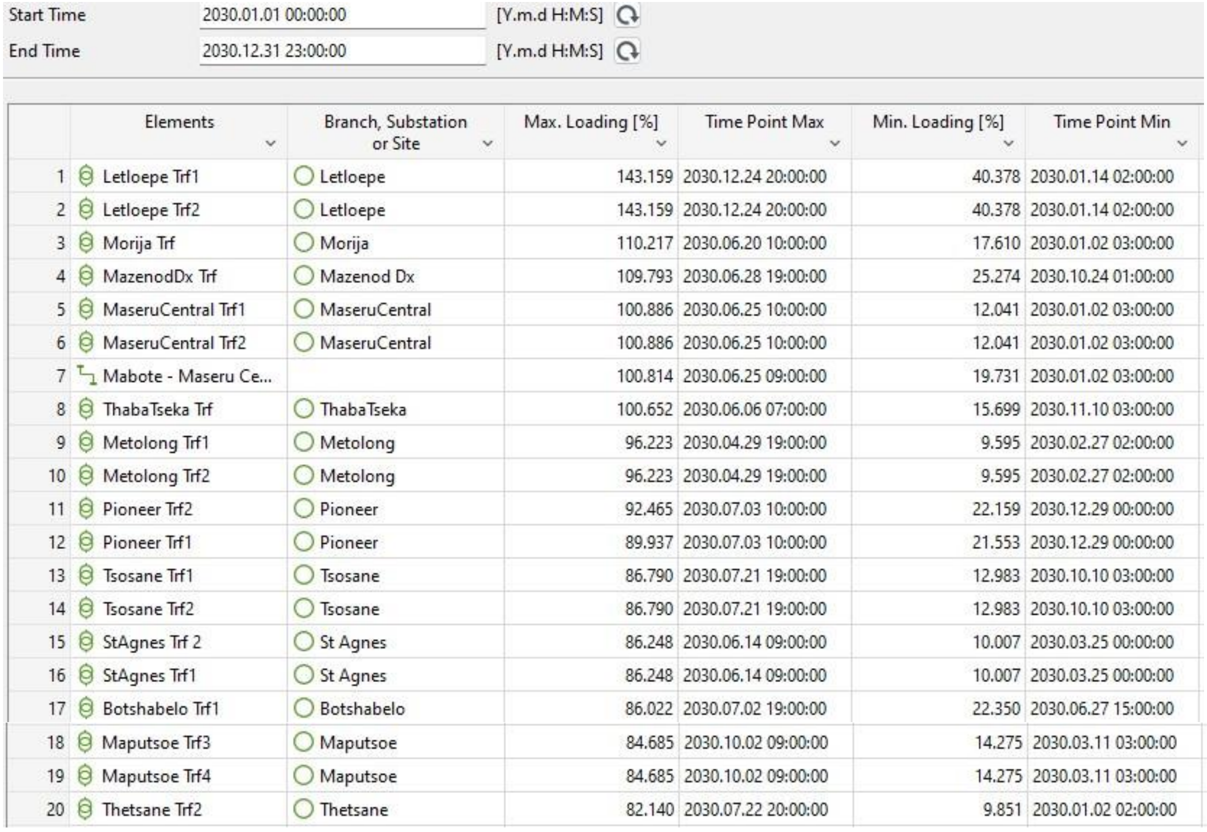


Figure 19: 2030 Schematic diagram with base case.

4.2.4 Base Case Load Flow Analysis for the 2030 Load

A yearly load flow analysis was conducted for 2030 and no thermal breaches were observed in the network since all line loadings were below 30%. Table 14 displays the projected thermal loadings during the periods of peak demand that will follow in the absence of any enhancements to the transmission lines or transformers. The 33 kV Mabote to Maseru Central line will have a percentage increase from 89.3 to 100.81%. This line needs to be upgraded or a double circuit will be required to minimize the pressure on the line as it becomes critical. The transformers at Letloepe show a 15.40% increase in loading from 127.76 to 143.16%. Since it is only 1.6 MVA, it should be upgraded to avoid further loadings. The 5 MVA transformers at Maputsoe substation will experience 84.69% loading and should be upgraded. The 20 MVA transformer at Thetsane substation will reach 82.14 % loadings and should be upgraded to cater for the 2035 upgrades.

Table 14: 2030 thermal loadings for the base case.



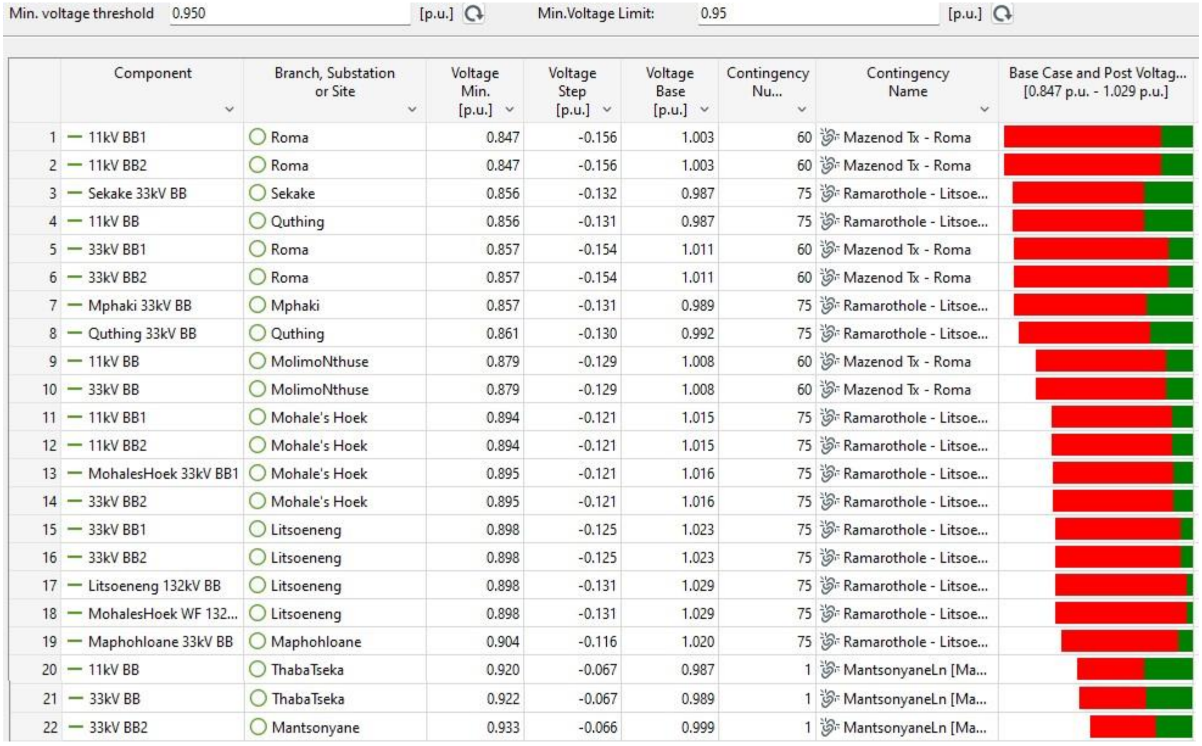
Start Time 2030.01.01 00:00:00 [Y.m.d H:M:S]
End Time 2030.12.31 23:00:00 [Y.m.d H:M:S]

	Elements	Branch, Substation or Site	Max. Loading [%]	Time Point Max	Min. Loading [%]	Time Point Min
1	Letloepe Trf1	Letloepe	143.159	2030.12.24 20:00:00	40.378	2030.01.14 02:00:00
2	Letloepe Trf2	Letloepe	143.159	2030.12.24 20:00:00	40.378	2030.01.14 02:00:00
3	Morija Trf	Morija	110.217	2030.06.20 10:00:00	17.610	2030.01.02 03:00:00
4	MazenodDx Trf	Mazenod Dx	109.793	2030.06.28 19:00:00	25.274	2030.10.24 01:00:00
5	MaseruCentral Trf1	MaseruCentral	100.886	2030.06.25 10:00:00	12.041	2030.01.02 03:00:00
6	MaseruCentral Trf2	MaseruCentral	100.886	2030.06.25 10:00:00	12.041	2030.01.02 03:00:00
7	Mabote - Maseru Ce...		100.814	2030.06.25 09:00:00	19.731	2030.01.02 03:00:00
8	ThabaTseka Trf	ThabaTseka	100.652	2030.06.06 07:00:00	15.699	2030.11.10 03:00:00
9	Metolong Trf1	Metolong	96.223	2030.04.29 19:00:00	9.595	2030.02.27 02:00:00
10	Metolong Trf2	Metolong	96.223	2030.04.29 19:00:00	9.595	2030.02.27 02:00:00
11	Pioneer Trf2	Pioneer	92.465	2030.07.03 10:00:00	22.159	2030.12.29 00:00:00
12	Pioneer Trf1	Pioneer	89.937	2030.07.03 10:00:00	21.553	2030.12.29 00:00:00
13	Tsosane Trf1	Tsosane	86.790	2030.07.21 19:00:00	12.983	2030.10.10 03:00:00
14	Tsosane Trf2	Tsosane	86.790	2030.07.21 19:00:00	12.983	2030.10.10 03:00:00
15	StAgnes Trf 2	St Agnes	86.248	2030.06.14 09:00:00	10.007	2030.03.25 00:00:00
16	StAgnes Trf1	St Agnes	86.248	2030.06.14 09:00:00	10.007	2030.03.25 00:00:00
17	Botshabelo Trf1	Botshabelo	86.022	2030.07.02 19:00:00	22.350	2030.06.27 15:00:00
18	Maputsoe Trf3	Maputsoe	84.685	2030.10.02 09:00:00	14.275	2030.03.11 03:00:00
19	Maputsoe Trf4	Maputsoe	84.685	2030.10.02 09:00:00	14.275	2030.03.11 03:00:00
20	Thetsane Trf2	Thetsane	82.140	2030.07.22 20:00:00	9.851	2030.01.02 02:00:00

4.2.5 Base Case Contingency Analysis with Voltage Results for the 2035 Load

The contingency analysis was simulated for the 2035 load with the base case and there were no contingency elements with loading above 80% and no terminals with voltage above 1.05 p.u. Table 15 shows the elements that violated the minimum voltage requirements of 0.95 p.u. When the line from Mazenod Tx to Roma experiences an outage, the 11 kV busbar at Roma will be operating with a minimum of 0.847 p.u and when it is operating, there will be a -0.156 p.u voltage step up to 1.003 p.u at the base case. When the line from Ramarothole to Litsoeneng experiences an outage, the 132 kV busbar from Litsoeneng substation will be operating with a minimum of 0.898 p.u, and when it is operating, there will be a -0.131 p.u voltage step up to 1.029 p.u at the base case. From Table 15, it can be depicted that seven substations have busbars with voltage violations below the emergency conditions compared to Table 11 and Table 13. Figure 20 shows the schematic results of the simulation. From Figure 20 there are 11 substations with voltage violations below the allowable voltage conditions of 0.95 p.u and 9 of them will be operating below emergency conditions, which may be critical for the substations if they are not improved.

Table 15: Voltage violations below 0.95 p.u from the 2035 simulations.



Min. voltage threshold 0.950 [p.u.]

Min.Voltage Limit: 0.95 [p.u.]

	Component	Branch, Substation or Site	Voltage Min. [p.u.]	Voltage Step [p.u.]	Voltage Base [p.u.]	Contingency Nu...	Contingency Name	Base Case and Post Voltag... [0.847 p.u. - 1.029 p.u.]
1	11kV BB1	Roma	0.847	-0.156	1.003	60	Mazenod Tx - Roma	🟥🟩
2	11kV BB2	Roma	0.847	-0.156	1.003	60	Mazenod Tx - Roma	🟥🟩
3	Sekake 33kV BB	Sekake	0.856	-0.132	0.987	75	Ramarothole - Litsoe...	🟥🟩
4	11kV BB	Quthing	0.856	-0.131	0.987	75	Ramarothole - Litsoe...	🟥🟩
5	33kV BB1	Roma	0.857	-0.154	1.011	60	Mazenod Tx - Roma	🟥🟩
6	33kV BB2	Roma	0.857	-0.154	1.011	60	Mazenod Tx - Roma	🟥🟩
7	Mphaki 33kV BB	Mphaki	0.857	-0.131	0.989	75	Ramarothole - Litsoe...	🟥🟩
8	Quthing 33kV BB	Quthing	0.861	-0.130	0.992	75	Ramarothole - Litsoe...	🟥🟩
9	11kV BB	MolimoNthuse	0.879	-0.129	1.008	60	Mazenod Tx - Roma	🟥🟩
10	33kV BB	MolimoNthuse	0.879	-0.129	1.008	60	Mazenod Tx - Roma	🟥🟩
11	11kV BB1	Mohale's Hoek	0.894	-0.121	1.015	75	Ramarothole - Litsoe...	🟥🟩
12	11kV BB2	Mohale's Hoek	0.894	-0.121	1.015	75	Ramarothole - Litsoe...	🟥🟩
13	MohalesHoek 33kV BB1	Mohale's Hoek	0.895	-0.121	1.016	75	Ramarothole - Litsoe...	🟥🟩
14	33kV BB2	Mohale's Hoek	0.895	-0.121	1.016	75	Ramarothole - Litsoe...	🟥🟩
15	33kV BB1	Litsoeneng	0.898	-0.125	1.023	75	Ramarothole - Litsoe...	🟥🟩
16	33kV BB2	Litsoeneng	0.898	-0.125	1.023	75	Ramarothole - Litsoe...	🟥🟩
17	Litsoeneng 132kV BB	Litsoeneng	0.898	-0.131	1.029	75	Ramarothole - Litsoe...	🟥🟩
18	MohalesHoek WF 132...	Litsoeneng	0.898	-0.131	1.029	75	Ramarothole - Litsoe...	🟥🟩
19	Maphohloane 33kV BB	Maphohloane	0.904	-0.116	1.020	75	Ramarothole - Litsoe...	🟥🟩
20	11kV BB	ThabaTseka	0.920	-0.067	0.987	1	MantsonyaneLn [Ma...	🟥🟩
21	33kV BB	ThabaTseka	0.922	-0.067	0.989	1	MantsonyaneLn [Ma...	🟥🟩
22	33kV BB2	Mantsonyane	0.933	-0.066	0.999	1	MantsonyaneLn [Ma...	🟥🟩

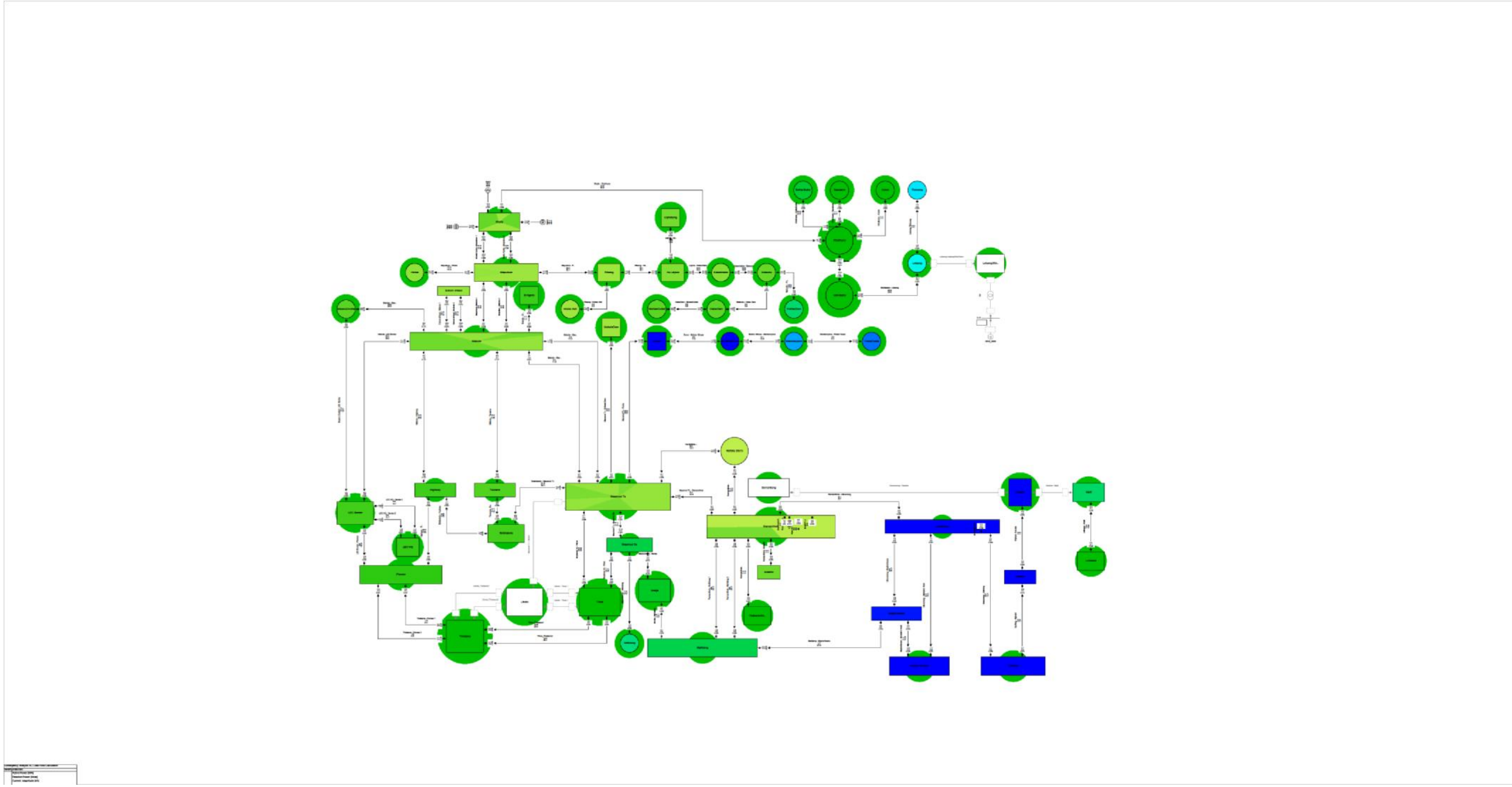
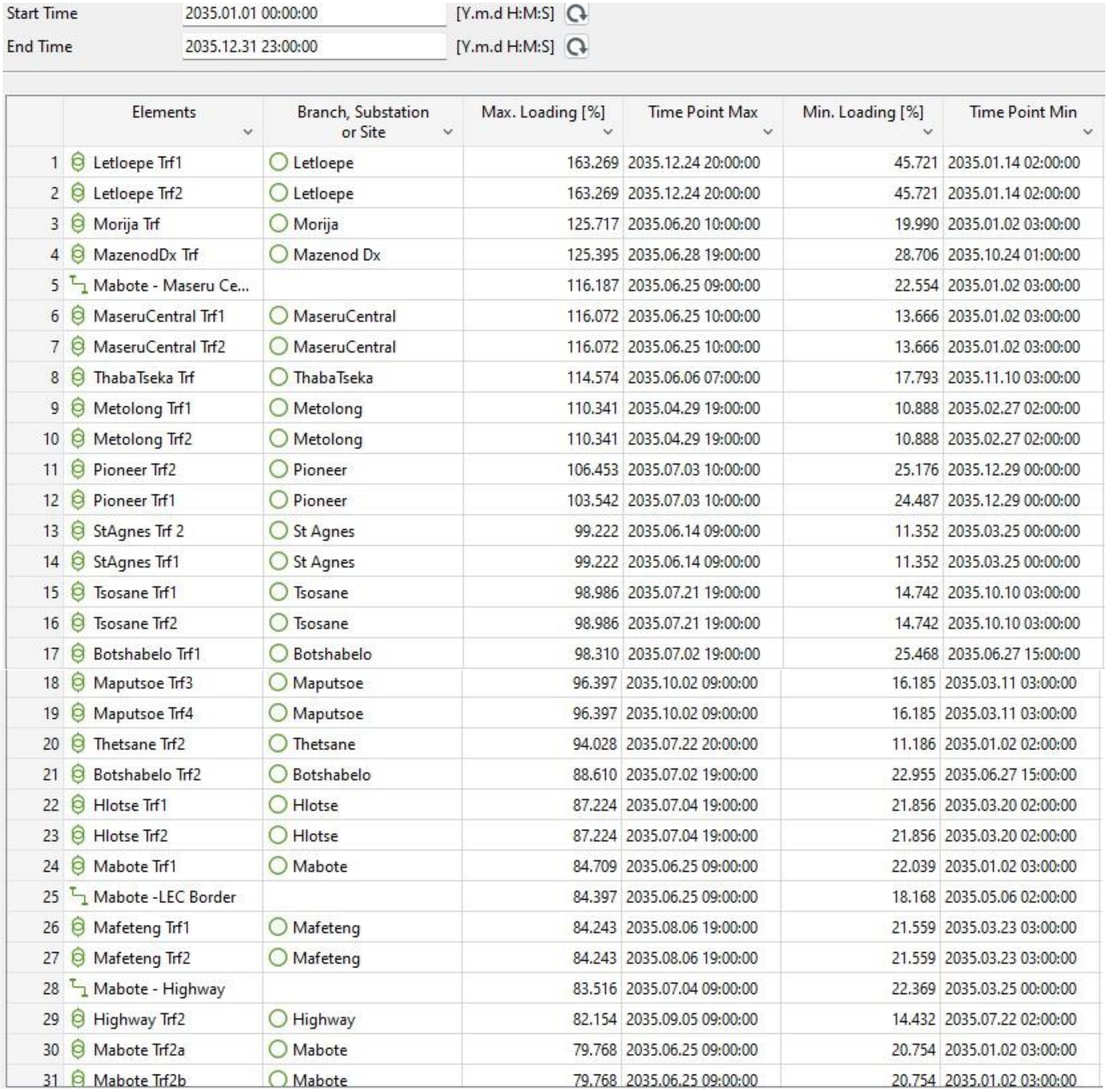


Figure 20 : 2035 schematic diagram with base case.

4.2.6 Base Case Load Flow Analysis for the 2035 Load

Table 16 displays the maximum loadings seen in the network during the projection for the 2035 operational scenario, considering the presence of the ’Muela Hydro and Ramarothole Solar PV and the electricity imports from Eskom. Based on the analysis of the simulations, it is observed that specific transformers consistently encounter their highest loadings simultaneously every year. Table 16 indicates that the Letloepe transformers will face significant overloading in 2035 unless upgrades are made, with a projected loading of 163.27%. The Mazenod Dx transformer will achieve a loading capacity of 125.4%. An additional 10MVA transformer will be essential to supporting the transformers at Mazenod transformers. The line from Mabote to Maseru Central will have a loading capacity of 116.19%, while Mabote to Highway will have a loading capacity of 83.52%. Another line from Mabote to the LEC border has a loading of 84.40%. This may be attributed to increased imports from Eskom Infeed, as the Mabote Substation is the first substation reached when importing power. This means that the ’Muela and Ramarothole solar PV cannot be able to supply the country on their own. The Eskom injection will be required to meet the demand. The 5 MVA transformers at Maputsoe will experience 96.40% loading if not reinforced by 2035. The 5 MVA transformers at the Mafeteng substation will reach a loading of 84.24% if not reinforced. The 40 MVA transformers at the Mabote substation will reach a loading of 79.77% and should be considered critical since most power that is supplied in the country through imports passes through the Mabote transformers. The transformers at the Highway substation will also reach a loading of 82.15%. The data presented in Table 16 shows that if there are no power generators in 2035, there will be more loadings on the network and this may lead to instability in the network.

Table 16: 2035 thermal loadings for the base case.



Start Time 2035.01.01 00:00:00 [Y.m.d H:M:S]

End Time 2035.12.31 23:00:00 [Y.m.d H:M:S]

	Elements	Branch, Substation or Site	Max. Loading [%]	Time Point Max	Min. Loading [%]	Time Point Min
1	Letloepe Trf1	Letloepe	163.269	2035.12.24 20:00:00	45.721	2035.01.14 02:00:00
2	Letloepe Trf2	Letloepe	163.269	2035.12.24 20:00:00	45.721	2035.01.14 02:00:00
3	Morija Trf	Morija	125.717	2035.06.20 10:00:00	19.990	2035.01.02 03:00:00
4	MazenodDx Trf	Mazenod Dx	125.395	2035.06.28 19:00:00	28.706	2035.10.24 01:00:00
5	Mabote - Maseru Ce...		116.187	2035.06.25 09:00:00	22.554	2035.01.02 03:00:00
6	MaseruCentral Trf1	MaseruCentral	116.072	2035.06.25 10:00:00	13.666	2035.01.02 03:00:00
7	MaseruCentral Trf2	MaseruCentral	116.072	2035.06.25 10:00:00	13.666	2035.01.02 03:00:00
8	ThabaTseka Trf	ThabaTseka	114.574	2035.06.06 07:00:00	17.793	2035.11.10 03:00:00
9	Metolong Trf1	Metolong	110.341	2035.04.29 19:00:00	10.888	2035.02.27 02:00:00
10	Metolong Trf2	Metolong	110.341	2035.04.29 19:00:00	10.888	2035.02.27 02:00:00
11	Pioneer Trf2	Pioneer	106.453	2035.07.03 10:00:00	25.176	2035.12.29 00:00:00
12	Pioneer Trf1	Pioneer	103.542	2035.07.03 10:00:00	24.487	2035.12.29 00:00:00
13	StAgnes Trf 2	St Agnes	99.222	2035.06.14 09:00:00	11.352	2035.03.25 00:00:00
14	StAgnes Trf1	St Agnes	99.222	2035.06.14 09:00:00	11.352	2035.03.25 00:00:00
15	Tsosane Trf1	Tsosane	98.986	2035.07.21 19:00:00	14.742	2035.10.10 03:00:00
16	Tsosane Trf2	Tsosane	98.986	2035.07.21 19:00:00	14.742	2035.10.10 03:00:00
17	Botshabelo Trf1	Botshabelo	98.310	2035.07.02 19:00:00	25.468	2035.06.27 15:00:00
18	Maputsoe Trf3	Maputsoe	96.397	2035.10.02 09:00:00	16.185	2035.03.11 03:00:00
19	Maputsoe Trf4	Maputsoe	96.397	2035.10.02 09:00:00	16.185	2035.03.11 03:00:00
20	Thetsane Trf2	Thetsane	94.028	2035.07.22 20:00:00	11.186	2035.01.02 02:00:00
21	Botshabelo Trf2	Botshabelo	88.610	2035.07.02 19:00:00	22.955	2035.06.27 15:00:00
22	Hlotse Trf1	Hlotse	87.224	2035.07.04 19:00:00	21.856	2035.03.20 02:00:00
23	Hlotse Trf2	Hlotse	87.224	2035.07.04 19:00:00	21.856	2035.03.20 02:00:00
24	Mabote Trf1	Mabote	84.709	2035.06.25 09:00:00	22.039	2035.01.02 03:00:00
25	Mabote -LEC Border		84.397	2035.06.25 09:00:00	18.168	2035.05.06 02:00:00
26	Mafeteng Trf1	Mafeteng	84.243	2035.08.06 19:00:00	21.559	2035.03.23 03:00:00
27	Mafeteng Trf2	Mafeteng	84.243	2035.08.06 19:00:00	21.559	2035.03.23 03:00:00
28	Mabote - Highway		83.516	2035.07.04 09:00:00	22.369	2035.03.25 00:00:00
29	Highway Trf2	Highway	82.154	2035.09.05 09:00:00	14.432	2035.07.22 02:00:00
30	Mabote Trf2a	Mabote	79.768	2035.06.25 09:00:00	20.754	2035.01.02 03:00:00
31	Mabote Trf2b	Mabote	79.768	2035.06.25 09:00:00	20.754	2035.01.02 03:00:00

4.3 Emergency Case Criteria Evaluation

This section presents the simulation results for network variations and component loadings, with the main generators offline for the years 2023, 2030, and 2035 when the country only rely on imports. Table 17 shows the results of the substations and busbars which were no-compliant throughout the simulation where the voltage limits were set between 0.9 and 1.1 p.u and the component loadings at 80 and 100%. The detailed analysis showing the violated compliance conditions are shown in Table 18, Table 19, Table 20, Table 21, Table 22 and Table 23 for the emergency case scenario.

Table 17: Emergency case criteria evaluation.

Emergency Case Simulation	**Compliance Conditions**	**Non-Compliant Substations**		
		2023	**2030**	**2035**

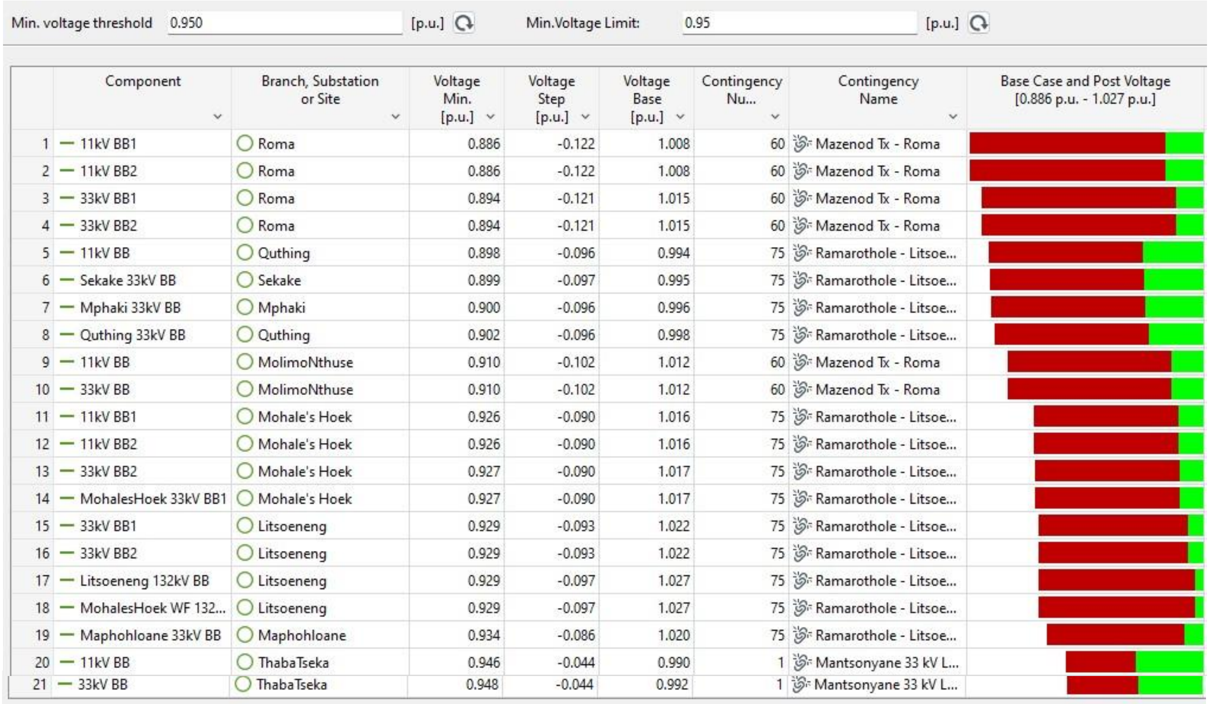
		< 0.9 p.u or < 0.95 p.u		
Voltage Violations (Busbars)	0.9 p.u-1.1 p.u	Roma	Roma	Roma
		Quthing	Quthing	Quthing
		Sekake	Sekake	Sekake
		Mphaki	Mphaki	Mphaki
		Molimo Nthuse	Molimo Nthuse	Molimo Nthuse
		Mohale’s Hoek	Mohale’s Hoek	Mohale’s Hoek
		Litsoeneng	Litsoeneng	Litsoeneng
		Maphohloane	Maphohloane	Maphohloane
		Thaba Tseka	Thaba Tseka	Thaba Tseka
			Mantsonyane	Mantsonyane
Component Loading (Transmission lines/transformers)	≤ 80%	**> 80%**		
		Letloepe	Letloepe	Letloepe
		Morija	Morija	Morija
		Mazenod Dx	Mazenod Dx	Mazenod Dx
		Mabote to Maseru Central	Mabote to Maseru Central	Mabote to Maseru Central
		Thaba Tseka	Maseru Central	Maseru Central
		Maseru Central	Thaba Tseka	Thaba Tseka
		Metolong	Metolong	Metolong
		Pioneer	Pioneer	Pioneer
			Tsosane	St Agnes
			St Agnes	Tsosane
			Botshabelo	Botshabelo
			Maputsoe	Maputsoe
			Eskom Infeed - Mabote	Thetsane
			Thetsane	Eskom Infeed -Mabote
				Hlotse
				Mabote
				Mabote to Highway

				Mabote to LEC Border
				Mafeteng
				Highway

4.3.1 Emergency Case Contingency Analysis with Voltage Results for the 2023 Load

The contingency analysis was simulated for the base case with the generators off. There were no contingency elements with loading above 80% and no terminals with voltage above 1.05 p.u. However, Table 18 shows the elements that violated the minimum voltage requirements of 0.9 and 0.95 p.u. Since it is an emergency condition, the voltages of 0.9 p.u and above is still acceptable on the busbars. When the line from Mazenod Tx to Roma experiences an outage, the 11 kV and 33 kV busbars at Roma will be operating with the minimum voltage of 0.886 and 0.89 p.u, and when it is operating, there will be a -0.122 and -0.121 p.u voltage step up to 1.008 and 1.015 p.u at base case respectively. These are the only busbars operating below 0.9 p.u. The busbars that violated the emergency conditions seem to be further violating them even when the generators are off compared to Table 11. For example, the voltage at the 33 kV busbar at Mohale’s Hoek dropped from 0.934 to 0.927p.u. Figure 21 shows the schematic results of the simulation. There are 9 substations with voltage breaches below the emergency threshold of 0.95 p.u with 2 of them operating below emergency conditions. Most substations function normally.

Table 18: Voltage violations below 0.95 p.u at the base case when generators are off.



Min. voltage threshold 0.950 [p.u.]

Min.Voltage Limit: 0.95 [p.u.]

	Component	Branch, Substation or Site	Voltage Min. [p.u.]	Voltage Step [p.u.]	Voltage Base [p.u.]	Contingency Nu...	Contingency Name	Base Case and Post Voltage [0.886 p.u. - 1.027 p.u.]
1	11kV BB1	Roma	0.886	-0.122	1.008	60	Mazenod Tx - Roma	🟥🟩
2	11kV BB2	Roma	0.886	-0.122	1.008	60	Mazenod Tx - Roma	🟥🟩
3	33kV BB1	Roma	0.894	-0.121	1.015	60	Mazenod Tx - Roma	🟥🟩
4	33kV BB2	Roma	0.894	-0.121	1.015	60	Mazenod Tx - Roma	🟥🟩
5	11kV BB	Quthing	0.898	-0.096	0.994	75	Ramarothole - Litsoe...	🟥🟩
6	Sekake 33kV BB	Sekake	0.899	-0.097	0.995	75	Ramarothole - Litsoe...	🟥🟩
7	Mphaki 33kV BB	Mphaki	0.900	-0.096	0.996	75	Ramarothole - Litsoe...	🟥🟩
8	Quthing 33kV BB	Quthing	0.902	-0.096	0.998	75	Ramarothole - Litsoe...	🟥🟩
9	11kV BB	MolimoNthuse	0.910	-0.102	1.012	60	Mazenod Tx - Roma	🟥🟩
10	33kV BB	MolimoNthuse	0.910	-0.102	1.012	60	Mazenod Tx - Roma	🟥🟩
11	11kV BB1	Mohale's Hoek	0.926	-0.090	1.016	75	Ramarothole - Litsoe...	🟥🟩
12	11kV BB2	Mohale's Hoek	0.926	-0.090	1.016	75	Ramarothole - Litsoe...	🟥🟩
13	33kV BB2	Mohale's Hoek	0.927	-0.090	1.017	75	Ramarothole - Litsoe...	🟥🟩
14	MohalesHoek 33kV BB1	Mohale's Hoek	0.927	-0.090	1.017	75	Ramarothole - Litsoe...	🟥🟩
15	33kV BB1	Litsoeneng	0.929	-0.093	1.022	75	Ramarothole - Litsoe...	🟥🟩
16	33kV BB2	Litsoeneng	0.929	-0.093	1.022	75	Ramarothole - Litsoe...	🟥🟩
17	Litsoeneng 132kV BB	Litsoeneng	0.929	-0.097	1.027	75	Ramarothole - Litsoe...	🟥🟩
18	MohalesHoek WF 132...	Litsoeneng	0.929	-0.097	1.027	75	Ramarothole - Litsoe...	🟥🟩
19	Maphohloane 33kV BB	Maphohloane	0.934	-0.086	1.020	75	Ramarothole - Litsoe...	🟥🟩
20	11kV BB	ThabaTseka	0.946	-0.044	0.990	1	Mantsonyane 33 kV L...	🟥🟩
21	33kV BB	ThabaTseka	0.948	-0.044	0.992	1	Mantsonyane 33 kV L...	🟥🟩

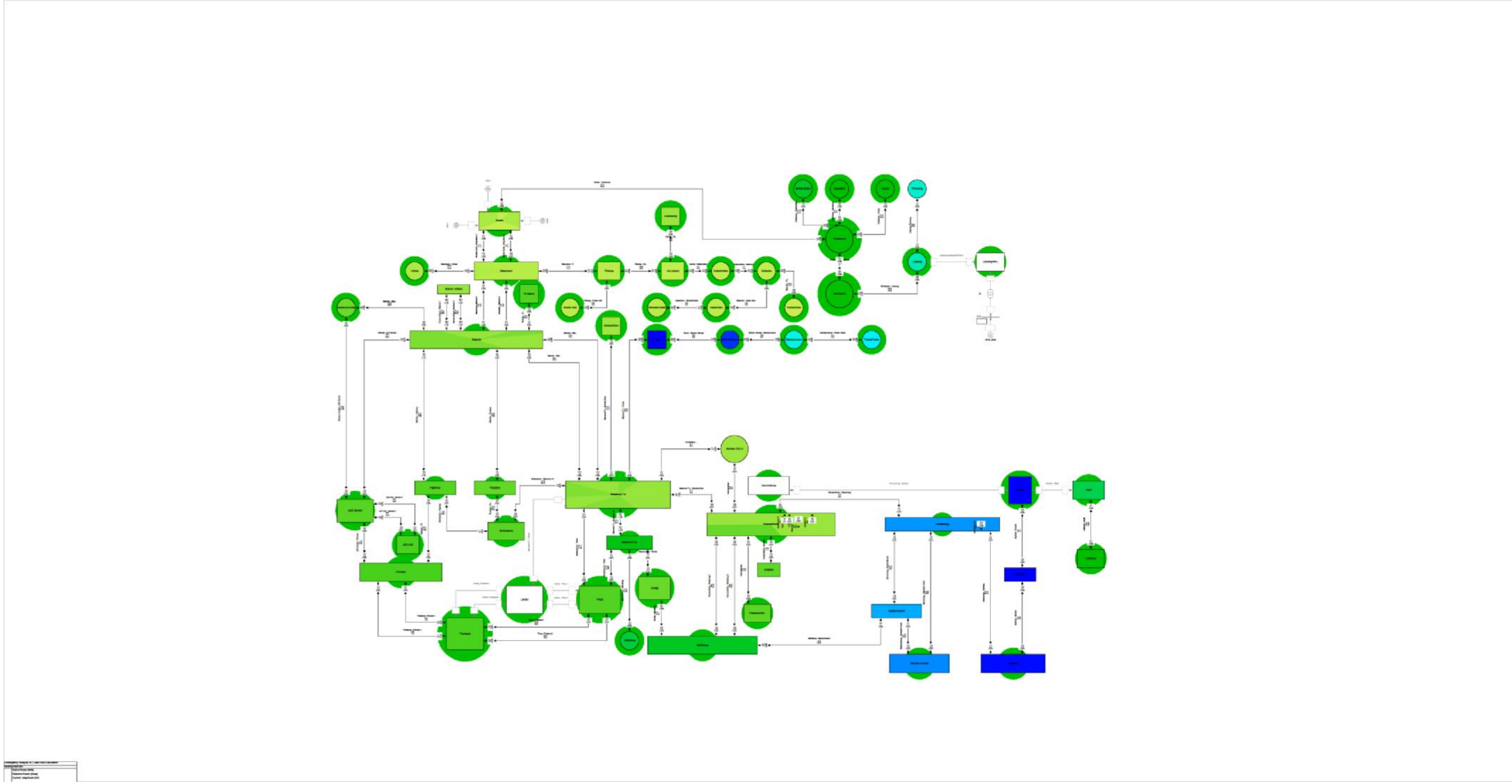


Figure 21: Schematic diagram with generators off for base case.

4.3.2 Emergency Case Load Flow Analysis for the 2023 Load

The load flow analysis was performed for the base case scenario in the LEC network, with the ’Muela generators and Ramarothole PV turned off and the country only relying on imports. The results of the annual load flow analysis indicate that there are no voltage violations or excessive line loadings in the network. However, as shown in Figure 22, the line carrying power from Eskom to the Mabote substation has an annual load flow of 29.8%, while the line from Mabote to Maseru Central has a load flow of 21.5%.

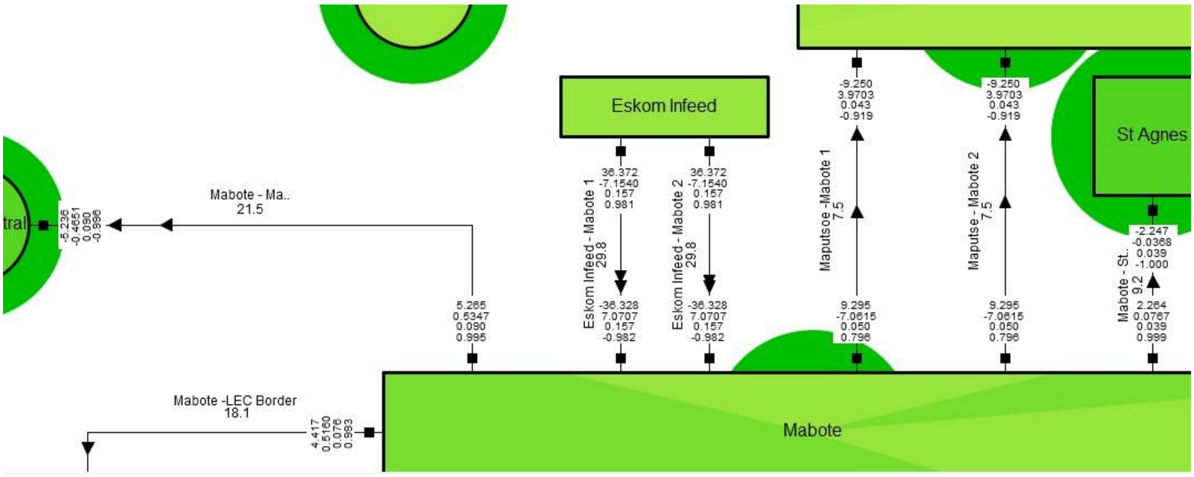
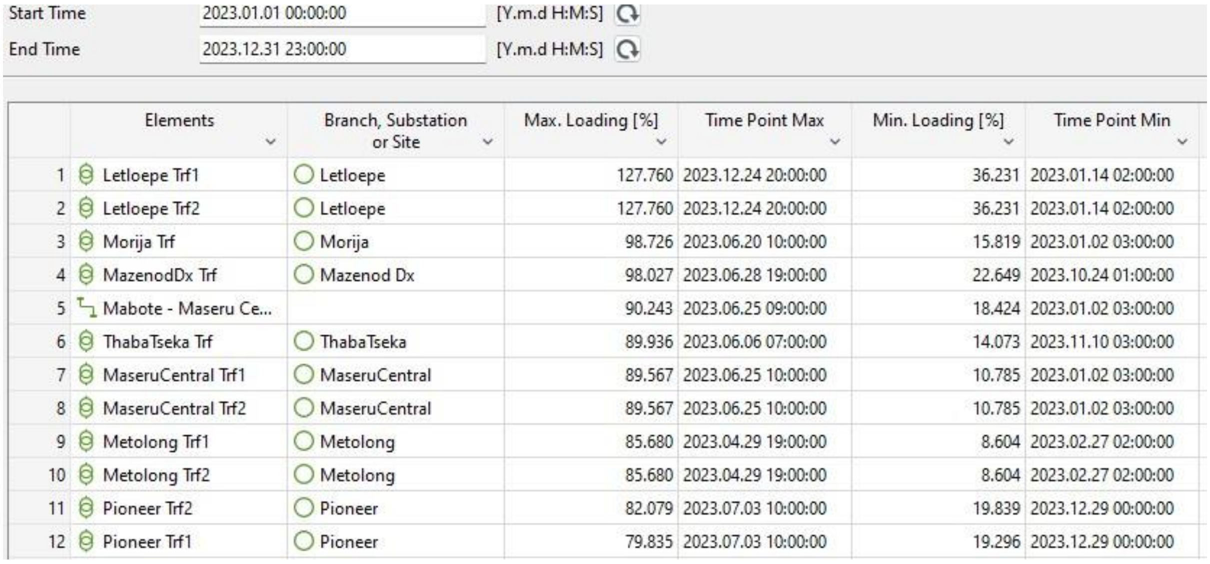


Figure 22: Graphic representation of annual load flow.

Table 19 shows the highest level of loading observed during the simulation when all generators are not operational and the power is imported. The analysis revealed that only one line, specifically the 33 kV line from Mabote to Maseru Central, had thermal loadings exceeding 80% and reaching a loading of 90.24%. This should be considered critical when upgrading the transmission line. The 1.6 MVA transformers at Letloepe had a loading of 127.76% which is similar to the maximum loading on the base case scenario. Pioneer transformers will reach loadings of 82.08% and 79.84%.

Table 19: Maximum loadings when generators are off.



Start Time 2023.01.01 00:00:00 [Y.m.d H:M:S]
End Time 2023.12.31 23:00:00 [Y.m.d H:M:S]

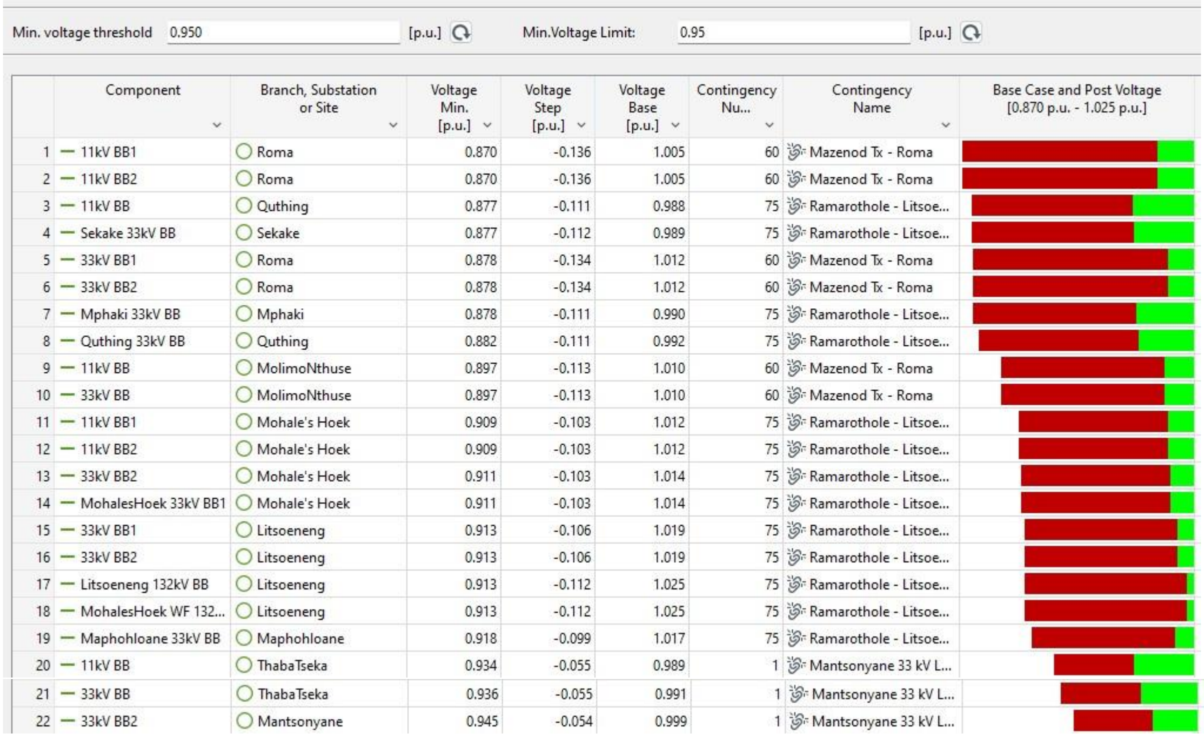
	Elements	Branch, Substation or Site	Max. Loading [%]	Time Point Max	Min. Loading [%]	Time Point Min
1	Letloepe Trf1	Letloepe	127.760	2023.12.24 20:00:00	36.231	2023.01.14 02:00:00
2	Letloepe Trf2	Letloepe	127.760	2023.12.24 20:00:00	36.231	2023.01.14 02:00:00
3	Morija Trf	Morija	98.726	2023.06.20 10:00:00	15.819	2023.01.02 03:00:00
4	MazenodDx Trf	Mazenod Dx	98.027	2023.06.28 19:00:00	22.649	2023.10.24 01:00:00
5	Mabote - Maseru Ce...		90.243	2023.06.25 09:00:00	18.424	2023.01.02 03:00:00
6	ThabaTseka Trf	ThabaTseka	89.936	2023.06.06 07:00:00	14.073	2023.11.10 03:00:00
7	MaseruCentral Trf1	MaseruCentral	89.567	2023.06.25 10:00:00	10.785	2023.01.02 03:00:00
8	MaseruCentral Trf2	MaseruCentral	89.567	2023.06.25 10:00:00	10.785	2023.01.02 03:00:00
9	Metolong Trf1	Metolong	85.680	2023.04.29 19:00:00	8.604	2023.02.27 02:00:00
10	Metolong Trf2	Metolong	85.680	2023.04.29 19:00:00	8.604	2023.02.27 02:00:00
11	Pioneer Trf2	Pioneer	82.079	2023.07.03 10:00:00	19.839	2023.12.29 00:00:00
12	Pioneer Trf1	Pioneer	79.835	2023.07.03 10:00:00	19.296	2023.12.29 00:00:00

4.3.3 Emergency Case Contingency Analysis with Voltage Results for the 2030 Load

The contingency analysis was simulated for 2030 with generators off and there were no contingency elements with loadings above 80% and no terminals with voltages above 1.05 p.u. Table 20 shows the elements that violated the minimum voltage requirements of 0.9 and 0.95 p.u. The lowest voltage in Table 20 is the 11 kV busbar at Roma when the line from Mazenod Tx to Roma experiences an outage with a voltage of 0.870 p.u and when it is operating, there will be a -0.136 p.u voltage step up to 0.1.005 p.u. at the base case. Compared to Table 13, the voltage at the busbars drops significantly when only the imports supply power for the 2030 load. When the line from Ramarothole to Litsoeneng experiences an outage, the 11 kV busbars at Sekake are shown to have dropped at minimum voltage violating the emergency conditions since it has 0.877 p.u and when the line is operating, there will be a -0.112 p.u voltage step up 0.989 p.u at the base case. Figure 23 shows the schematic results of the simulation. According to the diagram, 10 substations have voltage violations of less than 0.95 p.u with 6 of them operating below emergency conditions of 0.9 p.u. This indicates that the busbars operating below the emergency conditions must be considered when only the imports provide power.

The majority of the substations indicated proper power flow.

Table 20: Voltage violation below 0.95 p.u in 2030 when generators are off.



Min. voltage threshold 0.950 [p.u.]

Min.Voltage Limit: 0.95 [p.u.]

	Component	Branch, Substation or Site	Voltage Min. [p.u.]	Voltage Step [p.u.]	Voltage Base [p.u.]	Contingency Nu...	Contingency Name	Base Case and Post Voltage [0.870 p.u. - 1.025 p.u.]
1	11kV BB1	Roma	0.870	-0.136	1.005	60	Mazenod Tx - Roma	🟥🟩
2	11kV BB2	Roma	0.870	-0.136	1.005	60	Mazenod Tx - Roma	🟥🟩
3	11kV BB	Quthing	0.877	-0.111	0.988	75	Ramarothole - Litsoe...	🟥🟩
4	Sekake 33kV BB	Sekake	0.877	-0.112	0.989	75	Ramarothole - Litsoe...	🟥🟩
5	33kV BB1	Roma	0.878	-0.134	1.012	60	Mazenod Tx - Roma	🟥🟩
6	33kV BB2	Roma	0.878	-0.134	1.012	60	Mazenod Tx - Roma	🟥🟩
7	Mphaki 33kV BB	Mphaki	0.878	-0.111	0.990	75	Ramarothole - Litsoe...	🟥🟩
8	Quthing 33kV BB	Quthing	0.882	-0.111	0.992	75	Ramarothole - Litsoe...	🟥🟩
9	11kV BB	MolimoNthuse	0.897	-0.113	1.010	60	Mazenod Tx - Roma	🟥🟩
10	33kV BB	MolimoNthuse	0.897	-0.113	1.010	60	Mazenod Tx - Roma	🟥🟩
11	11kV BB1	Mohale's Hoek	0.909	-0.103	1.012	75	Ramarothole - Litsoe...	🟥🟩
12	11kV BB2	Mohale's Hoek	0.909	-0.103	1.012	75	Ramarothole - Litsoe...	🟥🟩
13	33kV BB2	Mohale's Hoek	0.911	-0.103	1.014	75	Ramarothole - Litsoe...	🟥🟩
14	MohalesHoek 33kV BB1	Mohale's Hoek	0.911	-0.103	1.014	75	Ramarothole - Litsoe...	🟥🟩
15	33kV BB1	Litsoeneng	0.913	-0.106	1.019	75	Ramarothole - Litsoe...	🟥🟩
16	33kV BB2	Litsoeneng	0.913	-0.106	1.019	75	Ramarothole - Litsoe...	🟥🟩
17	Litsoeneng 132kV BB	Litsoeneng	0.913	-0.112	1.025	75	Ramarothole - Litsoe...	🟥🟩
18	MohalesHoek WF 132...	Litsoeneng	0.913	-0.112	1.025	75	Ramarothole - Litsoe...	🟥🟩
19	Maphohloane 33kV BB	Maphohloane	0.918	-0.099	1.017	75	Ramarothole - Litsoe...	🟥🟩
20	11kV BB	ThabaTseka	0.934	-0.055	0.989	1	Mantsonyane 33 kV L...	🟥🟩
21	33kV BB	ThabaTseka	0.936	-0.055	0.991	1	Mantsonyane 33 kV L...	🟥🟩
22	33kV BB2	Mantsonyane	0.945	-0.054	0.999	1	Mantsonyane 33 kV L...	🟥🟩

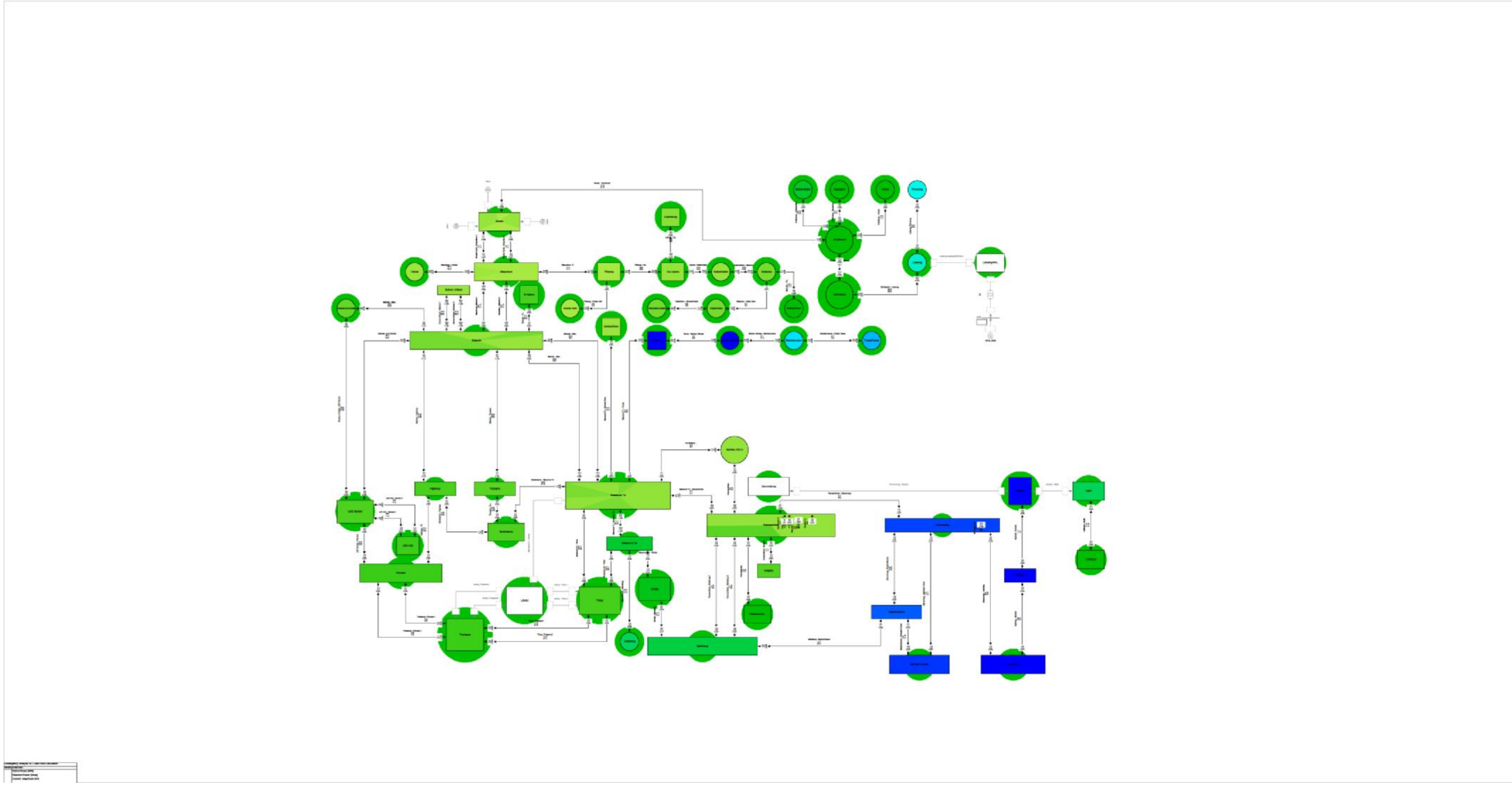
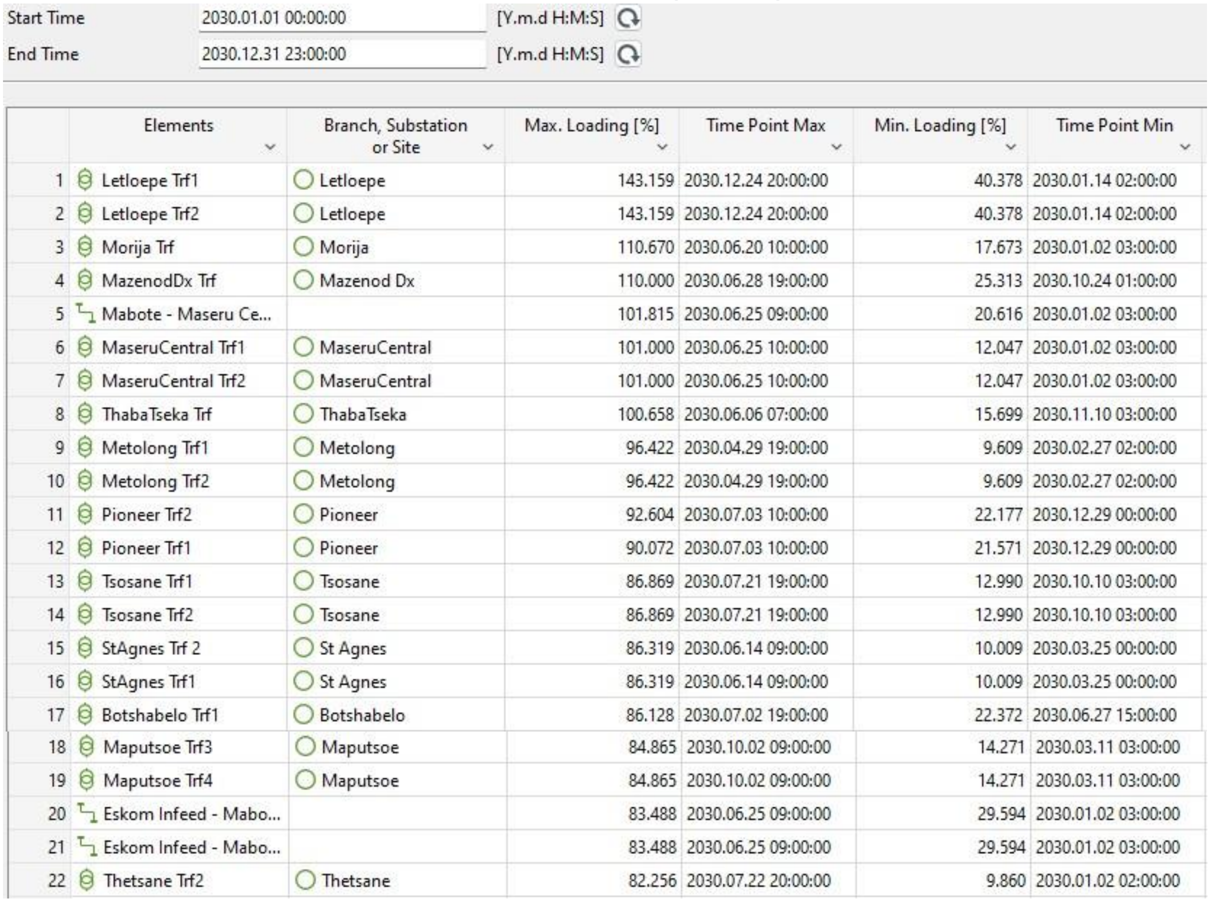


Figure 23: 2030 Schematic diagram with generators off.

4.3.4 Emergency Case Load Flow Analysis for the 2030 Load

A yearly load flow analysis was conducted and no thermal breaches were observed in the network since all line loadings were below 30%. Table 21 displays the thermal loadings that will follow in the absence of any enhancements to the transmission lines or transformers. The 132 kV line from Eskom infeed to Mabote substation will be loaded at 83.49% capacity. This demonstrates that when more electricity is imported, the lines will begin to reach thermal loadings. Compared to Table 19, the Mabote to Maseru Central line would have increased from 90.24 to 101.82%. The transformers at Letloepe would have increased by 15.40%, Maseru Central by 11.47%, Thaba-Tseka by 10.73%, Metolong by 11.35%, and Pioneer by 12.09% and 12.31%. Table 21 indicates that as the load increases, the loading in the network also increases since more power should be imported to meet the demand.

Table 21:2030 thermal loadings with generators off.



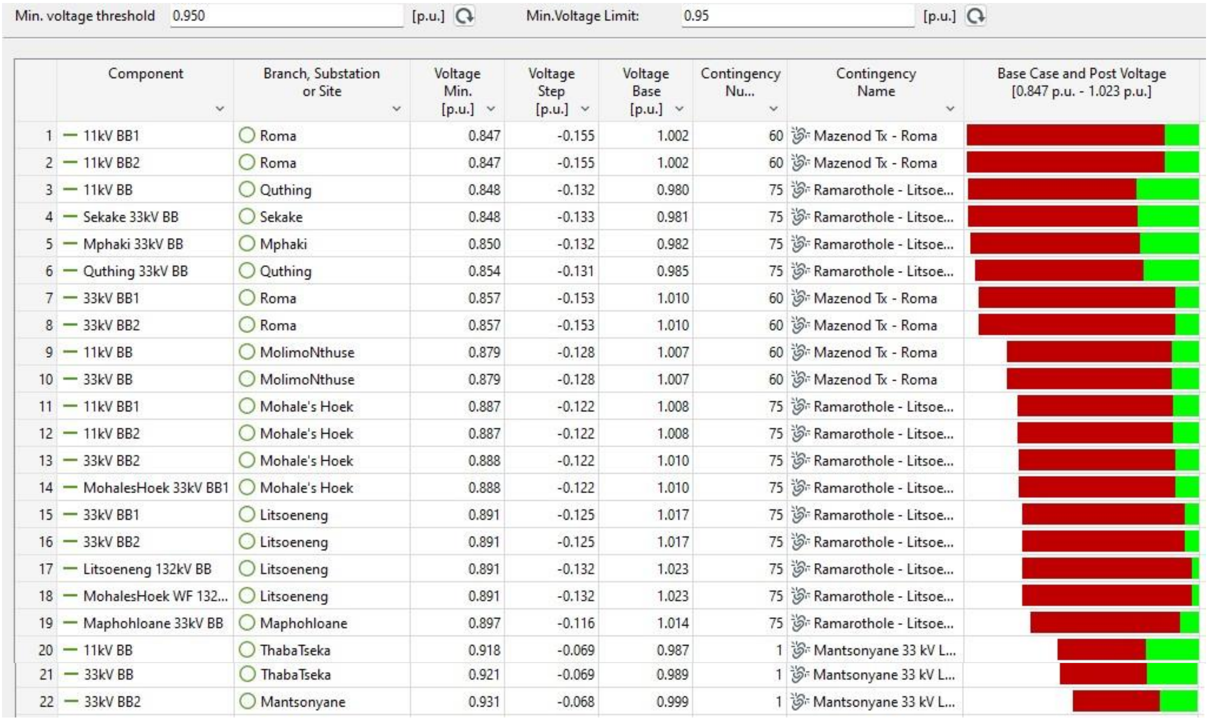
Start Time 2030.01.01 00:00:00 [Y.m.d H:M:S]
End Time 2030.12.31 23:00:00 [Y.m.d H:M:S]

	Elements	Branch, Substation or Site	Max. Loading [%]	Time Point Max	Min. Loading [%]	Time Point Min
1	Letloepe Trf1	Letloepe	143.159	2030.12.24 20:00:00	40.378	2030.01.14 02:00:00
2	Letloepe Trf2	Letloepe	143.159	2030.12.24 20:00:00	40.378	2030.01.14 02:00:00
3	Morija Trf	Morija	110.670	2030.06.20 10:00:00	17.673	2030.01.02 03:00:00
4	MazenodDx Trf	Mazenod Dx	110.000	2030.06.28 19:00:00	25.313	2030.10.24 01:00:00
5	Mabote - Maseru Ce...		101.815	2030.06.25 09:00:00	20.616	2030.01.02 03:00:00
6	MaseruCentral Trf1	MaseruCentral	101.000	2030.06.25 10:00:00	12.047	2030.01.02 03:00:00
7	MaseruCentral Trf2	MaseruCentral	101.000	2030.06.25 10:00:00	12.047	2030.01.02 03:00:00
8	ThabaTseka Trf	ThabaTseka	100.658	2030.06.06 07:00:00	15.699	2030.11.10 03:00:00
9	Metolong Trf1	Metolong	96.422	2030.04.29 19:00:00	9.609	2030.02.27 02:00:00
10	Metolong Trf2	Metolong	96.422	2030.04.29 19:00:00	9.609	2030.02.27 02:00:00
11	Pioneer Trf2	Pioneer	92.604	2030.07.03 10:00:00	22.177	2030.12.29 00:00:00
12	Pioneer Trf1	Pioneer	90.072	2030.07.03 10:00:00	21.571	2030.12.29 00:00:00
13	Tsosane Trf1	Tsosane	86.869	2030.07.21 19:00:00	12.990	2030.10.10 03:00:00
14	Tsosane Trf2	Tsosane	86.869	2030.07.21 19:00:00	12.990	2030.10.10 03:00:00
15	StAgnes Trf 2	St Agnes	86.319	2030.06.14 09:00:00	10.009	2030.03.25 00:00:00
16	StAgnes Trf1	St Agnes	86.319	2030.06.14 09:00:00	10.009	2030.03.25 00:00:00
17	Botshabelo Trf1	Botshabelo	86.128	2030.07.02 19:00:00	22.372	2030.06.27 15:00:00
18	Maputsoe Trf3	Maputsoe	84.865	2030.10.02 09:00:00	14.271	2030.03.11 03:00:00
19	Maputsoe Trf4	Maputsoe	84.865	2030.10.02 09:00:00	14.271	2030.03.11 03:00:00
20	Eskom Infeed - Mabo...		83.488	2030.06.25 09:00:00	29.594	2030.01.02 03:00:00
21	Eskom Infeed - Mabo...		83.488	2030.06.25 09:00:00	29.594	2030.01.02 03:00:00
22	Thetsane Trf2	Thetsane	82.256	2030.07.22 20:00:00	9.860	2030.01.02 02:00:00

4.3.5 Emergency Case Contingency Analysis with Voltage Results for the 2035 Load

The contingency analysis was simulated for 2035 with generators off and there were no contingency elements with loadings above 80% and no terminals with voltage above 1.05 p.u. However, Table 22 shows the elements that violated the minimum voltage requirements of 0.9 and 0.95 p.u. The busbar with the lowest voltage in Table 22 is the 11 kV busbar at Roma operating with 0.847 p.u when the line from Mazenod Tx to Roma experiences an outage and when it is operating there will be a -0.155 p.u to 1.02 p.u at the base case. Compared to Table 15, the busbars with violations below the emergency conditions further decrease. For example, the voltage at the 33 kV busbar at Sekake decreased from 0.856 to 0.848 p.u when the line Ramarothole to Litsoeneng experienced an outage. When the line from Ramarothole to Ha Mofoka experiences an outage, the 11 kV busbar at Mohale's Hoek substation will be operating below the emergency conditions with 0.887 p.u and when it is operating, there will be a -0.122 p.u voltage step up to 1.008 p.u at the base case. The increased number of busbars operating below emergency conditions has to be considered and upgraded to cater for the smooth power flow in the network. Figure 24 shows the schematic results of the simulation. The diagram shows that most of the substations will operate within the bounds of acceptable voltages. However, 10 substations will be operating below 0.95 p.u voltage, and 8 of them operating below emergency conditions which could be critical for the substations if it is not improved.

Table 22: Voltage violations below 0.95 p.u. for 2035 when generators are off



Min. voltage threshold 0.950 [p.u.]

Min.Voltage Limit: 0.95 [p.u.]

	Component	Branch, Substation or Site	Voltage Min. [p.u.]	Voltage Step [p.u.]	Voltage Base [p.u.]	Contingency Nu...	Contingency Name	Base Case and Post Voltage [0.847 p.u. - 1.023 p.u.]
1	11kV BB1	Roma	0.847	-0.155	1.002	60	Mazenod Tx - Roma	
2	11kV BB2	Roma	0.847	-0.155	1.002	60	Mazenod Tx - Roma	
3	11kV BB	Quthing	0.848	-0.132	0.980	75	Ramarothole - Litsoe...	
4	Sekake 33kV BB	Sekake	0.848	-0.133	0.981	75	Ramarothole - Litsoe...	
5	Mphaki 33kV BB	Mphaki	0.850	-0.132	0.982	75	Ramarothole - Litsoe...	
6	Quthing 33kV BB	Quthing	0.854	-0.131	0.985	75	Ramarothole - Litsoe...	
7	33kV BB1	Roma	0.857	-0.153	1.010	60	Mazenod Tx - Roma	
8	33kV BB2	Roma	0.857	-0.153	1.010	60	Mazenod Tx - Roma	
9	11kV BB	MolimoNthuse	0.879	-0.128	1.007	60	Mazenod Tx - Roma	
10	33kV BB	MolimoNthuse	0.879	-0.128	1.007	60	Mazenod Tx - Roma	
11	11kV BB1	Mohale's Hoek	0.887	-0.122	1.008	75	Ramarothole - Litsoe...	
12	11kV BB2	Mohale's Hoek	0.887	-0.122	1.008	75	Ramarothole - Litsoe...	
13	33kV BB2	Mohale's Hoek	0.888	-0.122	1.010	75	Ramarothole - Litsoe...	
14	MohalesHoek 33kV BB1	Mohale's Hoek	0.888	-0.122	1.010	75	Ramarothole - Litsoe...	
15	33kV BB1	Litsoeneng	0.891	-0.125	1.017	75	Ramarothole - Litsoe...	
16	33kV BB2	Litsoeneng	0.891	-0.125	1.017	75	Ramarothole - Litsoe...	
17	Litsoeneng 132kV BB	Litsoeneng	0.891	-0.132	1.023	75	Ramarothole - Litsoe...	
18	MohalesHoek WF 132...	Litsoeneng	0.891	-0.132	1.023	75	Ramarothole - Litsoe...	
19	Maphohloane 33kV BB	Maphohloane	0.897	-0.116	1.014	75	Ramarothole - Litsoe...	
20	11kV BB	ThabaTseka	0.918	-0.069	0.987	1	Mantsonyane 33 kV L...	
21	33kV BB	ThabaTseka	0.921	-0.069	0.989	1	Mantsonyane 33 kV L...	
22	33kV BB2	Mantsonyane	0.931	-0.068	0.999	1	Mantsonyane 33 kV L...	

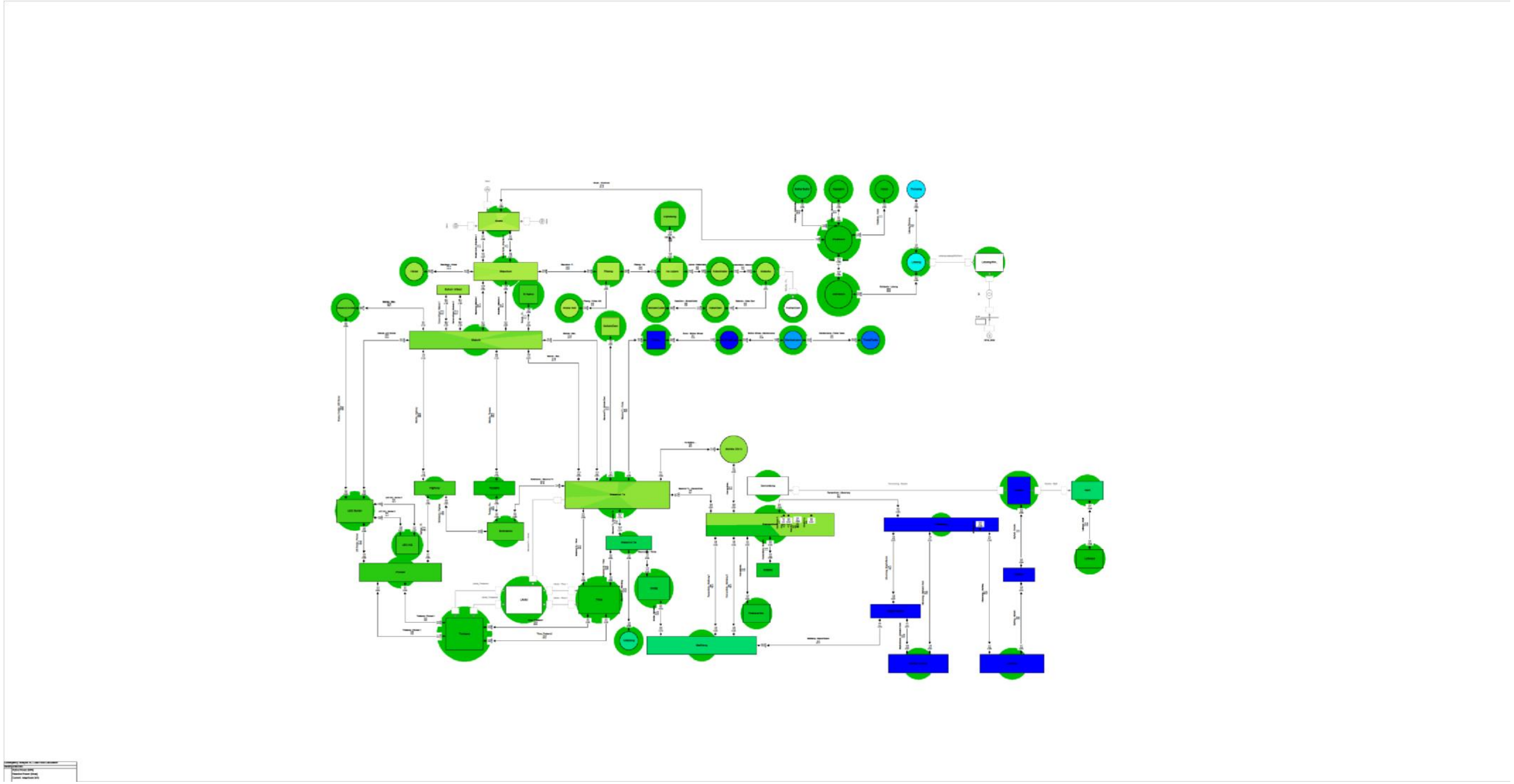
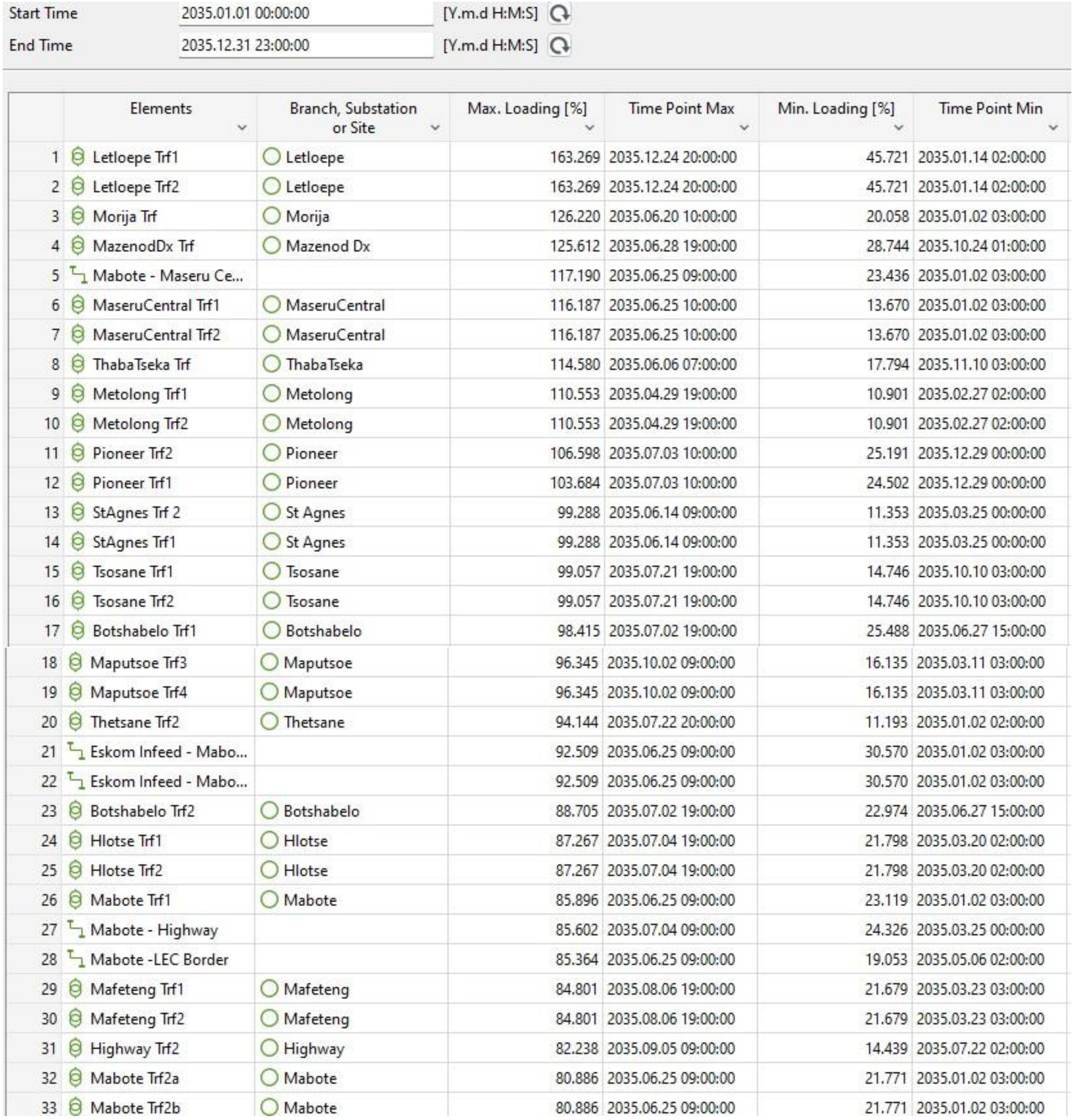


Figure 24: 2035 schematic diagram with generators off.

4.3.6 Emergency Case Load Flow Analysis for the 2035 Load

A yearly load flow analysis was conducted and no cases of thermal breaches were found in the network as all the line loadings stayed below 40%. Table 23 depicts the thermal loadings that would arise in the absence of any enhancements to the transmission lines or transformers. The line from Mabote to Maseru Central would have experienced a 30.51% rise, rising from 91.67% to 117.19%. The 33 kV transmission line from Mabote to the LEC Border will experience a load of 85.36%. The 33 kV transmission line between Mabote and Highway will operate at 85.60% of its maximum capacity. These are the lines that receive more power from the Eskom Infeed at a time of high demand. This is why they should be improved by adding another line to ease the pressure on the existing lines. The 132 kV Eskom infeed line to Mabote exceeds 80% capacity and reaches 92.51%, which coincides with the day of highest electricity demand. To meet the demand in 2035, the rate Eskom Infeed will have to inject more power to the grid. This shows that the lines should have an additional line to support the existing lines. Compared to Table 19, Letloepe's transformer loadings would have increased by 27.79% (from 127.76% to 163.27%), indicating a 28.43% rise at Mazenod Dx (from 98.03% to 125.61%) and a 29.89% rise at Maseru Central (from 89.68% to 116.19%). By examining Table 23, it is evident that in 2035 there will be a higher occurrence of lines and transformers that exceed their capacity during the load flow operations when the country relies on electricity imports.

Table 23: 2035 thermal loadings with generators off.



Start Time 2035.01.01 00:00:00 [Y.m.d H:M:S]
End Time 2035.12.31 23:00:00 [Y.m.d H:M:S]

	Elements	Branch, Substation or Site	Max. Loading [%]	Time Point Max	Min. Loading [%]	Time Point Min
1	Letloepe Trf1	○ Letloepe	163.269	2035.12.24 20:00:00	45.721	2035.01.14 02:00:00
2	Letloepe Trf2	○ Letloepe	163.269	2035.12.24 20:00:00	45.721	2035.01.14 02:00:00
3	Morija Trf	○ Morija	126.220	2035.06.20 10:00:00	20.058	2035.01.02 03:00:00
4	MazenodDx Trf	○ Mazenod Dx	125.612	2035.06.28 19:00:00	28.744	2035.10.24 01:00:00
5	Mabote - Maseru Ce...		117.190	2035.06.25 09:00:00	23.436	2035.01.02 03:00:00
6	MaseruCentral Trf1	○ MaseruCentral	116.187	2035.06.25 10:00:00	13.670	2035.01.02 03:00:00
7	MaseruCentral Trf2	○ MaseruCentral	116.187	2035.06.25 10:00:00	13.670	2035.01.02 03:00:00
8	ThabaTseka Trf	○ ThabaTseka	114.580	2035.06.06 07:00:00	17.794	2035.11.10 03:00:00
9	Metolong Trf1	○ Metolong	110.553	2035.04.29 19:00:00	10.901	2035.02.27 02:00:00
10	Metolong Trf2	○ Metolong	110.553	2035.04.29 19:00:00	10.901	2035.02.27 02:00:00
11	Pioneer Trf2	○ Pioneer	106.598	2035.07.03 10:00:00	25.191	2035.12.29 00:00:00
12	Pioneer Trf1	○ Pioneer	103.684	2035.07.03 10:00:00	24.502	2035.12.29 00:00:00
13	StAgnes Trf 2	○ St Agnes	99.288	2035.06.14 09:00:00	11.353	2035.03.25 00:00:00
14	StAgnes Trf1	○ St Agnes	99.288	2035.06.14 09:00:00	11.353	2035.03.25 00:00:00
15	Tsosane Trf1	○ Tsosane	99.057	2035.07.21 19:00:00	14.746	2035.10.10 03:00:00
16	Tsosane Trf2	○ Tsosane	99.057	2035.07.21 19:00:00	14.746	2035.10.10 03:00:00
17	Botshabelo Trf1	○ Botshabelo	98.415	2035.07.02 19:00:00	25.488	2035.06.27 15:00:00
18	Maputsoe Trf3	○ Maputsoe	96.345	2035.10.02 09:00:00	16.135	2035.03.11 03:00:00
19	Maputsoe Trf4	○ Maputsoe	96.345	2035.10.02 09:00:00	16.135	2035.03.11 03:00:00
20	Thetsane Trf2	○ Thetsane	94.144	2035.07.22 20:00:00	11.193	2035.01.02 02:00:00
21	Eskom Infeed - Mabo...		92.509	2035.06.25 09:00:00	30.570	2035.01.02 03:00:00
22	Eskom Infeed - Mabo...		92.509	2035.06.25 09:00:00	30.570	2035.01.02 03:00:00
23	Botshabelo Trf2	○ Botshabelo	88.705	2035.07.02 19:00:00	22.974	2035.06.27 15:00:00
24	Hlotse Trf1	○ Hlotse	87.267	2035.07.04 19:00:00	21.798	2035.03.20 02:00:00
25	Hlotse Trf2	○ Hlotse	87.267	2035.07.04 19:00:00	21.798	2035.03.20 02:00:00
26	Mabote Trf1	○ Mabote	85.896	2035.06.25 09:00:00	23.119	2035.01.02 03:00:00
27	Mabote - Highway		85.602	2035.07.04 09:00:00	24.326	2035.03.25 00:00:00
28	Mabote -LEC Border		85.364	2035.06.25 09:00:00	19.053	2035.05.06 02:00:00
29	Mafeteng Trf1	○ Mafeteng	84.801	2035.08.06 19:00:00	21.679	2035.03.23 03:00:00
30	Mafeteng Trf2	○ Mafeteng	84.801	2035.08.06 19:00:00	21.679	2035.03.23 03:00:00
31	Highway Trf2	○ Highway	82.238	2035.09.05 09:00:00	14.439	2035.07.22 02:00:00
32	Mabote Trf2a	○ Mabote	80.886	2035.06.25 09:00:00	21.771	2035.01.02 03:00:00
33	Mabote Trf2b	○ Mabote	80.886	2035.06.25 09:00:00	21.771	2035.01.02 03:00:00

4.4 Development Case Criteria Evaluation

This section presents the simulation results for network variations and component loadings, considering the base case generators with an additional 50 MW Ramarothole solar PV and 20 MW OnePower solar PV for 2030. The 2035 scenario includes all the generators in 2030 with additional Hirundo wind farms with 39.6 MW integrated at Mohale’s Hoek and 26.4 MW at Masite Nek substations. Table 24 displays the results of non-compliant substations and busbars throughout the simulation, with voltage limitations set between 0.9 and 1.1 p.u and component loadings set to 80 and 100%. The detailed analysis demonstrating the breached compliance conditions are presented in Table 25, Table 26, Table 27, Table 28, Table 29 and Table 30 for the development case scenario.

Table 24: Development criteria evaluation.

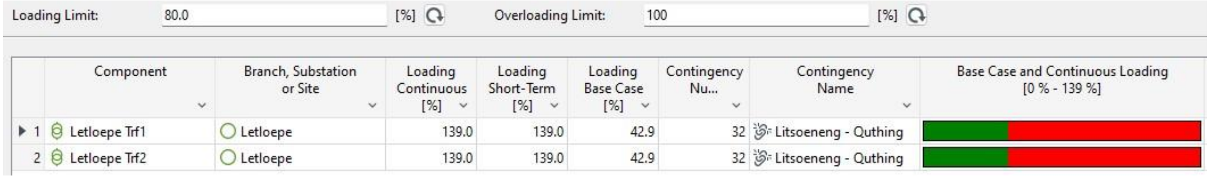
Development Case Simulation	**Compliance Conditions**	**Non-Compliant Substations**	
		2030	**2035**
		< 0.9 p.u or < 0.95 p.u	
Voltage Violations(Busbars)	0.9 p.u-1.1 p.u	Quthing	Quthing
		Mphaki	Mphaki
		Sekake	Sekake
		Mpiti	Mpiti
		Roma	Roma
		Molimo Nthuse	Molimo Nthuse
		Thaba Tseka	Thaba Tseka
		Mohale's Hoek	Mantsonyane
Component Loading(Transmission lines/transformers)	≤ 80%	**> 80%**	
		Letloepe	Mazenod Dx
		Mazenod Dx	Morija
		Morija	Letloepe
		Maseru Central	Maseru Central
		Thaba Tseka	Thaba Tseka
		Mabote to Maseru Central	Mabote to Maseru Central
		Metolong	Metolong
		Pioneer	Pioneer
		Tsosane	St Agnes
		St Agnes	Tsosane
		Botshabelo	Botshabelo
		Maputsoe	Maputsoe
		Thetsane	Thetsane
			Hlotse
			Mazenod Tx to Tikoe
			Mazenod Dx to Tikoe
			Mafeteng
			Highway

			Botshabelo to Mazenod Tx
			Mabote to LCE Border
			Mabote

4.4.1 Development Case Contingency Analysis with Voltage Results for the 2030

The contingency analysis was simulated for the 2030 load and there was only one element with loading above 80 and no terminals with voltage levels above 1.1 p.u. This shows that the generated power in the country will be 174.6 MW after including 20 MW One Power solar PV and 50 MW Ramarothole solar PV to the network. The 1.6 MVA transformers at Letloepe will experience continuous loading of 139.0% when the line from Litsoeneng to Quthing experiences an outage, and the transformer will be operating with 46.2% at the base case when the line is operating, as indicated in Table 25. This shows that the line will then transfer more power than it is anticipated and it should be improved.

Table 25: N-1 Contingency analysis for 2030.

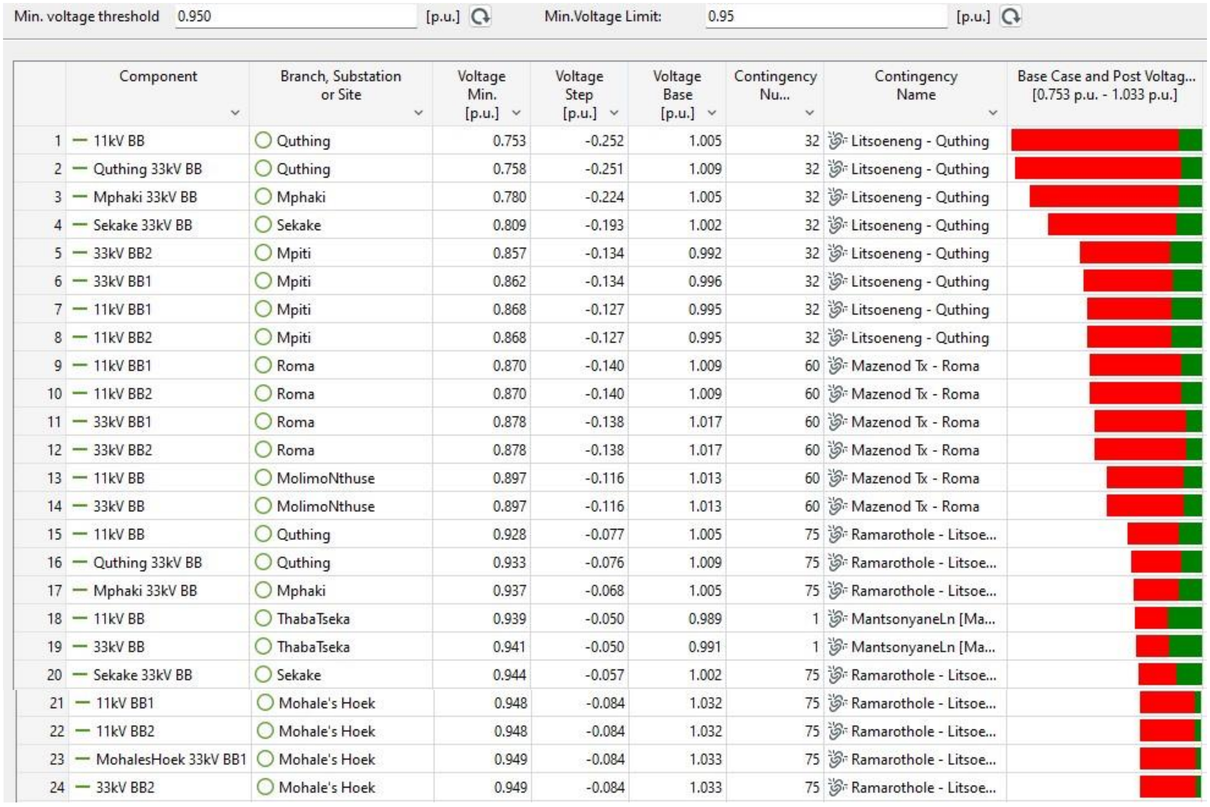


Loading Limit: 80.0 [%]   Overloading Limit: 100 [%]

	Component	Branch, Substation or Site	Loading Continuous [%]	Loading Short-Term [%]	Loading Base Case [%]	Contingency Nu...	Contingency Name	Base Case and Continuous Loading [0 % - 139 %]
1	Letloepe Trf1	○ Letloepe	139.0	139.0	42.9	32	Litsoeneng - Quthing	🟩🟥🟥
2	Letloepe Trf2	○ Letloepe	139.0	139.0	42.9	32	Litsoeneng - Quthing	🟩🟥🟥

Table 26 shows the elements that did not meet the minimum voltage requirement of 0.95 p.u. This indicates the potential under voltage issues. The lowest voltage recorded in the network is at the 11 kV busbar at Quthing with 0.753 p.u when the line from Litsoeneng to Quthing experiences an outage, and when it is operating, there will be a -0.252 p.u voltage step up to 1.005 p.u at the base case. When the line from Mazenod Tx to Roma experiences an outage, the 33 kV busbar at Molimo Nthuse will be operating below the acceptable limit with 0.897 p.u and when it is operating there will be a -0.116 p.u voltage step-up to 1.013 p.u at the base case. Table 26 shows more improvement in the network busbars compared to the emergency and base case scenarios when more power is injected into the network. Figure 25 provides a schematic diagram illustrating the simulation results. Most of the substations operate within normal voltage ranges, but six are in emergency conditions due to voltage violations. The network generally maintains stable voltage levels. However, specific areas, particularly Sekake, Quthing, and four other substations require attention to address voltage violations and to ensure reliable operation.

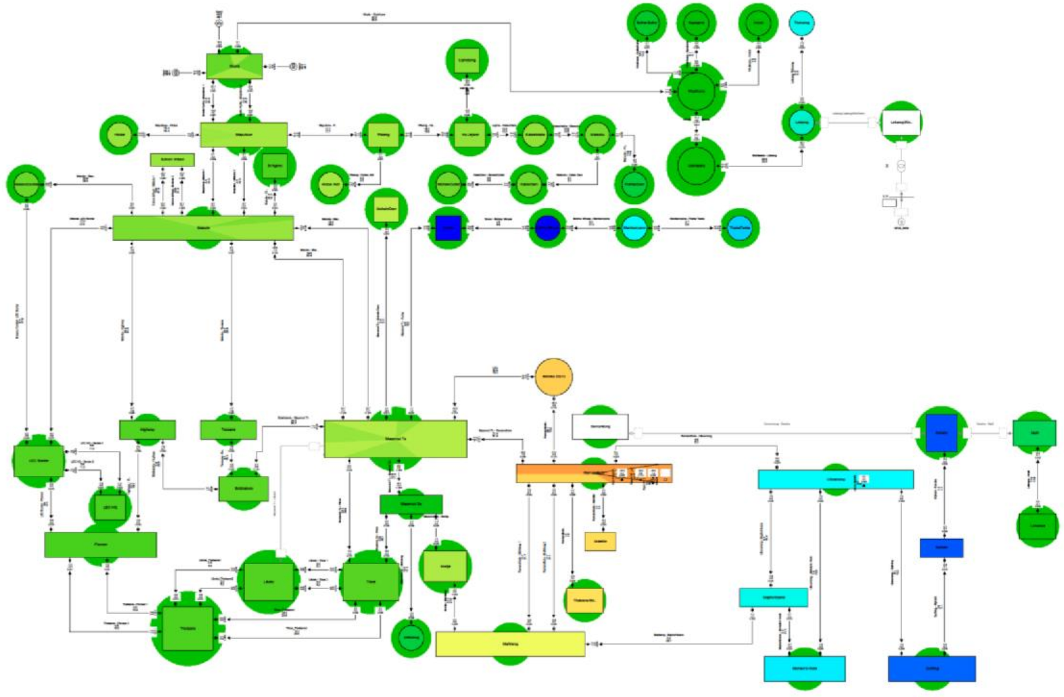
Table 26: Voltage violations below 0.95 p.u, with 70 MW PV included in 2030.



Min. voltage threshold 0.950 [p.u.]

Min.Voltage Limit: 0.95 [p.u.]

	Component	Branch, Substation or Site	Voltage Min. [p.u.]	Voltage Step [p.u.]	Voltage Base [p.u.]	Contingency Nu...	Contingency Name	Base Case and Post Voltag... [0.753 p.u. - 1.033 p.u.]
1	11kV BB	Quthing	0.753	-0.252	1.005	32	Litsoeneng - Quthing	
2	Quthing 33kV BB	Quthing	0.758	-0.251	1.009	32	Litsoeneng - Quthing	
3	Mphaki 33kV BB	Mphaki	0.780	-0.224	1.005	32	Litsoeneng - Quthing	
4	Sekake 33kV BB	Sekake	0.809	-0.193	1.002	32	Litsoeneng - Quthing	
5	33kV BB2	Mpiti	0.857	-0.134	0.992	32	Litsoeneng - Quthing	
6	33kV BB1	Mpiti	0.862	-0.134	0.996	32	Litsoeneng - Quthing	
7	11kV BB1	Mpiti	0.868	-0.127	0.995	32	Litsoeneng - Quthing	
8	11kV BB2	Mpiti	0.868	-0.127	0.995	32	Litsoeneng - Quthing	
9	11kV BB1	Roma	0.870	-0.140	1.009	60	Mazenod Tx - Roma	
10	11kV BB2	Roma	0.870	-0.140	1.009	60	Mazenod Tx - Roma	
11	33kV BB1	Roma	0.878	-0.138	1.017	60	Mazenod Tx - Roma	
12	33kV BB2	Roma	0.878	-0.138	1.017	60	Mazenod Tx - Roma	
13	11kV BB	MolimoNthuse	0.897	-0.116	1.013	60	Mazenod Tx - Roma	
14	33kV BB	MolimoNthuse	0.897	-0.116	1.013	60	Mazenod Tx - Roma	
15	11kV BB	Quthing	0.928	-0.077	1.005	75	Ramarothole - Litsoe...	
16	Quthing 33kV BB	Quthing	0.933	-0.076	1.009	75	Ramarothole - Litsoe...	
17	Mphaki 33kV BB	Mphaki	0.937	-0.068	1.005	75	Ramarothole - Litsoe...	
18	11kV BB	ThabaTseka	0.939	-0.050	0.989	1	MantsonyaneLn [Ma...	
19	33kV BB	ThabaTseka	0.941	-0.050	0.991	1	MantsonyaneLn [Ma...	
20	Sekake 33kV BB	Sekake	0.944	-0.057	1.002	75	Ramarothole - Litsoe...	
21	11kV BB1	Mohale's Hoek	0.948	-0.084	1.032	75	Ramarothole - Litsoe...	
22	11kV BB2	Mohale's Hoek	0.948	-0.084	1.032	75	Ramarothole - Litsoe...	
23	MohalesHoek 33kV BB1	Mohale's Hoek	0.949	-0.084	1.033	75	Ramarothole - Litsoe...	
24	33kV BB2	Mohale's Hoek	0.949	-0.084	1.033	75	Ramarothole - Litsoe...	



Active Power [MW]
Reactive Power [Mvar]
Current, Magnitude [kA]

Figure 25: Schematic diagram for 2030 with 70 MW solar PV included at Ramarothole.

4.4.2 Development Case Load Flow Analysis for the 2030 Load

The yearly load flow analysis was performed, and no thermal loadings were detected. However, the simulation of the load flow indicates that the Eskom Infeed receives power as indicated in Figure 26. This means that in 2030 if the reinforcements are made and the solar plants are operational, Lesotho will start exporting electricity to South Africa. Table 27 displays the highest loadings that occur at specific times and days in the network. According to the data in Table 27, the Letloepe transformers will be subjected to a maximum load of 118.30%. The Mazenod DX transformer will be subjected to a load of 109.44%. The Mabote to Maseru Central line will have an overload of 97.93%, and this shows a reduction in loading compared to the base and emergency cases. However, this line should be upgraded to avoid further loadings. The transformers in Maseru Central will be subjected to a loading of 100.69%. The transformers at Maputsoe substation will reach a loading of 84.64%. Thetsane transformer will be subjected to a load of 81.92%. If there are no improvements on the network, there will be more loadings which might cause problems with the power flow.

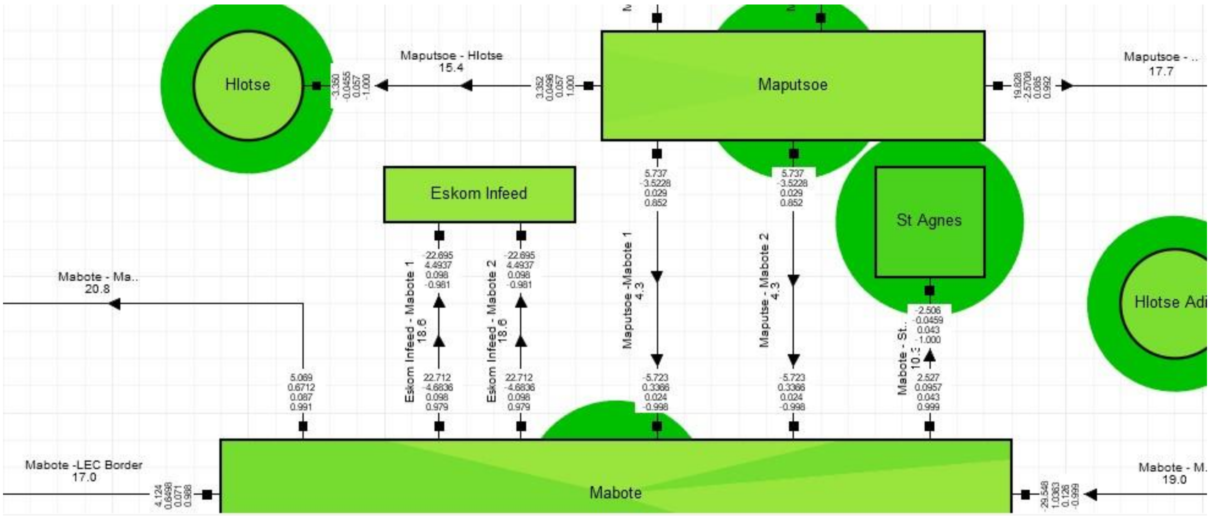
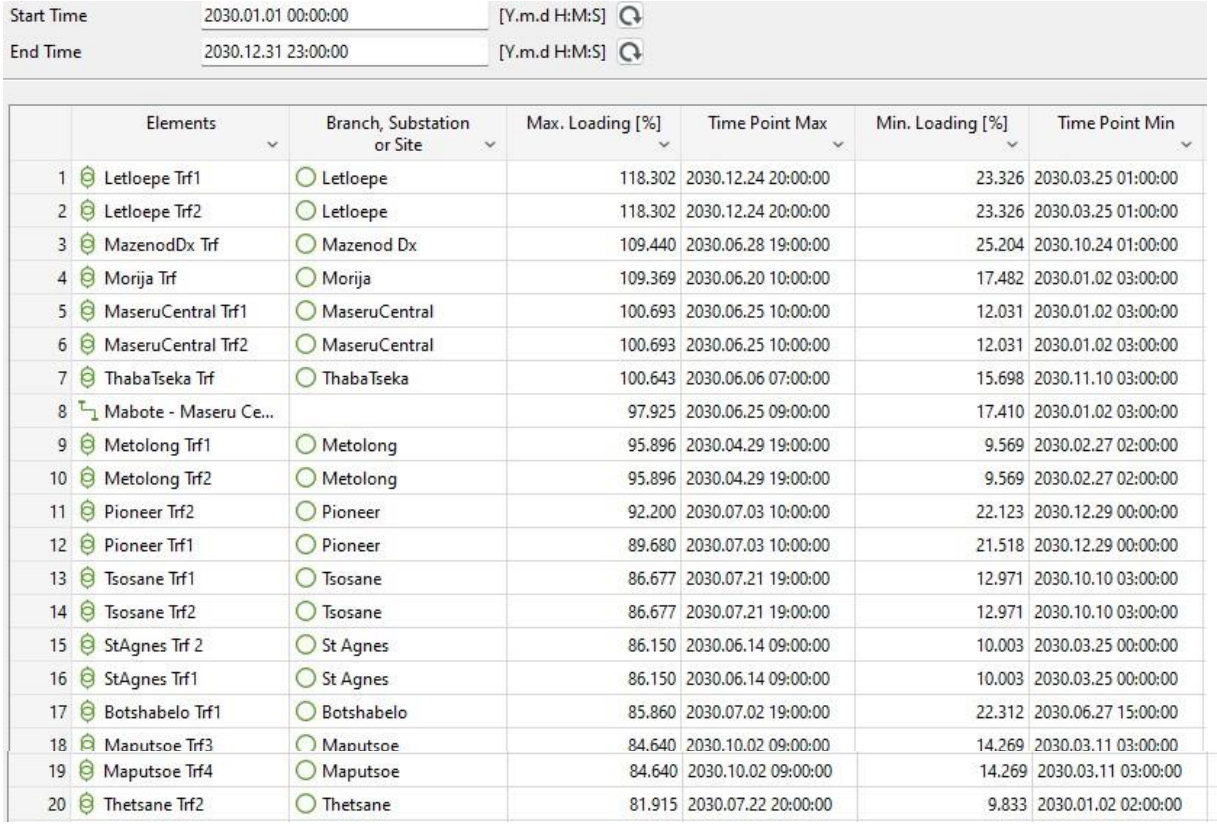


Figure 26: Graphical presentation of the 2030 load flow analysis.

Table 27: Thermal loadings with Ramarothole, 'Muela and OnePower in 2030.



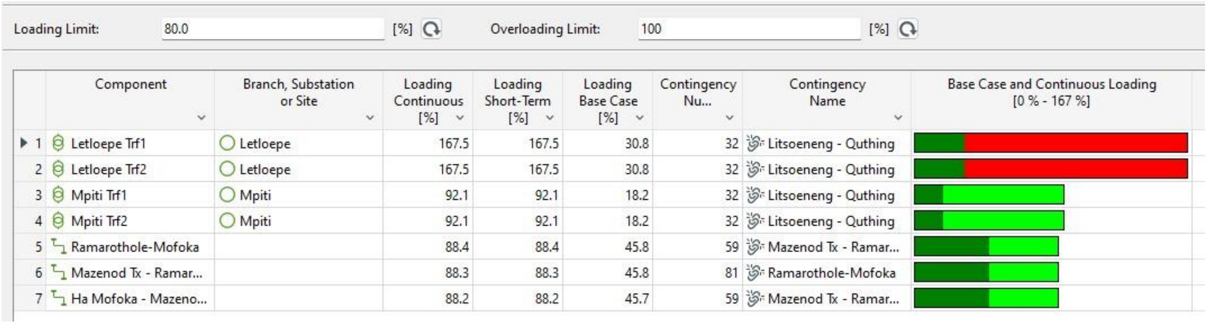
Start Time 2030.01.01 00:00:00 [Y.m.d H:M:S]
End Time 2030.12.31 23:00:00 [Y.m.d H:M:S]

	Elements	Branch, Substation or Site	Max. Loading [%]	Time Point Max	Min. Loading [%]	Time Point Min
1	Letloepe Trf1	Letloepe	118.302	2030.12.24 20:00:00	23.326	2030.03.25 01:00:00
2	Letloepe Trf2	Letloepe	118.302	2030.12.24 20:00:00	23.326	2030.03.25 01:00:00
3	MazenodDx Trf	Mazenod Dx	109.440	2030.06.28 19:00:00	25.204	2030.10.24 01:00:00
4	Morija Trf	Morija	109.369	2030.06.20 10:00:00	17.482	2030.01.02 03:00:00
5	MaseruCentral Trf1	MaseruCentral	100.693	2030.06.25 10:00:00	12.031	2030.01.02 03:00:00
6	MaseruCentral Trf2	MaseruCentral	100.693	2030.06.25 10:00:00	12.031	2030.01.02 03:00:00
7	ThabaTseka Trf	ThabaTseka	100.643	2030.06.06 07:00:00	15.698	2030.11.10 03:00:00
8	Mabote - Maseru Ce...		97.925	2030.06.25 09:00:00	17.410	2030.01.02 03:00:00
9	Metolong Trf1	Metolong	95.896	2030.04.29 19:00:00	9.569	2030.02.27 02:00:00
10	Metolong Trf2	Metolong	95.896	2030.04.29 19:00:00	9.569	2030.02.27 02:00:00
11	Pioneer Trf2	Pioneer	92.200	2030.07.03 10:00:00	22.123	2030.12.29 00:00:00
12	Pioneer Trf1	Pioneer	89.680	2030.07.03 10:00:00	21.518	2030.12.29 00:00:00
13	Tsosane Trf1	Tsosane	86.677	2030.07.21 19:00:00	12.971	2030.10.10 03:00:00
14	Tsosane Trf2	Tsosane	86.677	2030.07.21 19:00:00	12.971	2030.10.10 03:00:00
15	StAgnes Trf 2	St Agnes	86.150	2030.06.14 09:00:00	10.003	2030.03.25 00:00:00
16	StAgnes Trf1	St Agnes	86.150	2030.06.14 09:00:00	10.003	2030.03.25 00:00:00
17	Botshabelo Trf1	Botshabelo	85.860	2030.07.02 19:00:00	22.312	2030.06.27 15:00:00
18	Maputsoe Trf3	Maputsoe	84.640	2030.10.02 09:00:00	14.269	2030.03.11 03:00:00
19	Maputsoe Trf4	Maputsoe	84.640	2030.10.02 09:00:00	14.269	2030.03.11 03:00:00
20	Thetsane Trf2	Thetsane	81.915	2030.07.22 20:00:00	9.833	2030.01.02 02:00:00

4.4.3 Development Case Contingency Analysis with Voltage Results for the 2035

The N-1 contingency analysis was conducted to assess the most severe violations that may arise following the integration of 26.4 MW and 39.6 MW Hirundo wind farms to the network, as well as the expansion of the Ramarothole Solar PV to 80 MW and the addition of a 20 MW One Power solar PV. This shows that the generation in the country will be 240.6 MW. The findings presented in Table 28 shows that the loadings on the transformers at Letloepe will reach a continuous loading of 167.5% when the line from Litsoeneng to Quthing experiences an outage and 40.4% at the base case when the line is operating. When the line from Mazenod to Ramarothole experiences an outage, the line to the switching station at Ha Mofoka will experience a continuous loading of 88.4% and when it is operating the line will operate at 45.8 % at the base case. This is due to more power injected into the network and there is a need to export since more power will be from the Ramarothole substation.

Table 28: N-1 Contingency analysis for 2035.

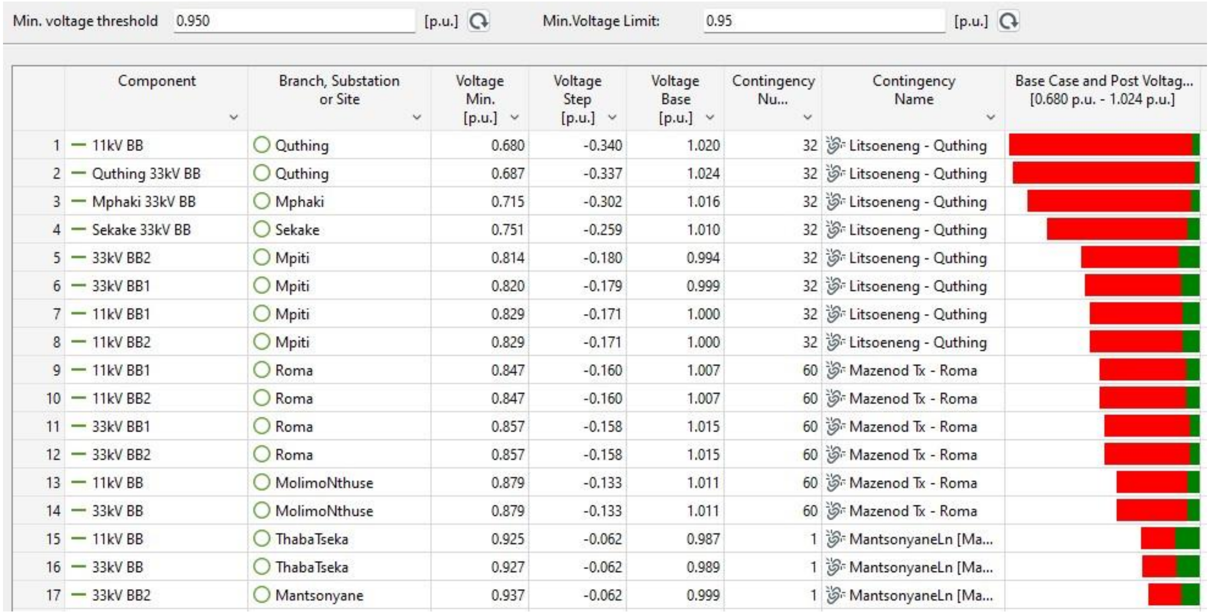


Loading Limit: 80.0 [%]
Overloading Limit: 100 [%]

	Component	Branch, Substation or Site	Loading Continuous [%]	Loading Short-Term [%]	Loading Base Case [%]	Contingency Nu...	Contingency Name	Base Case and Continuous Loading [0 % - 167 %]
1	Letloepe Trf1	Letloepe	167.5	167.5	30.8	32	Litsoeneng - Quthing	
2	Letloepe Trf2	Letloepe	167.5	167.5	30.8	32	Litsoeneng - Quthing	
3	Mpiti Trf1	Mpiti	92.1	92.1	18.2	32	Litsoeneng - Quthing	
4	Mpiti Trf2	Mpiti	92.1	92.1	18.2	32	Litsoeneng - Quthing	
5	Ramarothole-Mofoka		88.4	88.4	45.8	59	Mazenod Tx - Ramar...	
6	Mazenod Tx - Ramar...		88.3	88.3	45.8	81	Ramarothole-Mofoka	
7	Ha Mofoka - Mazeno...		88.2	88.2	45.7	59	Mazenod Tx - Ramar...	

There were no contingency terminals with voltage levels above 1.1 p.u. However, Table 29 shows the elements that violated the minimum voltage requirements of 0.9 and 0.95 p.u. From Table 29 it can be depicted that when the line from Litsoeneng to Quthing experiences an outage, the 11 kV busbars at Quthing will be operating below the minimum acceptable voltage with a minimum of 0.68 p.u and when it is operating there will be a -0.340 p.u voltage step up to 1.020 p.u at the base case. When the line from Litsoeneng to Quthing experiences an outage, the 33 kV busbar at Mpiti will experience voltages below the acceptable limit with a minimum of 0.814 p.u. and when it is operating there will be a -0.180 p.u voltage step up to 0.994 p.u at the base case. The 11 kV and 33 kV busbars at Molimo Nthuse will be operating with a minimum of 0.879 p.u when the line from Mazenod Tx to Roma experiences an outage and when it is operating normally there will be a -0.133 voltage step up to 1.011 p.u at the base case. When the 33 kV line at the Mants'onyane substation experiences an outage, the 33 kV busbar at Mants'onyane will encounter a minimum of 0.937 p.u and there will be a -0.062 p.u voltage step up to 0.999 p.u when the line operates normally at the base case. Table 29 shows more improvement on the network busbars compared to the emergency and base case scenarios after two wind farms are injected into the network. Figure 27 shows the schematic diagram with the results of the simulation with the red lines showing where most thermal loadings will take place. The diagram shows that only 6 substations will operate with voltages below the allowable voltage condition of 0.9 p.u and should be considered for improvements. However, most substations will be operating at normal conditions.

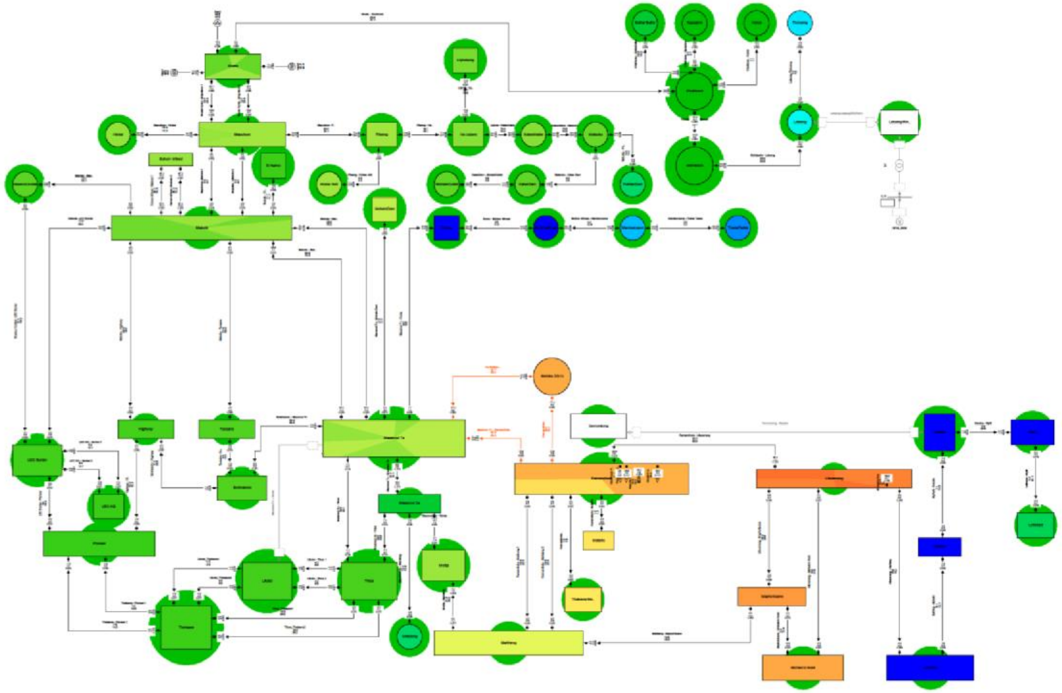
Table 29: Voltage violations below 0.95 p.u. for 2035 with all generators.



Min. voltage threshold 0.950 [p.u.]

Min.Voltage Limit: 0.95 [p.u.]

	Component	Branch, Substation or Site	Voltage Min. [p.u.]	Voltage Step [p.u.]	Voltage Base [p.u.]	Contingency Nu...	Contingency Name	Base Case and Post Voltag... [0.680 p.u. - 1.024 p.u.]
1	11kV BB	Quthing	0.680	-0.340	1.020	32	Litsoeneng - Quthing	
2	Quthing 33kV BB	Quthing	0.687	-0.337	1.024	32	Litsoeneng - Quthing	
3	Mphaki 33kV BB	Mphaki	0.715	-0.302	1.016	32	Litsoeneng - Quthing	
4	Sekake 33kV BB	Sekake	0.751	-0.259	1.010	32	Litsoeneng - Quthing	
5	33kV BB2	Mpiti	0.814	-0.180	0.994	32	Litsoeneng - Quthing	
6	33kV BB1	Mpiti	0.820	-0.179	0.999	32	Litsoeneng - Quthing	
7	11kV BB1	Mpiti	0.829	-0.171	1.000	32	Litsoeneng - Quthing	
8	11kV BB2	Mpiti	0.829	-0.171	1.000	32	Litsoeneng - Quthing	
9	11kV BB1	Roma	0.847	-0.160	1.007	60	Mazenod Tx - Roma	
10	11kV BB2	Roma	0.847	-0.160	1.007	60	Mazenod Tx - Roma	
11	33kV BB1	Roma	0.857	-0.158	1.015	60	Mazenod Tx - Roma	
12	33kV BB2	Roma	0.857	-0.158	1.015	60	Mazenod Tx - Roma	
13	11kV BB	MolimoNthuse	0.879	-0.133	1.011	60	Mazenod Tx - Roma	
14	33kV BB	MolimoNthuse	0.879	-0.133	1.011	60	Mazenod Tx - Roma	
15	11kV BB	ThabaTseka	0.925	-0.062	0.987	1	MantsonyaneLn [Ma...	
16	33kV BB	ThabaTseka	0.927	-0.062	0.989	1	MantsonyaneLn [Ma...	
17	33kV BB2	Mantsonyane	0.937	-0.062	0.999	1	MantsonyaneLn [Ma...	



Contingency Analysis: AC Load Flow Calculation

[illegible]

Active Power [MW]

Reactive Power [Mvar]

Current, Magnitude [kA]

Figure 27: Schematic diagram for 2035 with all generators.

4.4.4 Development Case Load Flow Analysis for the 2035 Load

The yearly load flow was conducted and no thermal loadings above 80% were found. Figure 28 shows the graphical presentation of the yearly load flow with all generators online. From Figure 28, the load flow results show that more power will be exported through the Eskom Infeed. Since more power is only needed during peak demand, this scenario demonstrates that during regular days the power will be exported to South Africa and sold to the SAPP considering dispatching times. Table 30 shows the maximum loadings that occurred in the network when projecting for the 2035 operation scenario with all power generators present. From the follow-up of the simulations, the maximum loadings for certain transformers experience maximum loading at the same time for all the years. The transformer at Mazenod Dx will reach a maximum loading of 124.78%. The transformer at Morija will reach a maximum of 124.01%. The Maseru Central transformers will reach a maximum of 115.76% if not reinforced by 2035. The transformers at Letloepe substations seem to have decreased in loadings, compared to the base case and emergency cases since they will reach 116.42%. This may be caused by the injection of 39.6 MW at the Mohale's Hoek substation. The transmission line from Mabote to Maseru Central will reach 111.14% loading which is lower compared to the 2035 base case and the emergency case scenarios. The indication here is that as more power is injected into the grid, the loadings on the transformers decrease but the number of transmission line thermal loadings increases. The 33 kV line from Mabote to the LEC Border will experience a loading of 79.47%. The 33 kV line from Botshabelo to Mazenod will reach a maximum of 79.72% and will reach the loading if not reinfored.

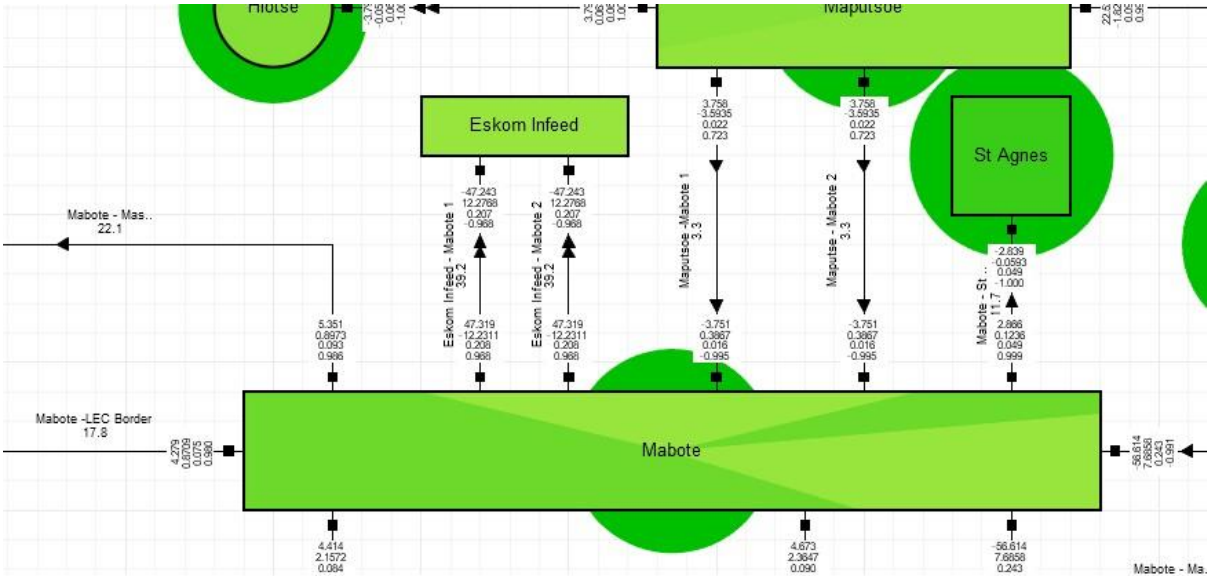
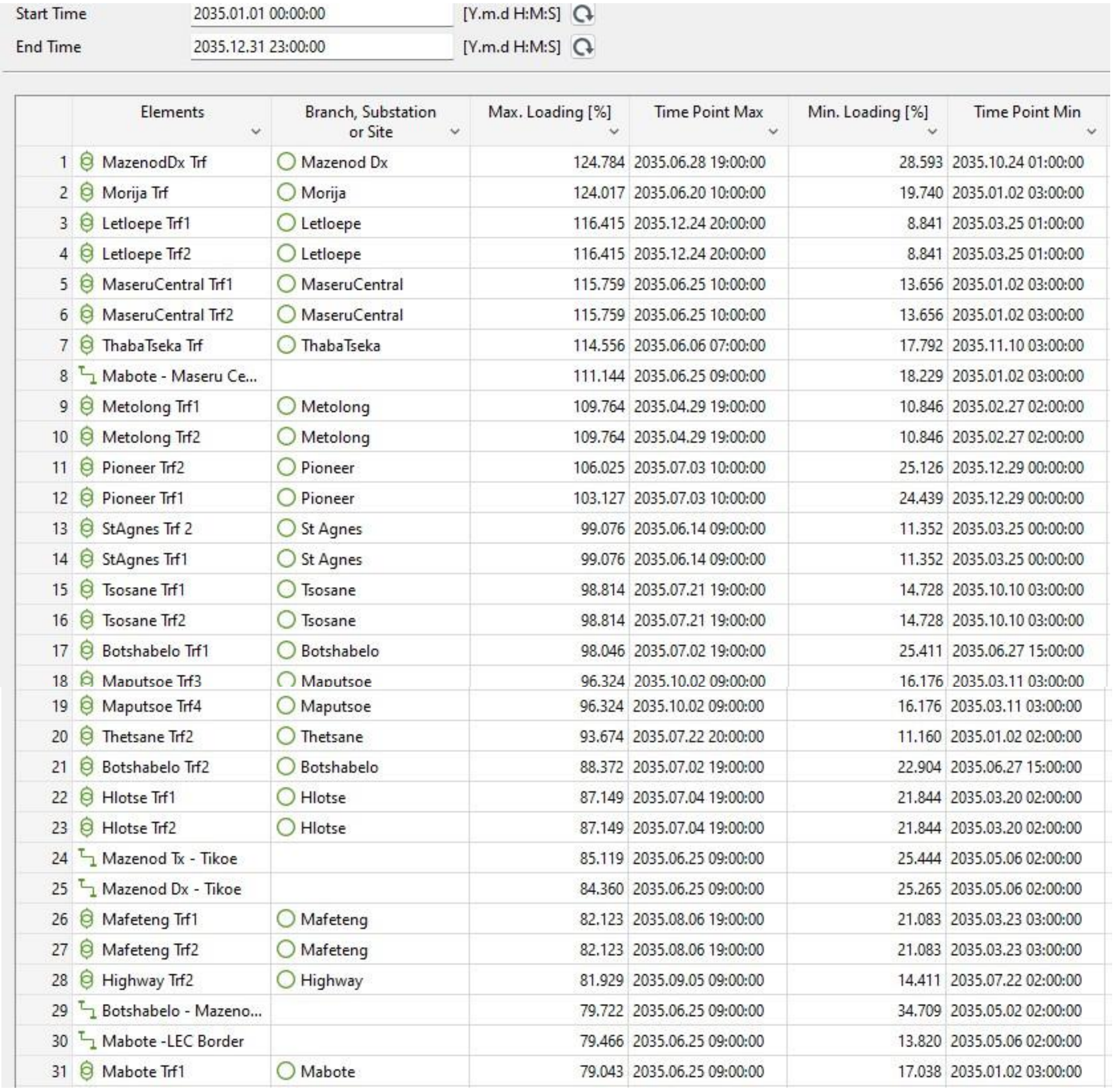


Figure 28: Graphical representation of yearly load flow analysis with all generators.

Table 30: 2035 thermal loadings with all generators.



Start Time 2035.01.01 00:00:00 [Y.m.d H:M:S]
End Time 2035.12.31 23:00:00 [Y.m.d H:M:S]

	Elements	Branch, Substation or Site	Max. Loading [%]	Time Point Max	Min. Loading [%]	Time Point Min
1	MazenodDx Trf	Mazenod Dx	124.784	2035.06.28 19:00:00	28.593	2035.10.24 01:00:00
2	Morija Trf	Morija	124.017	2035.06.20 10:00:00	19.740	2035.01.02 03:00:00
3	Letloepe Trf1	Letloepe	116.415	2035.12.24 20:00:00	8.841	2035.03.25 01:00:00
4	Letloepe Trf2	Letloepe	116.415	2035.12.24 20:00:00	8.841	2035.03.25 01:00:00
5	MaseruCentral Trf1	MaseruCentral	115.759	2035.06.25 10:00:00	13.656	2035.01.02 03:00:00
6	MaseruCentral Trf2	MaseruCentral	115.759	2035.06.25 10:00:00	13.656	2035.01.02 03:00:00
7	ThabaTseka Trf	ThabaTseka	114.556	2035.06.06 07:00:00	17.792	2035.11.10 03:00:00
8	Mabote - Maseru Ce...		111.144	2035.06.25 09:00:00	18.229	2035.01.02 03:00:00
9	Metolong Trf1	Metolong	109.764	2035.04.29 19:00:00	10.846	2035.02.27 02:00:00
10	Metolong Trf2	Metolong	109.764	2035.04.29 19:00:00	10.846	2035.02.27 02:00:00
11	Pioneer Trf2	Pioneer	106.025	2035.07.03 10:00:00	25.126	2035.12.29 00:00:00
12	Pioneer Trf1	Pioneer	103.127	2035.07.03 10:00:00	24.439	2035.12.29 00:00:00
13	StAgnes Trf 2	St Agnes	99.076	2035.06.14 09:00:00	11.352	2035.03.25 00:00:00
14	StAgnes Trf1	St Agnes	99.076	2035.06.14 09:00:00	11.352	2035.03.25 00:00:00
15	Tsosane Trf1	Tsosane	98.814	2035.07.21 19:00:00	14.728	2035.10.10 03:00:00
16	Tsosane Trf2	Tsosane	98.814	2035.07.21 19:00:00	14.728	2035.10.10 03:00:00
17	Botshabelo Trf1	Botshabelo	98.046	2035.07.02 19:00:00	25.411	2035.06.27 15:00:00
18	Maputsoe Trf3	Maputsoe	96.324	2035.10.02 09:00:00	16.176	2035.03.11 03:00:00
19	Maputsoe Trf4	Maputsoe	96.324	2035.10.02 09:00:00	16.176	2035.03.11 03:00:00
20	Thetsane Trf2	Thetsane	93.674	2035.07.22 20:00:00	11.160	2035.01.02 02:00:00
21	Botshabelo Trf2	Botshabelo	88.372	2035.07.02 19:00:00	22.904	2035.06.27 15:00:00
22	Hlotse Trf1	Hlotse	87.149	2035.07.04 19:00:00	21.844	2035.03.20 02:00:00
23	Hlotse Trf2	Hlotse	87.149	2035.07.04 19:00:00	21.844	2035.03.20 02:00:00
24	Mazenod Tx - Tikoe		85.119	2035.06.25 09:00:00	25.444	2035.05.06 02:00:00
25	Mazenod Dx - Tikoe		84.360	2035.06.25 09:00:00	25.265	2035.05.06 02:00:00
26	Mafeteng Trf1	Mafeteng	82.123	2035.08.06 19:00:00	21.083	2035.03.23 03:00:00
27	Mafeteng Trf2	Mafeteng	82.123	2035.08.06 19:00:00	21.083	2035.03.23 03:00:00
28	Highway Trf2	Highway	81.929	2035.09.05 09:00:00	14.411	2035.07.22 02:00:00
29	Botshabelo - Mazeno...		79.722	2035.06.25 09:00:00	34.709	2035.05.02 02:00:00
30	Mabote -LEC Border		79.466	2035.06.25 09:00:00	13.820	2035.05.06 02:00:00
31	Mabote Trf1	Mabote	79.043	2035.06.25 09:00:00	17.038	2035.01.02 03:00:00

4.5 Economic Voltage

According to Equation (6), the economic voltage is determined by two factors: the length of the transmission line and the amount of power being transferred through the transmission line. The economic voltage rises proportionally with the lengthening of the transmission line. As a result, the power that is transported also increases, resulting in a greater economic voltage. The economic voltage calculation results are deemed safe due to the transmission lengths in the network being less than 200 km. Based on the information provided in Table 3, it can be concluded that the 132 kV lines in the Lesotho Network are still considered to be safe.

4.6 Investment in the Reinforcement of the Transmission Lines and Transformers

Table 31 displays the suggested improvements to the transmission lines in order to meet the demand without overloading, along with their corresponding prices in 2030 so that the network can be ready to absorb the power generated in 2035. The Ramarothole substation will require 6 MVAR compensation to control the 132 kV busbar voltage to 1 p.u to assist with outages in the network. The Mazenod Tx substation will need a static var compensator to ensure all the primary busbars voltages are above 0.95 p.u. A new 33 kV line needs to be added to the existing line from Mabote to Maseru Central in order to reinforce it and to create a double circuit. This is necessary in order to accommodate the increased thermal loads. A new 33 kV line expansion is needed from Mabote to Highway in order to create a double circuit that can handle both temperature and voltage loadings. The current 33 kV line from Mabote to the LEC boundary needs to be expanded to accommodate the thermal loads. This can be achieved by either upgrading the line to 66 kV or adding another 33 kV line to create a double circuit. It is necessary to strengthen the existing two 132 kV lines that connect the Eskom infeed to the Mabote substation by adding another 132 kV line. This additional line would provide three circuits to accommodate the imported electricity from South Africa and Mozambique. A new 33 kV line needs to be added to the current line from Mazenod Dx to Morija in order to strengthen it and create a double circuit. The amount located depends on the distance covered by the transmission lines from substation to substation considering their loadings. This is necessary for handling the increased thermal loads. The prices for 2030 and 2035 were calculated using Equation 12 assuming that the inflation rate is 6.38%. The total cost of the transmission line reinforcements was found to be USD 44,803,233.79 in 2030 anticipating the network being ready by 2035 when main generators come online.

Table 32 displays the suggested extra transformer enhancements required to meet the demand without any loadings, along with their corresponding pricing in 2030 anticipating that the main generators from the development case scenario become online. In order to meet future demand, the Letloepe substation will need to add 2 MVA transformers to the existing 1.6 MVA transformers. An extra 5 MVA transformer will be needed at Mazenod Dx to accommodate potential thermal loading in the future, in addition to the existing 5 MVA transformer. An extra 5MVA transformer is needed at Maseru Central to accommodate the potential thermal loading, in addition to the present 10 MVA transformer. An extra 2 MVA transformer is needed at Thaba-Tseka to accommodate potential thermal loading in the coming years, in addition to the present 2 MVA transformer. An additional 5 MVA is needed at Maputsoe substation to accommodate thermal loadings. An extra 5 MVA transformer is needed at Metolong to accommodate potential thermal loading in the coming years, in addition to the present 5 MVA transformer.

Table 31: Investment in transmission line reinforcement in 2030

Transmission Lines ID	Voltage (kV)	Single / Double line	Total Length (km)	Price per km (USD/km)	Total line Cost (USD)
Mabote - Maseru Central	33	1	8	183,243.97	1,465,951.76
Mabote - Highway	33	1	7	183,243.97	1,282,707.79
Mabote -LEC Border	33	1	12	183,243.97	2,198,927.64
Eskom infeed - Mabote	132	1	5.3	238,217.17	1,501,051.00
Mazenod Dx - Morija	33	1	30	183,243.97	5,497,319.1
Mabote – Mazenod Tx1	132	1	18.7	238,217.17	4,454,661.08
Mazenod Tx - Tikoe	33	1	13	183,243.97	2,382,171.61
Botsabelo- Mazenod	33	1	10	183,243.97	1,832,439.70
Mazenod Dx - Tikoe	33	1	13	183,243.97	2,382,171.61
Litsoeneng- Maphohloane	33	1	10	183,243.97	1,832,439.70
Mafeteng -Maphohloane	33	1	60	183,243.97	10,994,638.20
Morija- Mafeteng	33	1	30	183,243.97	5,497,319.10
Litsoeneng-Mohale’s Hoek	33	1	10	183,243.97	1,832,239.70
Letloepe- Mpiti	11	1	10	164,919.58	1,649,195.80
Total					**44,803,233.79**

Furthermore, a 10 MVA transformer is needed at Pioneer to accommodate the potential thermal loadings in the coming years, in addition to the two current 10 MVA transformers 1 and 2. An additional 5 MVA transformers will be needed at Tsosane to accommodate potential thermal loading in the coming years, in addition to the present 5 MVA transformers. An additional 5 MVA transformers will be needed at St. Agnes to accommodate the potential thermal loading in the coming years, in addition to the present 5 MVA transformers. In order to accommodate the potential thermal loading in the coming years, an extra 10 MVA transformers will be needed at Botshabelo, in addition to the present ones. An additional 20 MVA transformers will be needed at Thetsane to accommodate potential thermal loading in the coming years. An extra 5 MVA transformer is needed at Mafeteng to accommodate potential thermal loading in the coming years, in addition to the present 5 MVA transformer. In order to accommodate the thermal loadings and potential future power imports or exports, it is necessary to add four more 40 MVA transformers to the current ones at Mabote. The total cost for the reinforcement of transformers was found to be USD 125,338,880.49 in 2030.

Table 32: 2030 Investment in transformers.

Existing Transformers	**Transformer Additional Size (MVA)**	**No. of Transformers**	**Price per km (USD)**	**Total Transformer Cost (USD)**
Letloepe Trf 1&2 (1.6 MVA)	2	2	732,975.91	1,465,951.82
Mazenod Dx (5 MVA)	5	1	1,832,439.77	1,832,439.77
MaseruCentral Trf 1&2 (10 MVA)	5	2	1,832,439.77	3,664,879.54
ThabaTseka (2 MVA)	2	2	732,975.91	1,465,951.82
Metolong Trf 1&2 (5 MVA)	5	2	1,832,439.77	3,664,879.54
Pioneer Trf 1&2 (10 MVA)	10	2	3,664,879.55	7,329,759.09
St Agnes Trf 1&2 (5 MVA)	5	2	1,832,439.77	3,664,879.54
Tsosane Trf 1&2 (5 MVA)	5	2	1,832,439.77	3,664,879.54
Botsabelo Trf 1&2(10 MVA)	10	2	3,664,879.55	7,329,759.09
Thetsane Trf 2 (20 MVA)	20	1	7,329,759.09	7,329,759.09
Mapustoe Trf 3 &4	10	2	3,664,879.55	7,329,759.09
Mpiti Trf 1 &2	2	2	732,975.91	1,465,951.82
Litsoeneng Trf 1 &2	20	1	7,329,759.09	7,329,759.09
Mafeteng Trf 1&2(5 MVA)	5	2	1,832,439.77	3,664,879.54
Mabote Trf1,2 and 2a,2b (40 MVA)	40	4	14,659,518.20	58,638,072.8
Hlotse Trf1&2 (5 MVA)	5	2	1,832,439.77	3,664,879.54
Highway Trf2 (10 MVA)	5	1	1,832,439.77	1,832,439.77
Total				**125,338,880.49**

5 Conclusions and Recommendations

5.1 Concluding Remarks

The conducted simulations for the base year (2023) and other reference years (2030 and 2035) scenarios reveal critical insights into the LEC network's stability and the necessity for strategic transmission network expansion planning. The introduction of significant variable renewable energy sources, such as the 30 MW Ramarothole solar PV, the 20 MW OnePower solar PV, the upgrade to 80 MW for Ramarothole, and the addition of the 66 MW Hirundo wind farms, were analysed under various operational conditions.

The key findings from the simulations indicate a substantial 30% increase in transformer loadings from the base case to 2030 and a 14% increase from the year to 2035 operational scenario. Both transmission lines and transformers approach the critical 80% loading limit in the year 2030 and 2035 scenarios due to the increased load. The highest transformer loadings are observed in winter (around June), coinciding with peak electricity demand in the country. From the results, it is found that when all the solar generators and wind farms come online, the available energy exceeds the local demand and the country will start to export power to South Africa through the Eskom Infeed, hence certain improvements propositions in the interconnect are made. This is to cater for the proper transfer of power through transmission lines.

The N-1 contingency criterion reveals elements violating the voltage regulations, with some falling below the 0.95 p.u. minimum and others exceeding the 1.05 p.u. maximum. These voltage stability and line loading violations necessitate immediate attention to ensure network reliability. The improvement of transformers and transmission lines will be able to regulate the voltage stability in the network. Cost analyses for reinforcing the transmission infrastructure were conducted, with the upgrade of transmission lines estimated at USD 44,803,233.79 and transformer upgrades at USD 125,338,880.49.

5.2 Recommendations

To meet the increasing power demand and facilitate the integration of renewable energy sources without compromising network stability, it is recommended that LEC invest in new power transformers at various substations and reinforce existing transmission lines. Such strategic enhancements will not only support the growing energy requirements but will also promote the seamless incorporation of renewable energy, ensuring a stable and reliable electricity supply for the future.

In addition to transmission line planning, numerous studies have been carried out on future generation sources utilizing renewable energy. To advance these projects, it is worth examining how the proposed Polihali floating solar PV, Oxbow pumped storage, and Lets'eng wind farms can be seamlessly integrated into the existing network to enhance energy security in the country A thorough assessment should focus on power quality analysis, addressing critical factors like harmonic distortion, and frequency regulation to ensure that renewable energy integration does not compromise the grid's stability. Given Lesotho's projected power surplus in the development case and as more generators come online, for future studies, monitoring key reliability indices such as EDNS and LOLP will be critical for determining the quantity of electricity that may be sold. These indices will evaluate system performance and reliability, guaranteeing that extra power can be exported while maintaining stability and maximizing the benefits and revenue generated by exporting the power.

However, the current GEP and TEP models assumptions do not account for the need for energy storage, which could cause issues with balancing supply and demand, especially with more renewable energy sources coming online. Outdated equipment in substations further highlights the need for network upgrades to meet future energy demands. To ensure long-term energy security and system resilience, a thorough risk evaluation must be conducted, taking into account the impact of climate change, operational flexibility, and prospective energy market changes.

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